**DG 08-009**
**Attestation**

I affirm, based on my personal knowledge, information and belief that: (1) the cost and revenue statements and the supporting data submitted, which purport to reflect the books and records of EnergyNorth Natural Gas, Inc. d/b/a National Grid NH (the "Company"), do in fact set forth the results shown by such books and records and that all differences between the books and the test year data and any changes in the manner of recording an item on the utility's books during the test year have been expressly noted, and; (2) the proper amounts have been allocated to the Company from affiliates and that those amounts have been included in the Company's cost of service.

February 21, 2008

Kenneth Daly
Kenneth Daly, Senior Vice President and
Chief Financial Officer EnergyNorth
Natural Gas, Inc. d/b/a National Grid NH

I, Kenneth Daly, Senior Vice President and Chief Financial Officer EnergyNorth Natural Gas, Inc. d/b/a National Grid NH being first duly sworn, hereby depose and say that I have read the foregoing Attestation and the facts alleged therein are true to the best of my knowledge and belief.

Dated: February 21, 2008

Kenneth Daly

STATE OF NEW YORK
COUNTY OF KINGS

Sworn to and subscribed before me this 21st day of February, 2008.

Justice of the Peace/Notary Public
My Commission Expires: 3/13/2011

JOHN ALLOCCA
NOTARY PUBLIC, State of New York
No. 02AL4948263
Qualified in Kings County
Commission Expires March 13, 2011

## ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
### Schedule 1A - Summary of Operations & Maintenance Expense

| Operation & Maintenance Expenses | Reference | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|---|
| Gas Cost | Page 1 | 135,339,224 | (2,224,993) | 133,114,231 | 121,116,831 | 122,350,498 |
| Labor | Page 2 | 8,482,884 | (24,279) | 8,458,605 | 7,945,604 | 7,045,970 |
| Contract Labor | Page 3 | 816,846 | 19,894 | 836,740 | 840,921 | 756,280 |
| Health & Hospitalization | Page 4 | 1,254,037 | 206,116 | 1,460,153 | 1,125,114 | 1,121,656 |
| Other Employee Related Expenses & Benefits | Page 5 | 351,854 | - | 351,854 | 417,535 | 351,533 |
| Pensions | Page 6 | 1,782,213 | - | 1,782,213 | 2,162,486 | 1,970,971 |
| OPEB's | Page 7 | 1,111,404 | - | 1,111,404 | 1,266,675 | 1,262,469 |
| Payroll Taxes | Page 8 | 415,929 | (4,871) | 411,057 | 364,448 | 302,346 |
| Purchased Services | Page 9 | 2,672,261 | (4,227) | 2,668,034 | 2,658,705 | 2,576,920 |
| Postage | Page 10 | 334,254 | 25,069 | 359,324 | 350,829 | 306,830 |
| Contributions, Tickets & Sponsorships | Page 11 | 37,995 | (37,995) | - | 35,022 | 58,865 |
| Dues & Memberships | Page 12 | 46,464 | - | 46,464 | 39,000 | 47,769 |
| Other | Page 13 | 3,477,516 | - | 3,477,516 | 3,411,276 | 2,879,784 |
| Uncollectibles | Page 14 | 3,693,923 | 899,903 | 4,593,826 | 3,598,635 | 6,507,349 |
| GAC Offset | Page 15 | (3,474,004) | 3,474,004 | (0) | (3,924,004) | (4,894,870) |
| Program Changes | Page 16 | - | 1,597,365 | 1,597,365 | - | - |
| Synergy Savings | | - | (619,000) | (619,000) | - | - |
| | | 156,342,800 | 3,306,985 | 159,649,786 | 141,409,077 | 142,644,370 |
| Operation | | | | | | |
| Other Gas Supply | | 133,337,809 | (2,192,045) | 131,145,764 | 120,116,044 | 121,753,922 |
| Natural Gas Storage | | (2,291,901) | 2,306,380 | 14,479 | (2,820,253) | (4,599,734) |
| Transmission & Distribution | | 155,590 | 272 | 155,862 | 154,241 | 168,682 |
| Distribution | | 2,400,750 | 1,165,193 | 3,565,943 | 2,270,850 | 2,102,451 |
| Customer Accounts | | 5,067,693 | 2,545,918 | 7,613,611 | 4,965,836 | 7,329,620 |
| Customer Service | | 38,120 | 1,865 | 39,985 | 16,186 | 36,578 |
| Sales Expense | | 1,572,511 | 5,701 | 1,578,212 | 1,573,901 | 991,797 |
| Sales Promotion | | 108,080 | (72) | 108,008 | 84,292 | 73,078 |
| Admin and General | | 8,568,729 | 89,454 | 8,658,183 | 8,753,007 | 9,382,878 |
| Allocated Service Company | | 4,855 | (0) | 4,855 | 6,930 | 6,557 |
| Natural Gas Production and Gathering | | 2,583,367 | (33,403) | 2,549,964 | 1,568,942 | 1,116,410 |
| Total Operation | | 151,545,603 | 3,889,262 | 155,434,865 | 136,689,975 | 138,362,239 |
| Maintenance | | | | | | |
| Distribution | | 4,511,324 | 36,835 | 4,548,159 | 4,418,061 | 4,026,151 |
| Admin and General | | 13,097 | (7) | 13,090 | 25,657 | - |
| Natural Gas Production and Gathering | | 272,776 | (104) | 272,672 | 275,384 | 255,981 |
| Total Maintenance | | 4,797,197 | 36,724 | 4,833,921 | 4,719,102 | 4,282,132 |
| Total Synergy Savings | | - | (619,000) | (619,000) | - | - |
| Total Operation & Maintenance | | 156,342,800 | 3,306,985 | 159,649,786 | 141,409,077 | 142,644,371 |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Gas Cost**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | 135,339,224 | (2,224,993) | 133,114,231 | 121,116,831 | 122,350,498 |
| Corporate Services | - | - | - | - | - |
| Utility Services | - | - | - | - | - |
| Total | 135,339,224 | (2,224,993) | 133,114,231 | 121,116,831 | 122,350,498 |
| | | | | | |
| Operation | | | | | |
| Other Gas Supply | 133,335,057 | (2,192,045) | 131,143,013 | 120,112,526 | 121,631,400 |
| Natural Gas Production and Gathering | 2,004,167 | (32,949) | 1,971,218 | 1,004,305 | 719,098 |
| Total Operation | 135,339,224 | (2,224,993) | 133,114,231 | 121,116,831 | 122,350,498 |
| | | | | | |
| Maintenance | - | - | - | - | - |
| Total Maintenance | - | - | - | - | - |
| | | | | | |
| Total Operation & Maintenance | 135,339,224 | (2,224,993) | 133,114,231 | 121,116,831 | 122,350,498 |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Gas Cost**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year |
|---|---|---|---|
| Firm COG Rev- Sales | (126,751,237) | - | (126,751,237) |
| Firm COG Rev- Transportation | (14,553) | - | - |
| Firm LDAF Rev- Sales | (4,024,761) | - | (4,024,761) |
| Firm LDAF Rev- Sales | (1,079,295) | - | - |
| Interruptible Gas Cost | (368,844) | 368,844 | - |
| Interruptible Transportation | - | - | - |
| Non Core Gas Costs | (12,147) | - | (12,147) |
| Sub-total | (132,250,836) | 368,844 | (131,881,992) |
| | | | |
| Other Gas Costs | | | |
| Unbilled Revenue | (267,966) | - | (267,966) |
| Broker Balancing | (645,686) | 645,686 | - |
| Off System Sales | (3,101,836) | 3,101,836 | - |
| Normalized Weather adjustment | - | (5,323,516) | (5,323,516) |
| Low Income Assistance Program | 885,330 | - | 885,330 |
| Other- Residual | 41,761 | (41,761) | - |
| Reallocate gas cost related bad debt from Acct. 90400 to Gas cost | - | 1,167,508 | 1,167,508 |
| Reallocate Production & Storage from Acct 8/492k to Gas Costs | - | 2,306,405 | 2,306,405 |
| Sub-total | (3,088,397) | 1,856,158 | (1,232,239) |
| | | | |
| Total | (135,339,233) | 2,225,002 | (133,114,231) |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Labor**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | 4,223,449 | 66,191 | 4,289,640 | 4,020,938 | 3,766,528 |
| Corporate Services | 4,204,005 | (93,002) | 4,111,003 | 3,883,760 | 3,238,481 |
| Utility Services | 55,430 | 2,532 | 57,962 | 40,906 | 40,962 |
| Total | 8,482,884 | (24,279) | 8,458,605 | 7,945,604 | 7,045,970 |
| | | | | | |
| Operation | | | | | |
| Other Gas Supply | 47 | (0) | 46 | 47 | 65,963 |
| Natural Gas Storage | 1,800 | (5) | 1,795 | 1,800 | - |
| Transmission & Distribution | 110,985 | (318) | 110,667 | 108,590 | 117,193 |
| Distribution | 1,491,750 | (4,270) | 1,487,481 | 1,402,091 | 1,228,213 |
| Customer Accounts | 1,235,980 | (3,538) | 1,232,442 | 1,122,817 | 947,531 |
| Sales Expense | 557,906 | (1,597) | 556,309 | 537,828 | 525,571 |
| Sales Promotion | - | - | - | - | - |
| Admin and General | 2,510,658 | (7,186) | 2,503,472 | 2,347,091 | 1,933,570 |
| Allocated Service Company | - | - | - | - | (515) |
| Natural Gas Production and Gathering | 354,270 | (1,014) | 353,256 | 322,633 | 294,420 |
| | 6,263,395 | (17,927) | 6,245,468 | 5,842,896 | 5,111,946 |
| | | | | | |
| Maintenance | | | | | |
| Distribution | 2,065,937 | (5,913) | 2,060,024 | 1,958,165 | 1,800,511 |
| Natural Gas Production and Gathering | 153,552 | (439) | 153,113 | 144,543 | 133,513 |
| Total Maintenance | 2,219,489 | (6,352) | 2,213,137 | 2,102,708 | 1,934,025 |
| | | | | | |
| Total Operation & Maintenance | 8,482,884 | (24,279) | 8,458,605 | 7,945,604 | 7,045,970 |

Notes:
*Allocation based on actual year ended June 30, 2007

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Operating Expenses by Component
## Labor - Adjustments

| Company Affiliation Wage Increase | *Union* | *Management* | *Adjustment* |
|---|---|---|---|
| *ENERGYNORTH (06)* | 108,125 | 70,136 | 178,261 |
| *Corporate Services (31)* | 50,291 | 263,293 | 313,584 |
| *Utility Services (32)* | 1,312 | 2,186 | 3,498 |
| ***Sub Total*** | 159,729 | 335,615 | 495,343 |

| Company Affiliation | *Union Gainsharing* | *Management Incentive Compensation* | *Adjustment* |
|---|---|---|---|
| *ENERGYNORTH (06)* | (12,890) | (99,180) | (112,071) |
| *Corporate Services (31)* | (7,138) | (399,448) | (406,586) |
| *Utility Services (32)* | (269) | (697) | (966) |
| ***Sub Total*** | (20,297) | (499,325) | (519,622) |

| | Wage Increase | Gainsharing & Incentive Compensation | Total Adjustment |
|---|---|---|---|
| *ENERGYNORTH (06)* | 178,261 | (112,071) | **66,191** |
| *Corporate Services (31)* | 313,584 | (406,586) | **(93,002)** |
| *Utility Services (32)* | 3,498 | (966) | **2,532** |
| ***Grand Total*** | 495,343 | (519,622) | **(24,279)** |

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Operating Expenses by Component
## Labor - Summary of Union Employees

| **Employee Affiliation** | *O&M* | *Union Wage* | *Adjustment* |
|---|---|---|---|
| **Unions** | *Labor Cost* | *Increase* | |
| ENERGYNORTH (06) | 3,364,204 | 3.21% | 108,125 |
| *Corporate Services (31)* | 978,367 | 5.14% | 50,291 |
| *Utility Services (32)* | 28,648 | 4.58% | 1,312 |
| ***Total Union*** | 4,371,218 | | 159,729 |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Labor - Summary of Management Employees**

| **Employee Affiliation** | *O&M* | *Management* | *Adjustment* |
|---|---|---|---|
| **Management** | *Labor Cost* | *Wage Increase* | |
| ENERGYNORTH (06) | 859,245 | 8.16% | 70,136 |
| *Corporate Services (31)* | 3,225,638 | 8.16% | 263,293 |
| *Utility Services (32)* | 26,782 | 8.16% | 2,186 |
| ***Total Management*** | 4,111,665 | | 335,615 |

## ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
### Operating Expenses by Component
### Labor - Summary of Employees in Corporate Services (31) (CSV)

| Employee Affiliation | *Headcount* | *Total Salaries (Current)* | *Average Salary* | Overall Increases Historical Yr to Rate Yr | *Effective Co %* | *Union Wage Increase* |
|---|---|---|---|---|---|---|
| **Management** | 1,427 | 130,245,938 | 91,273 | 8.16% | | |
| **Bargaining** | | | | | | |
| *Local 101* | 419 | 19,337,536 | 46,152 | 4.23% | 23.42% | 0.99% |
| *Local 3* | 5 | 343,215 | 68,643 | 4.23% | 0.42% | 0.02% |
| *Local 1049* | 165 | 11,330,509 | 68,670 | 5.51% | 13.73% | 0.76% |
| *Local 1381* | 683 | 35,450,474 | 51,904 | 5.51% | 42.94% | 2.37% |
| *Local 012* | 10 | 675,610 | 67,561 | 5.19% | 0.82% | 0.04% |
| *Local 120* | 1 | 51,716 | 51,716 | 3.21% | 0.06% | 0.00% |
| *Local 318* | 2 | 133,096 | 66,548 | 5.70% | 0.16% | 0.01% |
| *Local CAP* | 2 | 121,674 | 60,837 | 4.93% | 0.15% | 0.01% |
| *Local 12003* | 247 | 15,108,529 | 61,168 | 5.19% | 18.30% | 0.95% |
| ***Total Unions*** | **1,534** | **82,552,357** | **53,815** | | **100.00%** | **5.14%** |
| ***Grand Total*** | **2,961** | **212,798,295** | **71,867** | | | |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Labor - Summary of Employees**

| Employee Affiliation | Headcount | Total Salaries (Current) | Average Salary | Overall Increases Historical Yr to Rate Yr | Effective Co % | Union Wage Increase |
|---|---|---|---|---|---|---|
| Management | 15 | 1,067,050 | 71,137 | 8.16% | | |
| Bargaining | | | | | | |
| *Local 120* | 69 | 3,873,759 | 56,141 | 3.21% | 100.00% | 3.21% |
| *Total Unions* | 69 | 3,873,759 | 56,141 | | 100.00% | 3.21% |
| *Grand Total* | 84 | 4,940,809 | 58,819 | | | |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Labor - Summary of Employees in Utility Services (32) (USV)**

| Employee Affiliation | Headcount | Total Salaries (Current) | Average Salary | Overall Increases Historical Yr to Rate Yr | Effective Co % | Union Wage Increase |
|---|---|---|---|---|---|---|
| **Management** | 147 | 13,623,325.00 | 92,675.68 | 8.16% | | |
| **Bargaining** | | | | | | |
| *Local 101* | 65 | 4,257,463.01 | 65,499.43 | 4.23% | 69.36% | 2.93% |
| *Local 3* | 3 | 202,070.28 | 67,356.76 | 4.23% | 3.29% | 0.14% |
| *Local 1049* | 13 | 939,161.60 | 72,243.20 | 5.51% | 15.30% | 0.84% |
| *Local 1381* | 13 | 739,277.76 | 56,867.52 | 5.51% | 12.04% | 0.66% |
| ***Total Unions*** | **94** | **6,137,972.65** | **65,297.58** | | **100.00%** | **4.58%** |
| *Grand Total* | **241** | **19,761,297.65** | **81,997.09** | | | |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Incentive Compensation**

| | *ENERGYNORTH (06) Direct* | *Corporate Services (31)* | *Utility Services (32)* |
|---|---|---|---|
| *Actual Incentive Compensation* | 303,744 | 42,321,639 | 2,476,435 |
| *Incentive Compensation charged to O&M* | 146,969 | 736,361 | 2,150 |
| *Percentage* | 48.39% | 1.74% | 0.09% |
| Target Incentive Compensation | 98,766 | 19,363,745 | 1,673,667 |
| (over) or Under Accrual | (204,978) | (22,957,894) | (802,768) |
| Adjustments | (99,180) | (399,448) | (697) |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Gainsharing**

| | *ENERGYNORTH (06) Direct* | *Corporate Services (31)* | *Utility Services (32)* |
|---|---|---|---|
| *Actual Gainsharing* | ***75,592*** | ***1,363,793*** | ***178,135*** |
| *Gainsharing charged to O&M* | 55,726 | 15,472 | 719 |
| *Percentage* | 73.72% | 1.13% | 0.40% |
| | | | |
| Target Gainsharing | 58,106 | 734,595 | 111,488 |
| (over) or Under Accrual | (17,486) | (629,198) | (66,647) |
| | | | |
| Adjustments | (12,890) | (7,138) | (269) |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Contract Labor**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | 654,442 | 19,894 | 674,336 | 676,908 | 624,952 |
| Corporate Services | 162,404 | - | 162,404 | 164,013 | 131,328 |
| Utility Services | - | - | - | - | - |
| Total | 816,846 | 19,894 | 836,740 | 840,921 | 756,280 |
| | | | | | |
| Operation | | | | | |
| Transmission & Distribution | - | | - | - | 9,798 |
| Distribution | 174,701 | 4,231 | 178,931 | 170,516 | 134,014 |
| Admin and General | (4,962) | - | (4,962) | (5,072) | 15 |
| Natural Gas Production and Gathering | - | - | - | 6,030 | 13,560 |
| Total Operation | 169,739 | 4,231 | 173,969 | 171,474 | 157,387 |
| | | | | | |
| Maintenance | | | | | |
| Distribution | 646,848 | 15,664 | 662,512 | 665,199 | 593,919 |
| Natural Gas Production and Gathering | 259 | - | 259 | 4,248 | 4,974 |
| Total Maintenance | 647,107 | 15,664 | 662,771 | 669,447 | 598,893 |
| | | | | | |
| Total Operation & Maintenance | 816,846 | 19,894 | 836,740 | 840,921 | 756,280 |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Contract Labor**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | | Pro Forma Test Year |
|---|---|---|---|---|
| EnergyNorth Contract Labor | 654,442 | 19,894 | | 674,336 |
| Total | 654,442 | 19,894 | | 674,336 |
| | | | | |
| Breakout of EnergyNorth Contract Labor | | | | |
| Paving | 574,986 | 19,894 | * | 594,880 |
| All Other Contract Labor | 79,456 | - | | 79,456 |
| Total Operation | 654,442 | 19,894 | | 674,336 |

* Paving Contracts for EnergyNorth were escalated 3.46%. EnergyNorth uses Brenton Contracting (which comprise 8% of total Contact Labor) and R.H. White (which comprise 92% of total Contract Labor) for paving. Effective 1/1/2008, the paving costs per contractual agreements increased 3% for Benton Contracting and 3.5% for R.H. White. The weighted average increase is 3.46%.

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Health & Hospitalization**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| EnergyNorth | 778,055 | 143,052 | 921,106 | 700,912 | 769,806 |
| Corporate Services | 469,340 | 62,030 | 531,370 | 419,267 | 347,496 |
| Utility Services | 6,642 | 1,035 | 7,677 | 4,935 | 4,354 |
| Total | 1,254,037 | 206,116 | 1,460,153 | 1,125,114 | 1,121,656 |
| | | | | | |
| Operation | | | | | |
| Other Gas Supply | - | - | - | - | 7,242 |
| Transmission & Distribution | 3,913 | 643 | 4,556 | 3,317 | 3,506 |
| Distribution | 67,697 | 11,127 | 78,823 | 64,380 | 60,299 |
| Customer Accounts | 114,110 | 18,755 | 132,865 | 98,748 | 76,016 |
| Sales Expense | 47,222 | 7,762 | 54,984 | 44,138 | 44,110 |
| Sales Promotion | - | - | - | - | - |
| Admin and General | 831,517 | 136,670 | 968,187 | 722,306 | 723,401 |
| Natural Gas Production and Gathering | 4,996 | 821 | 5,818 | 5,733 | 4,484 |
| Total Operation | 1,069,455 | 175,778 | 1,245,233 | 938,621 | 919,059 |
| | | | | | |
| Maintenance | | | | | |
| Distribution | 181,660 | 29,858 | 211,517 | 183,421 | 200,013 |
| Natural Gas Production and Gathering | 2,922 | 480 | 3,402 | 3,071 | 2,583 |
| Total Maintenance | 184,582 | 30,338 | 214,920 | 186,493 | 202,597 |
| | | | | | |
| Total Operation & Maintenance | 1,254,037 | 206,116 | 1,460,153 | 1,125,114 | 1,121,656 |

Notes:
*Allocation based on actual year ended June 30, 2007

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Operating Expenses by Component
## Health & Hospitalization
## Adjustments

| Health Care Increases | | | |
|---|---|---|---|
| | *Amount* | *Percentage* | *Adjustment* |
| *ENERGYNORTH (06) Direct* | 778,055 | 18.39% | 143,052 |
| *Corporate Services (31)* | 469,340 | 13.22% | 62,030 |
| *Utility Services (32)* | 6,642 | 15.58% | 1,035 |
| ***Total*** | **1,254,037** | | **206,116** |
| | | | 16.44% |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Other Employee Related Expenses & Benefits**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | 129,345 | | 129,345 | 182,185 | 189,258 |
| Corporate Services | 221,000 | | 221,000 | 233,940 | 160,355 |
| Utility Services | 1,509 | | 1,509 | 1,410 | 1,921 |
| Total | 351,854 | - | 351,854 | 417,535 | 351,533 |
| | | | | | |
| Operation | | | | | |
| Other Gas Supply | 1,504 | | 1,504 | 1,476 | 2,108 |
| Transmission & Distribution | 904 | | 904 | 854 | 1,034 |
| Distribution | 10,914 | | 10,914 | 10,006 | 8,904 |
| Customer Accounts | 27,657 | | 27,657 | 23,538 | 15,746 |
| Sales Expense | 39,369 | | 39,369 | 32,466 | 42,066 |
| Sales Promotion | - | | - | - | - |
| Admin and General | 233,211 | | 233,211 | 310,049 | 248,744 |
| Natural Gas Production and Gathering | 2,844 | | 2,844 | 3,724 | 2,980 |
| Total Operation | 316,403 | - | 316,403 | 382,114 | 321,582 |
| | | | | | |
| Maintenance | | | | | |
| Distribution | 34,162 | | 34,162 | 33,939 | 28,546 |
| Natural Gas Production and Gathering | 1,289 | | 1,289 | 1,482 | 1,405 |
| Total Maintenance | 35,451 | - | 35,451 | 35,421 | 29,951 |
| | | | | | |
| Total Operation & Maintenance | 351,854 | - | 351,854 | 417,535 | 351,533 |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Pensions**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | 1,296,585 | | 1,296,585 | 1,552,916 | 1,482,861 |
| Corporate Services | 482,102 | | 482,102 | 602,625 | 482,745 |
| Utility Services | 3,526 | | 3,526 | 6,946 | 5,365 |
| Total | 1,782,213 | - | 1,782,213 | 2,162,486 | 1,970,971 |
| | | | | | |
| Operation | | | | | |
| Other Gas Supply | - | | - | - | 10,159 |
| Transmission & Distribution | 4,167 | | 4,167 | 4,962 | 4,522 |
| Distribution | 83,357 | | 83,357 | 91,916 | 73,212 |
| Customer Accounts | 123,830 | | 123,830 | 145,824 | 107,116 |
| Sales Expense | 51,119 | | 51,119 | 67,323 | 61,910 |
| Sales Promotion | - | | - | - | - |
| Admin and General | 1,284,388 | | 1,284,388 | 1,561,481 | 1,440,428 |
| Natural Gas Production and Gathering | 5,447 | | 5,447 | 8,120 | 6,273 |
| Total Operation | 1,552,308 | - | 1,552,308 | 1,879,626 | 1,703,618 |
| | | | | | |
| Maintenance | | | | | |
| Distribution | 226,704 | | 226,704 | 278,437 | 263,744 |
| Natural Gas Production and Gathering | 3,200 | | 3,200 | 4,423 | 3,608 |
| Total Maintenance | 229,905 | - | 229,905 | 282,860 | 267,352 |
| | | | | | |
| Total Operation & Maintenance | 1,782,213 | - | 1,782,213 | 2,162,486 | 1,970,971 |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**OPEBs**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | 573,490 | | 573,490 | 704,810 | 748,318 |
| Corporate Services | 526,722 | | 526,722 | 551,838 | 504,885 |
| Utility Services | 11,193 | | 11,193 | 10,027 | 9,266 |
| Total | 1,111,404 | - | 1,111,404 | 1,266,675 | 1,262,469 |
| | | | | | |
| Operation | | | | | |
| Other Gas Supply | - | | - | - | 10,684 |
| Transmission & Distribution | 4,110 | | 4,110 | 4,258 | 4,247 |
| Distribution | 54,456 | | 54,456 | 55,730 | 50,333 |
| Customer Accounts | 135,581 | | 135,581 | 133,425 | 112,480 |
| Sales Expense | 56,050 | | 56,050 | 61,588 | 64,027 |
| Sales Promotion | - | | - | - | - |
| Admin and General | 700,985 | | 700,985 | 834,069 | 845,865 |
| Natural Gas Production and Gathering | 5,494 | | 5,494 | 7,347 | 6,531 |
| Total Operation | 956,676 | - | 956,676 | 1,096,418 | 1,094,168 |
| | | | | | |
| Maintenance | | | | | |
| Distribution | 151,526 | | 151,526 | 166,320 | 164,672 |
| Natural Gas Production and Gathering | 3,202 | | 3,202 | 3,938 | 3,629 |
| Total Maintenance | 154,728 | - | 154,728 | 170,258 | 168,301 |
| | | | | | |
| Total Operation & Maintenance | 1,111,404 | - | 1,111,404 | 1,266,675 | 1,262,469 |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Payroll Taxes**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| EnergyNorth | 106,940 | 1,676 | 108,616 | 101,024 | 88,696 |
| Corporate Services | 304,738 | (6,741) | 297,996 | 260,176 | 210,521 |
| Utility Services | 4,251 | 194 | 4,445 | 3,248 | 3,128 |
| Total | 415,929 | (4,871) | 411,057 | 364,448 | 302,346 |
| | | | | | |
| Operation | | | | | |
| Other Gas Supply | - | - | - | - | 4,296 |
| Transmission & Distribution | 2,424 | (28) | 2,396 | 2,066 | 1,825 |
| Distribution | 31,913 | (374) | 31,539 | 28,406 | 22,241 |
| Customer Accounts | 78,284 | (917) | 77,367 | 64,165 | 46,618 |
| Sales Expense | 32,285 | (378) | 31,907 | 28,633 | 27,397 |
| Sales Promotion | - | - | - | - | - |
| Admin and General | 179,249 | (2,099) | 177,149 | 154,315 | 121,381 |
| Natural Gas Production and Gathering | 3,173 | (37) | 3,136 | 3,676 | 2,770 |
| Total Operation | 327,329 | (3,834) | 323,495 | 281,260 | 226,528 |
| | | | | | |
| Maintenance | | | | | |
| Distribution | 86,737 | (1,016) | 85,721 | 81,236 | 74,272 |
| Natural Gas Production and Gathering | 1,863 | (22) | 1,842 | 1,952 | 1,546 |
| Total Maintenance | 88,600 | (1,038) | 87,562 | 83,188 | 75,817 |
| | | | | | |
| Total Operation & Maintenance | 415,929 | (4,871) | 411,057 | 364,448 | 302,346 |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Payroll Taxes**

| | 12 Months Ending June 30, 2007 | Overall increase | Total |
|---|---|---|---|
| EnergyNorth (06) | 106,940 | 1.57% | 1,676 |
| Corporate Services (31) | 304,738 | -2.21% | (6,741) |
| Utility Services (32) | 4,251 | 4.57% | 194 |
| Total | 415,929 | | (4,871) |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Purchased Services**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | 1,047,208 | (4,227) | 1,042,981 | 896,776 | 727,183 |
| Corporate Services | 1,623,586 | - | 1,623,586 | 1,760,112 | 1,849,434 |
| Utility Services | 1,467 | - | 1,467 | 1,818 | 303 |
| Engineering Services | - | - | - | - | - |
| Total | 2,672,261 | (4,227) | 2,668,034 | 2,658,705 | 2,576,920 |
| | | | | | |
| Operation | 364 | (1) | 363 | | |
| Other Gas Supply | 12,693 | (20) | 12,673 | 565 | 2,459 |
| Natural Gas Storage | 16,041 | (25) | 16,015 | 12,693 | - |
| Transmission & Distribution | 208,738 | (330) | 208,408 | 15,224 | 14,452 |
| Distribution | 382,197 | (605) | 381,592 | 188,369 | 190,423 |
| Customer Accounts | (44,467) | 70 | (44,397) | 416,888 | 435,891 |
| Customer Service | 23,089 | (37) | 23,052 | 527 | 7,765 |
| Sales Expense | 45,795 | (72) | 45,723 | 24,983 | 23,310 |
| Sales Promotion | 1,288,817 | (2,039) | 1,286,778 | 39,124 | 32 |
| Admin and General | 4 | (0) | 4 | 1,331,688 | 1,458,195 |
| Allocated Service Company | 141,655 | (224) | 141,431 | 18 | 7 |
| Natural Gas Production and Gathering | - | - | - | 124,926 | 8,591 |
| Total Operations | 2,074,925 | (3,282) | 2,071,643 | 2,155,004 | 2,141,127 |
| | | | | | |
| Maintenance | | | - | | |
| Distribution | 514,886 | (814) | 514,072 | 424,361 | 387,420 |
| Admin and General | 4,451 | (7) | 4,443 | 5,581 | - |
| Natural Gas Production and Gathering | 77,999 | (123) | 77,876 | 73,760 | 48,374 |
| Total Maintenance | 597,336 | (945) | 596,391 | 503,702 | 435,794 |
| | | | | | |
| Total Operation & Maintenance | 2,672,261 | (4,227) | 2,668,034 | 2,658,705 | 2,576,920 |

Notes:
*Allocation based on actual year ended June 30, 2007

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Operating Expenses by Component
## Purchased Services

| Date | Vendor | Amount |
|---|---|---|
| 10/12/2006 | McLane, Graf, Raulerson & Middleton | 1,198.00 |
| 6/12/2007 | McLane, Graf, Raulerson & Middleton | 1,536.96 |
| 2/13/2007 | McLane, Graf, Raulerson & Middleton | 1,492.20 |
| | | **4,227.16** |

Fees incurred for services rendered in connection with the petition to increase the short term debt limit that are not chargeable to customers

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Postage**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | - | - | - | - | - |
| Corporate Services | 334,254 | 25,069 | 359,324 | 350,829 | 306,830 |
| Utility Services | - | - | - | - | - |
| Total | 334,254 | 25,069 | 359,324 | 350,829 | 306,830 |
| | | | | | |
| Operation | | | | | |
| Distribution | 1 | 0 | 1 | - | - |
| Customer Accounts | 296,826 | 22,262 | 319,088 | 310,732 | 299,522 |
| Customer Service | 23,927 | 1,795 | 25,722 | 23,927 | (360) |
| Sales Expense | - | - | - | - | 97 |
| Sales Promotion | - | - | - | - | 45 |
| Admin and General | 13,500 | 1,013 | 14,513 | 16,169 | 7,527 |
| Total Operation | 334,254 | 25,069 | 359,324 | 350,829 | 306,830 |
| | | | | | |
| Maintenance | | | | | |
| Total Maintenance | - | - | - | - | - |
| | | | | | |
| Total Operation & Maintenance | 334,254 | 25,069 | 359,324 | 350,829 | 306,830 |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Postage**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | | Pro Forma Test Year |
|---|---|---|---|---|
| Corporate Services | 334,254 | 25,069 | * | 359,324 |
| Total | 334,254 | 25,069 | | 359,324 |

* The United States Postal Service increased postage rates effective May 14, 2007. The weighted average increase of the postal rates based on KeySpan mail mix was 7.5%.

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Contributions, Tickets & Sponsorships**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | 944 | (944) | - | - | 149 |
| Corporate Services | 37,010 | (37,010) | - | 35,022 | 58,708 |
| Utility Services | 42 | (42) | - | - | 8 |
| Total | 37,995 | (37,995) | - | 35,022 | 58,865 |
| | | | | | |
| Operation | | | | | |
| Distribution | 98 | (98) | - | - | 70 |
| Sales Expense | 49 | (49) | - | - | 47 |
| Admin and General | 36,905 | (36,905) | - | 35,022 | 58,612 |
| Natural Gas Production and Gathering | - | - | - | - | 65 |
| Total Operation | 37,052 | (37,052) | - | 35,022 | 58,794 |
| | | | | | |
| Maintenance | | | | | |
| Distribution | 944 | (944) | - | - | 47 |
| Natural Gas Production and Gathering | - | - | - | - | 25 |
| Total Maintenance | 944 | (944) | - | - | 71 |
| | | | | | |
| Total Operation & Maintenance | 37,995 | (37,995) | - | 35,022 | 58,865 |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Dues & Memberships**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | 21,140 | | 21,140 | 20,536 | 19,202 |
| Corporate Services | 25,323 | | 25,323 | 18,464 | 28,567 |
| Utility Services | 1 | | 1 | - | - |
| Total | 46,464 | - | 46,464 | 39,000 | 47,769 |
| | | | | | |
| Operation | | | | | |
| Transmission & Distribution | 18 | | 18 | 11 | 12 |
| Distribution | 60 | | 60 | 131 | 111 |
| Customer Accounts | 5 | | 5 | - | - |
| Sales Expense | 942 | | 942 | 521 | 2,465 |
| Admin and General | 24,932 | | 24,932 | 18,430 | 26,180 |
| Total Operation | 25,957 | - | 25,957 | 19,093 | 28,767 |
| | | | | | |
| Maintenance | | | | | |
| Distribution | 20,491 | | 20,491 | 19,769 | 18,999 |
| Natural Gas Production and Gathering | 16 | | 16 | 138 | 3 |
| Total Maintenance | 20,507 | - | 20,507 | 19,907 | 19,002 |
| | | | | | |
| Total Operation & Maintenance | 46,464 | - | 46,464 | 39,000 | 47,769 |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Other**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | 1,528,574 | | 1,528,574 | 1,615,321 | 1,699,659 |
| Corporate Services | 1,947,152 | | 1,947,152 | 1,794,922 | 1,169,074 |
| Utility Services | 1,790 | | 1,790 | 1,032 | 11,051 |
| Total | 3,477,516 | - | 3,477,516 | 3,411,276 | 2,879,784 |
| Operation | | | | | |
| Other Gas Supply | 837 | | 837 | 1,431 | 19,612 |
| Natural Gas Storage | 11 | | 11 | 11 | - |
| Transmission & Distribution | 13,028 | | 13,028 | 14,959 | 12,092 |
| Distribution | 277,066 | | 277,066 | 259,306 | 334,632 |
| Customer Accounts | 146,900 | | 146,900 | 140,310 | 61,711 |
| Customer Service | 58,660 | | 58,660 | (8,268) | 29,172 |
| Sales Expense | 764,480 | | 764,480 | 776,421 | 200,796 |
| Sales Promotion | 62,285 | | 62,285 | 45,168 | 73,000 |
| Admin and General | 1,469,529 | | 1,469,529 | 1,427,460 | 1,533,736 |
| Allocated Service Company | 4,851 | | 4,851 | 6,912 | 7,065 |
| Natural Gas Production and Gathering | 61,320 | | 61,320 | 82,448 | 57,638 |
| Total Operation | 2,858,966 | - | 2,858,966 | 2,746,158 | 2,329,455 |
| Maintenance | | | | | |
| Distribution | 581,429 | | 581,429 | 607,214 | 494,008 |
| Admin and General | 8,647 | | 8,647 | 20,076 | - |
| Natural Gas Production and Gathering | 28,474 | | 28,474 | 37,828 | 56,321 |
| Total Maintenance | 618,550 | - | 618,550 | 665,118 | 550,329 |
| Total Operation & Maintenance | 3,477,516 | - | 3,477,516 | 3,411,276 | 2,879,784 |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Uncollectibles**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | 3,693,923 | 899,903 | 4,593,826 | 3,598,635 | 6,507,349 |
| Corporate Services | - | - | - | - | - |
| Utility Services | - | - | - | - | - |
| Total | 3,693,923 | 899,903 | 4,593,826 | 3,598,635 | 6,507,349 |
| Operation | | | | | |
| Customer Accounts | 3,693,923 | 899,903 | 4,593,826 | 3,598,635 | 6,507,349 |
| Total Operation | 3,693,923 | 899,903 | 4,593,826 | 3,598,635 | 6,507,349 |
| Maintenance | | | | | |
| Total Maintenance | - | - | - | - | - |
| Total Operation & Maintenance | 3,693,923 | 899,903 | 4,593,826 | 3,598,635 | 6,507,349 |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Uncollectibles**

| | | |
|---|---|---|
| Total Revenues | Summary Exhibit | 180,859,301 |
| Uncollectible Rate | 3 Year Average Net Write Offs | 2.54% |
| Pro Forma Uncollectibles | | 4,593,826 |
| Test Year Uncollectibles | | 3,693,923 |
| Pro Forma Adjustment | | 899,903 |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**GAC Offset**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | (3,474,004) | 3,474,004 | - | (3,924,004) | (4,894,870) |
| Corporate Services | - | - | - | - | - |
| Utility Services | - | - | - | - | - |
| Total | (3,474,004) | 3,474,004 | - | (3,924,004) | (4,894,870) |
| Operation | | | | | |
| Natural Gas Storage | (2,306,405) | 2,306,405 | - | (2,834,757) | (4,599,734) |
| Customer Accounts | (1,167,599) | 1,167,599 | - | (1,089,247) | (1,280,360) |
| Admin and General | - | - | - | - | 985,225 |
| Total Operation | (3,474,004) | 3,474,004 | - | (3,924,004) | (4,894,870) |
| Maintenance | | | | | |
| Total Maintenance | - | - | - | - | - |
| Total Operation & Maintenance | (3,474,004) | 3,474,004 | - | (3,924,004) | (4,894,870) |

Notes:
*Allocation based on actual year ended June 30, 2007

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Operating Expenses by Component
Summary of Emergency Response and Enhanced Collection Efforts Program Changes

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year* | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|
| Provider Company | | | | | |
| Energy North | | 1,258,650 | 1,258,650 | | |
| Corporate Services | - | 338,715 | 338,715 | | |
| Utility Services | | - | - | | |
| Total | - | 1,597,365 | 1,597,365 | - | - |
| Operation | | | | | |
| Distribution | - | 1,154,907 | 1,154,907 | | |
| Customer Accounts | - | 442,457 | 442,457 | | |
| Total Operation | - | 1,597,365 | 1,597,365 | - | - |
| Maintenance | | | | | |
| Total Maintenance | - | - | - | - | - |
| Total Operation & Maintenance | - | 1,597,365 | 1,597,365 | - | - |

Notes:
*Allocation based on actual year ended June 30, 2007

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Program Changes Associated with Emergency Response***

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year |
|---|---|---|---|
| Energy North | - | 965,907 | 965,907 |
| Corporate Services | - | 189,000 | 189,000 |
| Total | - | 1,154,907 | 1,154,907 |

* Per the Order approving the National Grid Merger, the Company was authorized to add 7 employees to facilitate improving its Emergency Response to leak calls. Shown below is the annualized costs of 1 supervisor and 6 technicians and their associated non-labor costs. These individuals were added in July 2007.

| | | Provider Company | |
|---|---|---|---|
| | Annualized Cost | EnergyNorth | Corporate Services |
| Supervisory Labor (1 FTE) | 84,663 | 84,663 | - |
| Labor Burdens | 92,942 | 92,942 | - |
| Supervisory Non-Labor Costs | 29,800 | 2,800 | 27,000 |
| Total Supervisory Costs | 207,405 | 180,405 | 27,000 |
| Technician Labor (6 FTEs) | 357,023 | 357,023 | - |
| Labor Burdens | 365,484 | 365,484 | - |
| Technician Non-Labor Costs | 224,995 | 62,995 | 162,000 |
| Total Technician Costs | 947,502 | 785,502 | 162,000 |
| Total Costs | 1,154,907 | 965,907 | 189,000 |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Operating Expenses by Component**
**Program Changes Associated with Enhanced Collection Efforts***

| | 12 Months Ending June 30. 2007 | Pro Forma Adjustments | Pro Forma Test Year |
|---|---|---|---|
| Energy North | - | 292,742 | 292,742 |
| Corporate Services | - | 149,715 | 149,715 |
| Total | - | 442,457 | 442,457 |

* On November 11, 2007, the Company, the PUC Staff and the Office of Consumer Advocated entered into a partial settlement, which included the following provision related to the Company's bad debt allowance: "The Company will file a written plan setting forth its proposed collections process on a going- forward basis for review by Staff. The plan will be filed no later than with the Company's upcoming base rate case filing. The prudently incurred costs of the collections process described in the plan (including, on an annualized basis, any costs that are incremental to those in the company's test year) shall be recoverable through rates set in the base rate case." The Company has reviewed its collection processes and determined that an increase in field collection activity would have a positive impact on the percentage of bad debt write offs incurred by the Company. The costs filed here are relative to that increase. * *

| | | Provider Company | |
|---|---|---|---|
| | Annualized Cost | EnergyNorth | Corporate Services |
| Incremental Field Collection Labor (2 FTEs) | 119,008 | 119,008 | - |
| Labor Burdens | 121,828 | 121,828 | - |
| Non-Labor Costs | 74,998 | 20,998 | 54,000 |
| Total Technician Costs | 315,834 | 261,834 | 54,000 |
| Incremental Field labor to Reconnect Accounts locked for non-payment | 30,909 | 30,909 | |
| Contact Center Costs for Increased Number of Calls | 91,656 | - | 91,656 |
| Postage associated with Incremental Notices | 4,059 | - | 4,059 |
| Total Costs | 442,458 | 292,742 | 149,715 |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**

**Cost of Service Exhibits**
**Rate Base**
**Table of Contents**

Case No. DG-08-009
Exhibit No. #16

## ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
### Schedule 3 - Average Rate Base

| | Total Gas Plant In Service | Noninterest Bearing CWIP | Reserve for Depreciation (1) | (Total) Net Utility Plant Service |
|---|---|---|---|---|
| June 2006 | 256,048,074 | 4,061,805 | (86,895,808) | 173,214,071 |
| July | 258,529,222 | 2,991,893 | (87,389,034) | 174,132,081 |
| August | 257,400,623 | 5,294,486 | (87,957,995) | 174,737,114 |
| September | 259,664,652 | 4,076,567 | (88,427,685) | 175,313,534 |
| October | 260,247,367 | 4,946,382 | (89,000,314) | 176,193,434 |
| November | 261,925,597 | 9,654,002 | (89,286,828) | 182,292,770 |
| December | 263,405,591 | 4,036,131 | (89,611,827) | 177,829,896 |
| January | 266,516,831 | 2,551,274 | (90,109,657) | 178,958,448 |
| February | 266,808,496 | 3,111,650 | (90,748,792) | 179,171,354 |
| March | 266,789,959 | 3,662,591 | (91,360,626) | 179,091,924 |
| April | 266,554,819 | 4,443,037 | (91,868,166) | 179,129,690 |
| May | 266,542,565 | 6,400,091 | (92,438,371) | 180,504,285 |
| June 2007 | 270,444,136 | 1,858,805 | (92,523,376) | 179,779,566 |
| Subtotal | 3,420,877,933 | 57,088,714 | (1,167,618,479) | 2,310,348,168 |
| Less: | | | | - |
| 1/2 June 06 | 128,024,037 | 2,030,903 | (43,447,904) | 86,607,036 |
| 1/2 June 07 | 135,222,068 | 929,403 | (46,261,688) | 89,889,783 |
| | 263,246,105 | 2,960,305 | (89,709,592) | 176,496,819 |
| Total | 3,157,631,827 | 54,128,409 | (1,077,908,887) | 2,133,851,349 |
| | | | | - |
| Average (Total ÷ 12) | 263,135,986 | 4,510,701 | (89,825,741) | 177,820,946 |

| | |
|---|---|
| **Property Base Adjustments (EN 2-4 p2 of 4)** | (36,876,360) |
| **Adjusted Property Base** | 140,944,586 |
| **Working Capital (EN 2-4-1 p1 of 3)** | 7,092,752 |
| **Average Rate Base** | 148,037,338 |

(1) Includes:
(a) Includes Asset Retirement Obligation in Account 254 - other deferred credits - averaging ($782) thousand.
(b) Includes Contributions in aid of construction - averaging ($387) thousand.

## ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
### Schedule 3 - Summary of Property Base Adjustments

| | Reference | Amount |
|---|---|---|
| **Average Balance of:** | | |
| Unamortized Deferred Assets - Other | EN 2-4 p3 | 4,170,788 |
| Deferred Income Taxes | EN 2-4 p4 | (41,047,147) |
| **Net Property Base Adjustment** | | (36,876,360) |

## ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
### Schedule 3 - Unamortized Deferred Assets - Other

| | FAS-109 | Gas jobs in Progress | Other | Total |
|---|---|---|---|---|
| June 2006 | 2,745,991 | 1,364,417 | 8,063 | 4,118,471 |
| July | 2,745,991 | 1,370,173 | 11,678 | 4,127,842 |
| August | 2,745,991 | 1,384,079 | 11,735 | 4,141,804 |
| September | 2,745,991 | 1,413,208 | 11,790 | 4,170,989 |
| October | 2,745,991 | 1,413,208 | 11,848 | 4,171,047 |
| November | 2,745,991 | 1,416,680 | 11,876 | 4,174,547 |
| December | 2,745,991 | 1,418,006 | 8,404 | 4,172,401 |
| January | 2,745,991 | 1,418,006 | 8,463 | 4,172,460 |
| February | 2,745,991 | 1,409,898 | 8,517 | 4,164,406 |
| March | 2,745,991 | 1,426,167 | 8,576 | 4,180,734 |
| April | 2,745,991 | 1,443,842 | 8,634 | 4,198,467 |
| May | 2,745,991 | 1,443,842 | 8,695 | 4,198,527 |
| June 2007 | 2,745,991 | 1,479,242 | 8,754 | 4,233,987 |
| Subtotal | 35,697,883 | 18,400,768 | 127,032 | 54,225,683 |
| Less: | | | | |
| 1/2 June 06 | 1,372,996 | 682,209 | 4,032 | 2,059,236 |
| 1/2 June 07 | 1,372,996 | 739,621 | 4,377 | 2,116,994 |
| | 2,745,991 | 1,421,830 | 8,409 | 4,176,229 |
| Total | 32,951,892 | 16,978,938 | 118,624 | 50,049,454 |
| Average (Total ÷ 12) | 2,745,991 | 1,414,912 | 9,885 | 4,170,788 |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Schedule 3 - Deferred Income Taxes**

| | | Federal (1) | New Hampshire State (2) | Total |
|---|---|---|---|---|
| June 2006 | | (33,054,827) | (7,716,648) | (40,771,474) |
| July | | (33,201,648) | (7,755,616) | (40,957,265) |
| August | | (33,102,172) | (7,729,214) | (40,831,386) |
| September | | (32,956,219) | (7,698,599) | (40,654,819) |
| October | | (32,526,622) | (7,584,577) | (40,111,199) |
| November | | (33,466,616) | (7,621,295) | (41,087,911) |
| December | | (34,396,302) | (7,055,822) | (41,452,124) |
| January | | (34,157,083) | (6,992,329) | (41,149,413) |
| February | | (34,925,357) | (7,196,242) | (42,121,599) |
| March | | (33,872,741) | (6,924,983) | (40,797,724) |
| April | | (34,484,713) | (7,087,412) | (41,572,125) |
| May | | (34,761,122) | (7,160,775) | (41,921,898) |
| June 2007 | | (32,494,176) | (6,550,964) | (39,045,141) |
| | Subtotal | (437,399,599) | (95,074,478) | (532,474,077) |
| Less: | | | | |
| 1/2 June 06 | | (16,527,413) | (3,858,324) | (20,385,737) |
| 1/2 June 07 | | (16,247,088) | (3,275,482) | (19,522,570) |
| | | (32,774,502) | (7,133,806) | |
| Total | | (404,625,097) | (87,940,672) | (492,565,769) |
| Average (Total ÷ 12) | | (33,718,758) | (7,328,389) | (41,047,147) |

(1) Includes deferred investment tax credit averaging ($612) thousand.
(2) Includes rate case deferred of ($2.789) million.

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Schedule 3A - Working Capital**

| | Reference | Amount |
|---|---|---|
| Prepayments | EN 2-4-1 p2 | 155,604 |
| Cash Working Capital Allowance | EN 2-4-1 p3 | 6,937,148 |
| Total Working Capital | | 7,092,752 |

## ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Schedule 3A - Prepayments

| | Total |
|---|---|
| June 2006 | 1,868 |
| July | 1,246 |
| August | 623 |
| September | 65,440 |
| October | (150,453) |
| November | 518,747 |
| December | 432,341 |
| January | 396,981 |
| February | 254,733 |
| March | 171,774 |
| April | 115,208 |
| May | 58,641 |
| June 2007 | 2,075 |
| Subtotal | 1,869,223 |
| Less: | |
| 1/2 June 06 | 934 |
| 1/2 June 07 | 1,037 |
| | 1,972 |
| Total | 1,867,252 |
| Average (Total ÷ 12) | 155,604 |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Schedule 3A - Cash Working Capital Allowance**

| | | | |
|---|---|---|---|
| Operations & Maintenance Expense | | 156,342,800 | |
| Less: | | | |
| Purchased Gas | | 135,339,224 | |
| Uncollectible Losses Allowance | | 3,693,923 | |
| | | 139,033,147 | |
| | Net | 17,309,653 | |
| Cash Allowance at 1/7th of Net Operations & Maintenance Expense | | | 2,472,808 |
| Plus: | | | |
| Purchased Gas | | 135,339,224 | |
| Cash Allowance at 12.04/365 | | | 4,464,340 |
| **Total Cash Working Capital Allowance** | | | 6,937,148 |

## ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH

**Cost of Service Exhibits**
**Rate of Return**
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**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Overall Rate of Return**
**For Ratemaking Purposes**

| Item | Component Ratio (%) | Component Cost Rate(%) | Weighted Average Cost Rate (%) |
|---|---|---|---|
| Common Stock [1] | 50.00 | 11.50 | 5.75 |
| Long Term Debt | 50.00 | 7.02 | 3.51 |
| Short Term Debt [2] | | | |
| Total | 100.00 | | 9.26 |

[1] The Merger Settlement Agreement approved in Docket No. DG 06-107 stipulates that in this rate filing EnergyNorth is to use an imputed common equity ratio of 50% for determining its overall rate of return for ratemaking purposes.

[2] As approved in Docket No. DG 06-122 all short-term debt outstanding as of June 30, 2007 is being refinanced with long-term debt issued by and pushed down from the parent company as shown on Exhibit EN 3-5.

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Capital Structure**
**At June 30, 2007**

| Item | Amount ($) | Component Ratio |
|---|---|---|
| Common Equity [1] | | |
| Stock | 223,653,012 | |
| Surplus | 11,355,804 | |
| Retained Earnings | (64,430,606) | |
| Total | 170,578,210 | 0.7044 |
| | | |
| Preferred Stock | | |
| Stock | 0 | |
| Total | 0 | 0.0000 |
| | | |
| Long Term Debt | | |
| Mortgage Debt | 0 | |
| L-T Notes | 40,000,000 | |
| PCRB Bonds | 0 | |
| Industrial Revenue Bonds | 0 | |
| Total | 40,000,000 | 0.1652 |
| | | |
| Short-Term Debt | 31,585,532 | 0.1304 |
| | | |
| Total Capital | 242,163,742 | 1.0000 |

[1] Includes goodwill of $92,065,000.

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Capital Structure Excluding Goodwill**
**At June 30, 2007**

| Item | Amount ($) | Component Ratio |
|---|---|---|
| Total Common Equity [1] | 78,513,470 | 0.5231 |
| Preferred Stock | | |
| Stock | 0 | |
| Total | 0 | 0.0000 |
| Long Term Debt | | |
| Mortgage Debt | 0 | |
| L-T Notes | 40,000,000 | |
| PCRB Bonds | 0 | |
| Industrial Revenue Bonds | 0 | |
| Total | 40,000,000 | 0.2665 |
| Short-Term Debt | 31,585,532 | 0.2104 |
| Total Capital | 150,099,002 | 1.0000 |

[1] Excludes goodwill of $92,065,000

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Historical Capital Structure ($)**
**At December 31 of Each Year**

| Item | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|
| Common Stock [1] | 166,084,732 | 167,280,328 | 161,500,256 | 155,939,949 | 150,537,553 |
| Preferred Stock | 0 | 0 | 0 | 0 | 0 |
| Long Term Debt | 40,000,000 | 40,000,000 | 40,000,000 | 80,186,533 | 80,625,333 |
| Short Term Debt | 40,153,808 | 53,739,311 | 64,376,873 | 22,741,100 | 3,594,296 |
| Total Capital | 246,238,540 | 261,019,639 | 265,877,129 | 258,867,582 | 234,757,182 |

[1] Includes goodwill of $92,065,000

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Capitalization Ratios**
**At December 31 of Each Year**

| Item | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|
| Common Stock [1] | 0.6745 | 0.6409 | 0.6074 | 0.6024 | 0.6412 |
| Preferred Stock | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Long Term Debt | 0.1624 | 0.1532 | 0.1504 | 0.3098 | 0.3434 |
| Short Term Debt | 0.1631 | 0.2059 | 0.2421 | 0.0878 | 0.0153 |
| Total Capital | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |

[1] Includes goodwill of $92,065,000

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Weighted Average Cost of Long-Term Debt**
**Pro Forma At June 30, 2008**
**($)**

| Long-Term Notes | Term (Yrs) | Issuance Date | Amount Issued @ Face Value | Amount Outstanding @ Face Value | Total Issuance Expense & Call Premium | Unamortized Issuance Exp & Call Premium | Net Proceeds Outstanding | Amortization of Issuance Exp & Call Premium | Annual Interest | Annual Cost | Weighted Average Cost Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Inter-Company Promissory Note to Parent @ 5.803% | 30 | 4/1/2005 | 80,000,000 | 80,000,000 | 0 | 0 | 80,000,000 | 0 | 4,642,400 | 4,642,400 | |
| First Mortgage Bonds | | | | | | | | | | | |
| 9.70% Series B Due 2019 | Called on 8/3/2004 | 9/1/1989 | 7,000,000 | 0 | 3,283,950 | 2,848,758 | (2,848,758) | 109,465 | 0 | 109,465 | |
| 9.75% Series C Due 2020 | Called on 8/3/2004 | 9/1/1990 | 10,000,000 | 0 | 4,805,610 | 4,190,543 | (4,190,543) | 160,187 | 0 | 160,187 | |
| 8.44% Series D Due 2009 | Called on 8/3/2004 | 1/10/1992 | 5,000,000 | 0 | 518,368 | 185,108 | (185,108) | 16,017 | 0 | 16,017 | |
| 7.40% Series E Due 2027 | Called on 8/3/2004 | 9/30/1997 | 21,285,000 | 0 | 2,183,644 | 1,722,136 | (1,722,136) | 57,781 | 0 | 57,781 | |
| **Total Long Term Debt** | | | 123,285,000 | 80,000,000 | 10,791,572 | 8,946,545 | 71,053,455 | 343,450 | 4,642,400 | 4,985,850 | 7.02% |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Cost of Short Term Debt**
**Pro Forma**
**At June 30, 2007**

| Item | Cost Rate | Outstanding Amount ($) | |
|---|---|---|---|
| Bank Loans | | | |
| Loans from Individuals | | | |
| Commercial Paper | | | |
| Money Pool [1] | | 0 | |
| Total | | 0 | |
| Weighted Average Cost | | | |

[1] As approved in Docket No. DG 06-122, all short-term debt outstanding as of June 30, 2007 is being refinanced with long-term debt issued by and pushed down from the parent company as shown on Exhibit EN 3-5.

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Cost of Common Equity Capital**

See the testimony and exhibits of Paul R. Moul.

Recommended cost of common equity used in this filing is 11.5%.

## ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH

**Cost of Service Exhibits**
**Summary**
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**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Computation of Revenue Deficiency**

| | Reference | Updated Pro Forma |
|---|---|---|
| Rate Base Proposed | EN 2-4 | 148,037,338 |
| Rate of Return | EN 3-1 | 9.26% |
| Income Required | | 13,708,258 |
| Adjusted Net Operating Income | EN 2-2-1A | 7,822,254 |
| Deficiency | | 5,886,003 |
| Tax Effect | | 1.6814 |
| **Revenue Deficiency** | | **9,896,601** |
| Revenue Increase | EN 2-2-1A | 9,896,601 |
| Income Tax Rate | | 41% |
| Income Tax | EN 2-2-1A | 4,010,597 |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Schedule 1 - Operating Revenues**

**Energy North Jul 06-Jun 07**
**Total Revenue**

| | Revenue | | | COG | | | Margin | | |
|---|---|---|---|---|---|---|---|---|---|
| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year |
| Firm Sales Rev | 167,881,675 | - | 167,881,675 | (130,775,997) | - | (130,775,997) | 37,105,678 | - | 37,105,678 |
| Firm Transportation Rev | 4,611,850 | - | 4,611,850 | (1,093,848) | - | (1,093,848) | 3,518,002 | - | 3,518,002 |
| Interruptible Sales | 368,657 | (368,657) | - | (368,844) | 368,844 | - | (187) | 187 | - |
| Interruptible Transportation | 21,579 | (21,579) | - | - | - | - | 21,579 | (21,579) | - |
| Non Core | 694,211 | - | 694,211 | (12,147) | - | (12,147) | 682,064 | - | 682,064 |
| Sub-total | 173,577,972 | (390,235) | 173,187,737 | (132,250,836) | 368,844 | (131,881,992) | 41,327,136 | (21,391) | 41,305,745 |
| | | | | | | | | | |
| Late Payment Charges | 1,044,760 | - | 1,044,760 | - | - | - | 1,044,760 | - | 1,044,760 |
| Unbilled Revenue | 310,864 | - | 310,864 | (267,966) | - | (267,966) | 42,898 | - | 42,898 |
| Reconnect Fees | 298,420 | - | 298,420 | - | - | - | 298,420 | - | 298,420 |
| NG Check Fees | 7,225 | 14,450 | 21,675 | - | - | - | 7,225 | 14,450 | 21,675 |
| Sales Allowance | (25,089) | - | (25,089) | - | - | - | (25,089) | - | (25,089) |
| Broker Balancing | 692,711 | (692,711) | - | (645,686) | 645,686 | - | 47,025 | (47,025) | - |
| Broker Late Payment | 7,029 | (7,029) | - | - | - | - | 7,029 | (7,029) | - |
| Off System Sales | 2,921,758 | (2,921,758) | - | (3,101,836) | 3,101,836 | - | (180,078) | 180,078 | - |
| DSM Incentive | 169,465 | (169,465) | - | - | - | - | 169,465 | (169,465) | - |
| Financial Hedge | (140,239) | 140,239 | - | - | - | - | (140,239) | 140,239 | - |
| Wet Gas Therm Adjustment 2001-2007 | (2,265,266) | 2,265,266 | - | - | - | - | (2,265,266) | 2,265,266 | - |
| Wet Gas Therm Adj Jul 06-Jan 07 | - | (178,379) | (178,379) | - | - | - | - | (178,379) | (178,379) |
| Normalized Weather adjustment | - | 6,199,313 | 6,199,313 | - | (5,323,516) | (5,323,516) | - | 875,798 | 875,798 |
| Low Income Assistance Program | - | - | - | 885,330 | - | 885,330 | 885,330 | - | 885,330 |
| Other | (79,420) | 79,420 | - | 41,761 | (41,761) | - | (37,659) | 37,659 | - |
| Reallocate gas cost related bad debt from Acct. 90400 to Gas Cost | - | - | - | - | 1,167,508 | 1,167,508 | - | 1,167,508 | 1,167,508 |
| Reallocate Production & Storage from Acct. 8492k to Gas Costs | - | - | - | - | 2,306,405 | 2,306,405 | - | 2,306,405 | 2,306,405 |
| Sub-total | 2,942,218 | 4,729,346 | 7,671,564 | (3,088,397) | 1,856,158 | (1,232,239) | (146,179) | 6,585,505 | 6,439,325 |
| | | | | | | | | | |
| Total | 176,520,190 | 4,339,111 | 180,859,301 | (135,339,233) | 2,225,002 | (133,114,231) | 41,180,957 | 6,564,113 | 47,745,070 |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Summary of Pro Forma Adjustment Income or Expense**

| | Reference | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 |
|---|---|---|---|---|---|---|
| Operating Revenues | EN 2-2 | 176,520,190 | 4,339,111 | 180,859,301 | 160,839,242 | 166,215,324 |
| Operation & Maintenance Expenses | EN 2-2-2 Sum | 156,342,800 | 3,306,985 | 159,649,786 | 141,409,077 | 142,644,370 |
| Depreciation | EN 2-2-4 | 8,824,109 | (1,053,408) | 7,770,701 | 8,684,205 | 7,929,666 |
| Amortization | | - | - | - | - | - |
| Loss from Disposition of Property | | 113,812 | (113,812) | - | - | - |
| Taxes Other Than Income Taxes | EN 2-2-3, p1 | 3,762,548 | 50,413 | 3,812,960 | 3,744,352 | 3,270,262 |
| Total Operating Revenue Deductions | | 169,043,269 | 2,190,178 | 171,233,447 | 153,837,633 | 153,844,298 |
| Operating Income Before Federal Income Taxes | | 7,476,921 | 2,148,933 | 9,625,854 | 7,001,609 | 12,371,027 |
| State Income Taxes | EN 2-2-5 p1 | 194,223 | 184,077 | 378,300 | 158,502 | 668,332 |
| Federal Income Taxes | EN 2-2-5 p2 | 1,449,455 | (24,155) | 1,425,300 | 1,314,870 | 3,031,353 |
| Total Income Taxes | | 1,643,678 | 159,922 | 1,803,600 | 1,473,372 | 3,699,685 |
| Operating Income After Federal & State Income Taxes | | 5,833,244 | 1,989,011 | 7,822,254 | 5,528,237 | 8,671,342 |
| Rate Base | EN 2-4 p1 | 148,037,338 | - | 148,037,338 | | |
| Rate of Return | EN 3-1 | 3.94% | | 5.28% | | |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Attachment - Summary of Pro Forma Adjustment Income or Expense**

| | Reference | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year | Proposed Rate Increase | Rate Year |
|---|---|---|---|---|---|---|
| Operating Revenues | EN 2-2 | 176,520,190 | 4,339,111 | 180,859,301 | 9,896,601 | 190,755,901 |
| Operation & Maintenance Expenses | EN 2-2-2 Sum | 156,342,800 | 3,306,985 | 159,649,786 | - | 159,649,786 |
| Depreciation | EN 2-2-4 | 8,824,109 | (1,053,408) | 7,770,701 | - | 7,770,701 |
| Amortization | | - | - | - | - | - |
| Loss from Disposition of Property | | 113,812 | (113,812) | - | - | - |
| Taxes Other Than Income Taxes | EN 2-2-3, p1 | 3,762,548 | 50,413 | 3,812,960 | - | 3,812,960 |
| Total Operating Revenue Deductions | | 169,043,269 | 2,190,178 | 171,233,447 | - | 171,233,447 |
| Operating Income Before Income Taxes | | 7,476,921 | 2,148,933 | 9,625,854 | 9,896,601 | 19,522,455 |
| State Income Taxes | EN 2-2-5 p1 | 194,223 | 184,077 | 378,300 | 841,211 | 1,219,511 |
| Federal Income Taxes | EN 2-2-5 p2 | 1,449,455 | (24,155) | 1,425,300 | 3,169,386 | 4,594,686 |
| Total Income Taxes | | 1,643,678 | 159,922 | 1,803,600 | 4,010,597 | 5,814,197 |
| Operating Income After Federal & State Income Taxes | | 5,833,244 | 1,989,011 | 7,822,254 | 5,886,003 | 13,708,258 |
| Rate Base | EN 2-4 p1 | 148,037,338 | - | 148,037,338 | | 148,037,338 |
| Rate of Return | EN 3-1 | 3.94% | | 5.28% | | 9.26% |

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Schedule 1B - Summary of Taxes Other Than Income Taxes

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year |
|---|---|---|---|
| Property Taxes | 3,533,834 | 43,922 | 3,577,756 |
| Total Property Taxes | 3,533,834 | 43,922 | 3,577,756 |
| State | | | |
| Unemployment Insurance | 482 | 8 | 490 |
| Other | (31) | - | (31) |
| Total State Taxes | 451 | 8 | 459 |
| Federal | | | |
| FICA Tax | 409,107 | 6,412 | 415,519 |
| Unemployment Tax | 4,551 | 71 | 4,622 |
| Total Federal Taxes | 413,658 | 6,483 | 420,141 |
| Payroll Taxes Capitalized | (185,395) | - | (185,395) |
| Total Taxes Other than Income Taxes | 3,762,548 | 50,413 | 3,812,961 |

Note: Payroll Taxes increased by overall EnergyNorth payroll

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Schedule 1B - Summary of Taxes Other Than Income Taxes**
**Property Taxes**
**January 1, 2008 Bill as Received December 1, 2007**

| Taxing Authority | | |
|---|---|---|
| State of New Hampshire | Utility property Tax | 784,449 |
| Boston and Maine Railroad | Right of way | 2,473 |
| Allenstown | | 30,122 |
| Amherst | | 42,279 |
| Auburn | | 669 |
| Bedford | | 27,601 |
| Belmont | | 5,281 |
| Berlin | | 4,065 |
| Boscawen | | 7,466 |
| Bow | | 97,258 |
| Canterbury | | 8,000 |
| Concord | | 366,713 |
| Derry | | 34,031 |
| Franklin | | 36,133 |
| Gilford | | 7,023 |
| Goffstown | | 12,725 |
| Hollis | | 2,158 |
| Hooksett | | 141,539 |
| Hudson | | 152,402 |
| Laconia | | 65,505 |
| Litchfield | | 5,291 |
| Londonderry | | 324,564 |
| Loudon | | 24,704 |
| Manchester | | 491,306 |
| Merrimack | | 109,470 |
| Milford | | 35,188 |
| Nashua | | 586,653 |
| Northfield | | 16,842 |
| Pembroke | | 46,608 |
| Sanbornton | | 146 |
| Tilton | | 109,093 |
| **TOTAL ACTUAL TAXES** | | **3,577,756** |
| **TOTAL TEST YEAR** | | **3,533,834** |
| **PRO FORMA ADJUSTMENT** | | **(43,922)** |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Schedule 1C - Depreciation Expense**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments (1) | Pro Forma Test Year |
|---|---|---|---|
| Total Depreciation Expense | 8,824,109 | (1,053,408) | 7,770,701 |
| | 8,824,109 | (1,053,408) | 7,770,701 |

Note:
(1) Pro Forma Depreciation Adjustment reflects proposed accounting changes resulting from the Depreciation Study prepared by Witness Normand

## ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
### Schedule 1D - State Income Tax Computation - Utility Operations

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year | Proposed Rate Increase | Pro Forma Test Year |
|---|---|---|---|---|---|
| OPERATING INCOME BEFORE INCOME TAXES& INTEREST CHARGES | 7,476,921 | 2,148,933 | 9,625,854 | 9,896,601 | 19,522,455 |
| INTEREST CHARGES and Other Charges | 3,000,384 | 2,195,727 | 5,196,111 | - | 5,196,111 |
| OPERATING INCOME BEFORE INCOME TAXES | 4,476,537 | (46,793) | 4,429,744 | 9,896,601 | 14,326,344 |
| **SECTION 1 - FLOW THROUGH ITEMS** | | | | | |
| **Permanent Differences** | | | | | |
| Lobbying Expenses | (6,812) | 6,812 | - | - | - |
| Meals & Entertainment | (96) | - | (96) | - | (96) |
| Penalties & Fines | 6,750 | (6,750) | - | - | - |
| Medicare Income | 20,938 | - | 20,938 | - | 20,938 |
| Total Perm M's | 20,780 | 62 | 20,842 | - | 20,842 |
| Income Subject To Tax | 4,497,317 | (46,731) | 4,450,586 | 9,896,601 | 14,347,186 |
| Income Tax @ 8.5% | 382,272 | (3,972) | 378,300 | 841,211 | 1,219,511 |
| Accrual To Return Adjustment | | | | | |
| Current | 764,445 | (764,445) | - | - | - |
| Deferred | (952,494) | 952,494 | - | - | - |
| Total | (188,049) | 188,049 | - | - | - |
| **State Income Tax Expense** | 194,223 | 184,077 | 378,300 | 841,211 | 1,219,511 |
| **Timing Differences** | | | | | |
| Deferred Gas Costs | 3,487,990 | (3,487,990) | - | - | - |
| Gain/<Loss> on Sale of Assets | 95,276 | (95,276) | - | - | - |
| AFUDC Debt | (127,738) | - | (127,738) | - | (127,738) |
| Pension Cost | 1,077,059 | - | 1,077,059 | - | 1,077,059 |
| Unbilled Revenue | 4,589,307 | - | 4,589,307 | - | 4,589,307 |
| Unamortized Debt Expense | 28,898 | - | 28,898 | - | 28,898 |
| Bad Debts | (4,066,237) | - | (4,066,237) | - | (4,066,237) |
| Gas Research Institute | (137,379) | - | (137,379) | - | (137,379) |
| Incentive Plan | (83,619) | - | (83,619) | - | (83,619) |
| OPEB/FASB 106 | 6,610 | - | 6,610 | - | 6,610 |
| Performance Shares | (24,996) | - | (24,996) | - | (24,996) |
| Vacation Accrual | 15,035 | - | 15,035 | - | 15,035 |
| Environmental Clean Up Costs | (2,355,301) | - | (2,355,301) | - | (2,355,301) |
| Cathodic Protection | (39,640) | - | (39,640) | - | (39,640) |
| CIAC -- Deferral | 660,376 | - | 660,376 | - | 660,376 |
| Depreciation Expense -- Tax | (5,494,690) | - | (5,494,690) | - | (5,494,690) |
| Depreciation Expense -- Books | 5,075,925 | - | 5,075,925 | - | 5,075,925 |
| Removal Cost -- Deferral | 230,495 | | 230,495 | | 230,495 |
| Property Tax Deferral | 2,100,000 | - | 2,100,000 | - | 2,100,000 |
| Uniform Capitalization -- Section 263 | (2,557,837) | | (2,557,837) | | (2,557,837) |
| UNICAP -- Self-Constructed Assets | (841,404) | 841,401 | (3) | - | (3) |
| Total Timing M's | 1,638,130 | (2,741,865) | (1,103,735) | - | (1,103,735) |
| **Taxable Income** | 2,859,187 | 2,695,134 | 5,554,321 | 9,896,601 | 15,450,921 |
| Current Income Tax @ 8.5% | 243,031 | 229,086 | 472,117 | 841,211 | 1,313,328 |
| Current Accrual To Return Adjustment | 764,445 | (764,445) | - | - | - |
| **Current Income Tax Expense** | 1,007,476 | (535,359) | 472,117 | 841,211 | 1,313,328 |
| Deferred Income Tax Expense | 139,241 | (233,059) | (93,817) | - | (93,817) |
| Deferred Accrual To Return Adjustment | (952,494) | 952,494 | - | - | - |
| Deferred Income Tax Expense | (813,253) | 719,435 | (93,817) | - | (93,817) |
| **Total Income Tax Expense Deferred & Current** | 194,223 | 184,077 | 378,300 | 841,211 | 1,219,511 |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Schedule 1D - Federal Income Tax Computation - Utility Operations**

| | 12 Months Ending June 30, 2007 | Pro Forma Adjustments | Pro Forma Test Year | Proposed Rate Increase | Pro Forma Test Year |
|---|---|---|---|---|---|
| OPERATING INCOME BEFORE INCOME TAXES& INTEREST CHARGES | 7,476,921 | 2,148,933 | 9,625,854 | 9,896,601 | 19,522,455 |
| INTEREST CHARGES and Other Charges | 3,000,384 | 2,195,727 | 5,196,111 | - | 5,196,111 |
| OPERATING INCOME BEFORE INCOME TAXES | 4,476,537 | (46,793) | 4,429,744 | 9,896,601 | 14,326,344 |
| State Income Taxes | 382,272 | (3,972) | 378,300 | 841,211 | 1,219,511 |
| **SECTION I - FLOW THROUGH ITEMS** | | | | | |
| **Permanent Differences** | | | | | |
| Lobbying Expenses | (6,812) | 6,812 | - | - | - |
| Meals & Entertainment | (96) | - | (96) | - | (96) |
| Penalties & Fines | 6,750 | (6,750) | - | - | - |
| Medicare Income | 20,938 | | 20,938 | - | 20,938 |
| Total Perm M's | 20,780 | 62 | 20,842 | - | 20,842 |
| Income Subject To Tax | 4,115,045 | (42,759) | 4,072,286 | 9,055,390 | 13,127,675 |
| Income Tax @ 35% | 1,440,266 | (14,966) | 1,425,300 | 3,169,386 | 4,594,686 |
| Accrual To Return Adjustment | | | | | |
| Current | (294,618) | 294,618 | - | - | - |
| Deferred | 303,807 | (303,807) | - | - | - |
| Total | 9,189 | (9,189) | - | - | - |
| **Federal Income Tax Expense** | 1,449,455 | (24,155) | 1,425,300 | 3,169,386 | 4,594,686 |
| **Timing Differences** | | | | | |
| Deferred Gas Costs | 3,487,990 | (3,487,990) | - | - | - |
| Gain/<Loss> on Sale of Assets | 95,276 | (95,276) | - | - | - |
| AFUDC Debt | (127,738) | | (127,738) | - | (127,738) |
| Pension Cost | 1,077,059 | | 1,077,059 | - | 1,077,059 |
| Unbilled Revenue | 4,589,307 | | 4,589,307 | - | 4,589,307 |
| Unamortized Debt Expense | 28,898 | | 28,898 | - | 28,898 |
| Bad Debts | (4,066,237) | - | (4,066,237) | - | (4,066,237) |
| Gas Research Institute | (137,379) | - | (137,379) | - | (137,379) |
| Incentive Plan | (83,619) | - | (83,619) | - | (83,619) |
| OPEB/FASB 106 | 6,610 | - | 6,610 | - | 6,610 |
| Performance Shares | (24,996) | | (24,996) | - | (24,996) |
| Vacation Accrual | 15,035 | | 15,035 | - | 15,035 |
| Environmental Clean Up Costs | (2,355,301) | | (2,355,301) | - | (2,355,301) |
| Cathodic Protection | (39,640) | | (39,640) | - | (39,640) |
| CIAC -- Deferral | 660,376 | | 660,376 | - | 660,376 |
| Depreciation Expense -- Tax | (5,494,690) | | (5,494,690) | - | (5,494,690) |
| Depreciation Expense -- Books | 5,075,925 | - | 5,075,925 | - | 5,075,925 |
| Removal Cost -- Deferral | 230,495 | | 230,495 | - | 230,495 |
| Property Tax Deferral | 2,100,000 | - | 2,100,000 | - | 2,100,000 |
| Uniform Capitalization -- Section 263 | (2,557,837) | | (2,557,837) | - | (2,557,837) |
| UNICAP -- Self-Constructed Assets | (841,404) | (841,404) | (1,682,808) | - | (1,682,808) |
| Deferred State Income Taxes | (139,241) | 139,241 | - | - | - |
| Total Timing M's | 1,498,889 | (4,285,429) | (2,786,540) | - | (2,786,540) |
| **Taxable Income** | 5,613,934 | (4,328,188) | 1,285,746 | 9,055,390 | 10,341,135 |
| Current Income Tax @ 35% | 1,964,877 | (1,514,866) | 450,011 | 3,169,386 | 3,619,397 |
| Current Accrual To Return Adjustment | (294,618) | 294,618 | - | - | - |
| Current Income Tax Expense | 1,670,259 | (1,220,248) | 450,011 | 3,169,386 | 3,619,397 |
| Deferred Income Tax Expense | (524,611) | 1,499,900 | 975,289 | - | 975,289 |
| Deferred Accrual To Return Adjustment | 303,807 | (303,807) | - | - | - |
| Deferred Income Tax Expense | (220,804) | 1,196,093 | 975,289 | - | 975,289 |
| **Total Income Tax Expense Deferred & Current** | 1,449,455 | (24,155) | 1,425,300 | 3,169,386 | 4,594,686 |

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Utility Operations Interest Deduction

| | | |
|---|---|---|
| Rate Base Proposed | EN 2-4 | 148,037,338 |
| Long Term Debt | EN 3-1 | 3.51% |
| Interest Deduction | | 5,196,111 |

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Balance Sheet
## Schedule 2A - Assets & Deferred Charges

| | 12 Months Ending June 30, 2007 | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 | Test Year Ave. of Monthly Balance |
|---|---|---|---|---|
| Gas Plant | | | | |
| In Service | 270,444,136 | 263,405,591 | 242,115,488 | 256,048,074 |
| Construction Work in Progress (non-interest bearing) | 8,823,224 | 9,472,013 | 16,225,608 | 8,454,008 |
| Less: Reserve for Depreciation | (91,758,737) | (88,448,612) | (82,053,086) | (85,706,171) |
| Total Gas Plant | 187,508,623 | 184,428,992 | 176,288,010 | 178,795,911 |
| Other Property | | | | |
| Plant - Other | | | | |
| Non Operating Property | 146,949 | 146,949 | 146,949 | 146,949 |
| Less Reserve for Depreciation | (108,128) | (105,109) | (98,702) | (102,090) |
| Total Other & Non Operating Plant | 38,821 | 41,840 | 48,247 | 44,859 |
| Investments | | | | |
| Investments in Affiliated Companies | | | | |
| Other Investments | 1 | 1 | 183 | 1 |
| Total Investments | 1 | 1 | 183 | 1 |
| Current Assets | | | | |
| Special Deposits | - | - | 10,433 | - |
| Accounts Receivable - Customer | 19,552,428 | 16,154,168 | 20,583,146 | 16,485,348 |
| Accounts Receivable - Other | 280,804 | 1,426,766 | 1,848,978 | 168,969 |
| Accounts Receivable from Assoc. Companies | 676,800 | 147,188 | 1,637,176 | 1,219,154 |
| Accum Provision for Uncollectible Accounts | (3,438,315) | (2,041,104) | (2,395,604) | (3,771,645) |
| Fuel Stock | 5,379,696 | 20,753,378 | 18,472,896 | 16,231,647 |
| Prepayments | 4,568,069 | 570,708 | 464,721 | 1,868 |
| Accrued Utility Revenues | 3,384,626 | 11,824,690 | 17,865,662 | 3,073,762 |
| Misc Current Assets | (2,141,915) | 1,884,973 | 11,500,837 | (2,814,114) |
| Total | 28,262,192 | 50,720,766 | 69,988,244 | 30,594,990 |
| Deferred Charges | | | | |
| Other Regulatory Assets | 6,809,826 | 18,528,274 | 395,915 | 3,611,177 |
| Clearing Accounts | 39,516 | - | - | (8,992) |
| Temporary Facilities | 1,479,242 | 1,418,006 | 1,415,560 | 1,364,417 |
| Misc. Deferred Debts | 123,885,084 | 162,533,563 | 136,473,871 | 159,781,774 |
| Deferred Losses from Disposition of Utility Plant | 718,896 | 108,401 | 8,539,215 | 9,423,192 |
| Accumulated Deferred Income Taxes - Asset | - | - | 1,186,523 | 1,186,523 |
| Total Deferred Charges | 132,932,564 | 182,588,244 | 148,011,084 | 175,358,092 |
| Total Assets & Deferred Charges | 348,742,202 | 417,779,844 | 394,335,767 | 384,793,853 |

**ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH**
**Balance Sheet**
**Schedule 2B - Stockholders Equity & Liabilities**

| | 12 Months Ending June 30, 2007 | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 | Test Year Ave. of Monthly Balance |
|---|---|---|---|---|
| Capitalization | | | | |
| Common Stock | (3,000,000) | (3,000,000) | (3,000,000) | (3,000,000) |
| Other Paid in Capital | (220,653,012) | (220,653,012) | (220,653,012) | (220,653,012) |
| Retained Earnings | 47,499,253 | 51,448,608 | 54,169,141 | 50,393,339 |
| Accum Other Comprehensive Income | 5,575,550 | 6,119,673 | 2,203,543 | 2,203,543 |
| Total | (170,578,210) | (166,084,732) | (167,280,328) | (171,056,130) |
| Long Term Debt | | | | |
| LTD - Notes to Assoc Comp. | (40,000,000) | (40,000,000) | (40,000,000) | (40,000,000) |
| Total | (40,000,000) | (40,000,000) | (40,000,000) | (40,000,000) |
| Current & Accrued Liabilities | | | | |
| Notes Payable | - | - | - | - |
| Accounts Payable | (12,717,214) | (34,592,583) | (23,701,106) | (7,726,425) |
| Accounts Payable - Affiliated Companies | (10,407,459) | (25,774,469) | (21,584,017) | (23,523,032) |
| Notes Payable - Affiliated Companies | (36,526,804) | (40,153,808) | (53,739,311) | (38,546,047) |
| Customer Deposits | (236,932) | (166,240) | (226,069) | (178,864) |
| Interest Accrued | (30,960) | (27,125) | (76,814) | (78,809) |
| Other Tax Liabilities | (1,268,282) | (1,843) | 110,859 | (407,466) |
| Misc. Accrued Liabilities | (1,110,624) | (84,870) | (1,005,303) | (1,150,669) |
| Total | (62,298,274) | (100,800,938) | (100,221,761) | (71,611,314) |
| Deferred Credits | | | | |
| Other Deferred Credits | (4,724,960) | (7,778,997) | (2,558,496) | (2,985,357) |
| Other Regulatory Liabilities | (1,573,048) | (37,149,447) | (13,783,002) | (31,092,764) |
| Accum Deferred Income Taxes - Liab | (34,274,135) | (38,787,067) | (39,486,683) | (39,185,200) |
| Total | (40,572,143) | (83,715,511) | (55,828,182) | (73,263,322) |
| Reserves | | | | |
| Accum Provision for Pension & OPEB's | (9,199,538) | 697,275 | 2,061,083 | 1,173,023 |
| Accum Misc. Operating Provisions | (26,094,037) | (27,875,938) | (33,066,579) | (30,036,111) |
| Total | (35,293,574) | (27,178,662) | (31,005,496) | (28,863,088) |
| Total Equity & Liabilities | (348,742,202) | (417,779,844) | (394,335,767) | (384,793,853) |

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Balance Sheet
Schedule 2C - Materials & Supplies

| | 12 Months Ending June 30, 2007 | First Preceding Fiscal Year Ending Dec 31, 2006 | Second Preceding Fiscal Year Ending Dec 31, 2005 | Test Year Ave. of Monthly Balance |
|---|---|---|---|---|
| Gas Inventories | | | | |
| LPG | 1,143,159 | 1,578,217 | 1,404,242 | 1,494,953 |
| LNG | 58,544 | 82,061 | 88,562 | 76,482 |
| Other - Natural Gas | 4,177,992 | 19,093,100 | 16,980,092 | 14,660,193 |
| | 5,379,696 | 20,753,378 | 18,472,896 | 16,231,628 |

# National Grid NH
## Rate Design Filing
## Report of Proposed Rate Changes-Permanent Rates



| | | RESIDENTIAL | | | C & I High Winter Use | | | C & I Low Winter Use | | | | | Combined |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Puc 1604.02 (a)(2) | Non-Heat | Heat | Low Income (After Discount) | Small High Winter Use | Med High Winter Use | Large High Winter Use | Small Low Winter Use | Med Low Winter Use | Large Load Factor <90% | Large Load Factor <110% | Large Load Factor >110% | Large Load Factor >90% |
| 1 | a. Rate Class Designation | RNSH | RSH | RLIAP | SH | MH | LH | SL | ML | LLL90 | LLL110 | LLG110 | LLG90 |
| 2 | | R-1 | R-3 | R-4 | G-41 | G-42 | G-43 | G-51 | G-52 | G-53 | G-54 | G-63 | G-63 |
| 3 | b. Effect of Proposed Change | | | | | | | | | | | | |
| 4 | Increase (Decrease) | $ 164,819 | $5,327,534 | $ 183,897 | $ 1,165,682 | $1,183,221 | $ 267,004 | $ 54,235 | $ 142,302 | $ 317,377 | $ 6,718 | $ 259,378 | $ 266,329 |
| 5 | | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | | |
| 7 | c. Average Number of Customers | 4,975 | 63,221 | 4,530 | 7,277 | 1,464 | 43 | 300 | 43 | 38 | 1 | 16 | 17 |
| 8 | | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | |
| 10 | d. Estimated Annual Revenue | | | | | | | | | | | | |
| 11 | Present Rates | 1,946,667 | 83,205,785 | 4,973,714 | 27,265,040 | 42,206,428 | 6,930,198 | 5,473,436 | 8,374,193 | 11,427,237 | 258,391 | 14,072,584 | 14,330,975 |
| 12 | Proposed Rates | 2,111,486 | 88,533,319 | 5,157,611 | 28,430,722 | 43,389,649 | 7,197,203 | 5,527,670 | 8,516,494 | 11,744,615 | 265,108 | 14,331,962 | 14,597,303 |
| 13 | | | | | | | | | | | | | |
| 14 | e. Proposed Rates, $/bill | | | | | | | | | | | | |
| 15 | Present Rates | $ 32.61 | $ 109.68 | $ 91.50 | $ 312.21 | $ 2,402.23 | $ 13,573.54 | $ 1,521.82 | $16,401.76 | $24,859.83 | $20,894.25 | $ 73,498.82 | $ 70,307.29 |
| 16 | Proposed Rates | $ 35.37 | $ 116.70 | $ 94.88 | $ 325.56 | $ 2,469.57 | $ 14,096.50 | $ 1,536.90 | $16,680.48 | $25,550.28 | $21,437.45 | $ 74,853.51 | $ 71,613.89 |
| 17 | Increase (Decrease) | $ 2.76 | $ 7.02 | $ 3.38 | $ 13.35 | $ 67.34 | $ 522.96 | $ 15.08 | $ 278.71 | $ 690.45 | $ 543.20 | $ 1,354.69 | $ 1,306.60 |
| 18 | Percentage Increase (Decrease) | 8.47% | 6.40% | 3.70% | 4.28% | 2.80% | 3.85% | 0.99% | 1.70% | 2.78% | 2.60% | 1.84% | 1.86% |

NOTES:

Data above imputes gas supply costs for transportation customers equal to COG rates for both present and proposed rates.
Analysis above reflects the impact on COG and LDAC rates for conversion from wet to dry therm billing.

ORIGINAL
DG 08-009
Exhibit No. # 30
Witness

## TABLE OF CONTENTS (Cont'd)

II **RATE SCHEDULES** Page No.

# I. GENERAL TERMS AND CONDITIONS

## 1 - SERVICE AREA

1(A) Service Area. The area authorized to be served by the Company and to which this tariff applies are the following cities and towns: Allenstown, Amherst, Auburn, Bedford, Belmont, Berlin, Boscawen, Bow, Concord, Derry, Franklin, Gilford, Goffstown, Hollis, Hooksett, Hudson, Laconia, Litchfield, Londonderry, Loudon, Manchester, Merrimack, Milford, Nashua, Northfield, Pembroke, Sanbornton, Tilton and part of Canterbury and Winnesquam.

## 2 - GENERAL TERMS AND CONDITIONS

2(A) Filing. A copy of this tariff is on file with the New Hampshire Public Utilities Commission and is open to inspection at the offices of the Company.

2(B) Revisions. This tariff may be revised, amended, supplemented, or otherwise changed from time to time in accordance with the rules of the New Hampshire Public Utilities Commission and such changes, when effective, shall have the same force as the original tariff.

2(C) Application. The tariff provisions apply to everyone lawfully receiving gas supply service and/or delivery-only service from the Company under the rates herein and receipt of gas service shall constitute the receiver a customer of the Company as the term is used herein whether service is based upon contract, agreement, accepted signed application, or otherwise.

2(D) Statement by Agents. No representative has the authority to modify a tariff rule or provision or to bind the Company by a promise or representation contrary thereto.

2(E) No Prejudice of Rights. The failure of the Company to enforce any of the terms of this tariff shall not be deemed a waiver of its right to do so.

2(F) Gratuities to Employees. The Company's employees are strictly forbidden to demand or accept any personal compensation or gifts for service rendered by them while working for the Company on the Company's time.

2(G) Advance Payments. Payments to the Company for charges provided in these rules and regulations to be borne by the customer shall be made in advance.

2(H) Assignment. Subject to the rules and regulations, all contracts by the Company shall be binding upon, and oblige, and continue for the benefit of, the successors and assigns, heirs, executors, and administrators of the parties hereto.

# I. GENERAL TERMS AND CONDITIONS

## 7 - SERVICE AND MAIN EXTENSIONS

7(A) Upon receipt of an application from a prospective Customer setting forth the location of the premises to be served, the extent of the service to be required and any other pertinent information requested by the Company, the Company will advise the Customer of the type and character of the service it will furnish, under the applicable tariff, and if required, the location of the Company's metering and related equipment. The Company will have sole reasonable discretion on the location of meters and other related equipment. Upon request, the Company will furnish detailed information describing the connections necessary between the Company's facilities and the Customer's premises and Customer and Company responsibilities for installation of facilities.

7(B) An application for service will not be approved until the Customer has delivered to the Company a fully completed request for service form and the Company has determined that an adequate flow of Gas can be delivered to the Customer's Delivery Point under normal operating conditions.

7(C) Whenever the estimated expenditures necessary to supply Gas to a Customer or to resume service to a Customer after a discontinuance of service for over twelve (12) months, for reasons other than the needs of the Company, shall be of such an amount that the income to be derived from gas service at the applicable rates will, in the opinion of the Company, be insufficient to warrant such expenditures, the Company may, in addition to the payments for Gas under the applicable rates, require the Customer to pay the whole or a part of such expenditures, or make such other reasonable payments as the Company may deem necessary.

7(D) The Company reserves the right to reject any application for service if the amount or nature of the service applied for, or the distance of the premises to be served from existing, suitable gas distribution facilities, or the difficulty of access thereto is such that the estimated income from the service applied for is insufficient to yield a reasonable return to the Company, unless such application is accompanied by a cash payment or an undertaking satisfactory to the Company guaranteeing a stipulated revenue for a definite period of time, or both.

**PROVISIONS DELETED**
**RESERVED FOR FUTURE USE**

**PROVISIONS DELETED**
**RESERVED FOR FUTURE USE**

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# I. GENERAL TERMS AND CONDITIONS

## 16 - COST OF GAS CLAUSE

(16) **Summer Season** – The calendar months May 1 through October 31.
(17) **Off-System Sales Margin** - The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.
(18) **Winter Commodity** - The gas supplies procured by the Company to serve firm load in the Winter Season.
(19) **Winter Demand** - Gas supply demand, peaking demands, storage and transmission capacity procured by the Company to service firm load in the Winter Season.
(20) **Winter Season** – The calendar months November 1 through April 30.
(21) **PR Allocator** – The percentage of annual capacity charges assigned to the Winter Season calculated using the Proportional Responsibility Method.
(22) **Purchased Gas Working Capital** - The allowable working capital derived from Winter Season and Summer Season demand and commodity related costs.

### 16(F) Approved Cost

The Cost of Gas calculation utilizes information periodically established by the NHPUC. The table below lists the approved costs factors:

| Variable | Description | Approved Figure |
|---|---|---|
| MISC | Miscellaneous Overhead | $56,975 |
| PS | Production and Storage Capacity | $1,869,226 |
| WCA% | Working Capital Allowance Percentage | 0.522% |
| BD% | Bad Debt Percentage | 2.509% |

### 16(G) Cost of Gas (COG) Calculations by Customer Class

The Cost of Gas (COG) Formula shall be computed on a semiannual basis for three (3) groups of customer classes as shown on the following table. The computation will use forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts shall be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

The COG for the Residential rate classes shall represent the total system average unit cost of gas of meeting firm sales load, projected in each COG filing. The Commercial & Industrial (C&I) Low Winter (LW) and High Winter (HW) rates will be calculated in the following way: first, the demand unit cost of gas, the sum of purchased and stored gas demand costs divided by projected prorated sales, will be multiplied by the applicable load factor ratio and then multiplied by the correction factor. This adjusted demand factor will then be added to the commodity factor, adjustment factor and indirect cost of gas rate to determine the total COG rates for the C&I LW and HW rate classes. The two load factor ratios shall be derived once a year, for effect every November 1 through October 31, using the ratio of the unit capacity cost of each C&I group to the total system unit capacity cost that is determined in the Company's submittal of its Capacity Allocators, for Capacity Assignment purposes, filed with its Winter COG, and as presented in Attachment F of the Delivery Service Terms and Conditions. The Correction Factor aligns the peak day volumes used to calculate the load factor ratios with the seasonal throughput volumes applied to the COG calculations.

| GROUP | CUSTOMER CLASSES |
|---|---|
| Residential | Residential Heating and Non-Heating |
| Commercial and Industrial: Low Winter Use | G-51, G-52 G-53, and G-54 |
| Commercial and Industrial: High Winter Use | G-41, G-42 and G-43 |

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Nickolas Stavropoulos
Title: President

# I. GENERAL TERMS AND CONDITIONS

## 18. LOCAL DELIVERY ADJUSTMENT CLAUSE

**Section**



### 18(A) Purpose

The purpose of the Local Delivery Adjustment Clause ("LDAC" or this "Clause") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges ("CC"), Winter Period Surcharges ("WPS"), Environmental Surcharges ("ES") including the Relief Holder Surcharge ("RHS") and the Manufactured Gas Program Surcharge ("MGP"), to return interruptible transportation margin credits ("ITMC"), recover gas restructuring expenses ("GRE"), rate case expenses ("RCE"), Residential Low Income Assistance Program costs ("RLIAP") and any other expenses the NHPUC may approve from time to time.

### 18(B) Applicability

This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers as shown on the table below. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 18-(L) "Other Rules."

| *Applicability* | *CC 18(C)* | *ES 18(D)* | *ITMC 18(E)* | *GRE 18(F)* | *RCE 18(G)* | *RLIAP 18(H)* | *PRAF 18(I)* |
|---|---|---|---|---|---|---|---|
| Residential Non-Space Heating – R-1, | 1 | X | X | N/A | 1 | X | X |
| Residential Space Heating – R-3, R-4 | 1 | X | X | N/A | 1 | X | X |
| Small C&I – G-41, G-51 | 1 | X | X | X | 1 | X | X |
| Medium C&I – G-42, G-52 | 1 | X | X | X | 1 | X | X |
| Large C&I – G-43, G-53, G-54 | 1 | X | X | X | 1 | X | X |

Notes:
N/A Not applicable
X Applicable to all
1 As ordered by the NHPUC

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# I. GENERAL TERMS AND CONDITIONS

## 18. LOCAL DELIVERY ADJUSTMENT CLAUSE

**18(H)(6) Reconciliation Adjustments**

Prior to the Company's peak season Cost of Gas filing, the Company will calculate the difference between (a) the revenue derived by multiplying the actual firm sales and delivery service throughput by the RLIAP Rate through October 31st, and (b) the actual costs of the program which consists of (1) the revenue shortfall calculated by applying the actual billing determinants of the RLIAP classes to the difference in the regular and reduced residential base rates in effect for the annual reconciliation period and (2) the start-up, administrative and marketing costs associated with the implementation of the program, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates. The combined costs will then be recorded in the deferred RLIAP account 175.39. The Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

**18(I) Pension Costs and Post-Retirement Benefits Other Than Pensions Allowable for the LDAC**

**18(I)(1) Purpose**

The Purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to reconcile pension and post-retirement benefits other than pensions ("PBOP") expense amounts included in the Company's distribution rates with the total expense amounts booked by the Company pursuant to FAS 87 and FAS 106 and as amended by FAS 158.

**18(I)(2) Applicability**

The Pension and Post Retirement Benefits Other than Pensions Reconciliation Adjustment Factor ("PRAF") shall be applied to all firm sales and transportation tariff customers. The PRAF shall be filed with the Company's peak season Cost of Gas Clause filing and shall be calculated annually by the Company and be subject to review and approval by the Commission.

**18(I)(3) Effective Date**

On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the PRAF applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

**18(I)(4) Pension and PBOP Costs Allowable for LDAC**

The costs to be recovered shall be comprised of all the pension costs associated with the Company's Pension Plans as determined by SFAS-87 and all of the PBOP costs as determined by SFAS-106 (and as amended by FAS 158) and as approved by the NHPUC that have not yet been included in the Company's distribution rates plus associated carrying charges.

# I. GENERAL TERMS AND CONDITIONS

## 18. LOCAL DELIVERY ADJUSTMENT CLAUSE

### 18(I)(5) PRAF Formula

$$PRAF_x = \frac{RA_x + cc(URD_x - DTA_x) + PPRA_x}{A{:}TPvol}$$

**Where:**

PRAF = The annual Pension/PBOP Reconciliation Adjustment Factor.

$RA_x$ = The Reconciliation Adjustment for $Year_x$ is one-third of the Unamortized Reconciliation Deferral at the end of the Prior Year.

cc = The Cost of Capital is the tax-effected weighted-average cost of capital as allowed by the NHPUC in the Company's most recent rate case.

$URD_x$ = The Unamortized Reconciliation Deferral is the amount of the Reconciliation Deferral not yet included in distribution rates. At the beginning of $Year_x$ the Unamortized Reconciliation Deferral is the sum of: (1) the Unamortized Reconciliation Deferral at the beginning of the Prior Year; plus (2) the Reconciliation Deferral for the Prior Year; minus (3) the Reconciliation Adjustment for the Prior Year.

$DTA_x$ = The Deferred Tax Amount is the deferred taxes associated with the Pre-Paid Amount and the URD at the end of the Prior Year.

$PPRA_x$ = The Past Period Reconciliation Amount is (a) the difference between: (1) the amount of PRAF revenue that should have been collected in the Prior Year; and (2) the amount of PRAF revenue actually received by the Company in the Prior Year and (b) the amount computed in the clause (a) times the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

A:TPvol = Annual forecasted throughput volumes inclusive of all sales and transportation throughput.

x = The current year.

### 18(J) Effective Date of Local Delivery Adjustment Clause

The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

### 18(K) Local Delivery Adjustment Clause Formulas

The LDAC shall be calculated on an annual basis, by customer, by summing up the various factors included in the LDAC, where applicable.

# I. GENERAL TERMS AND CONDITIONS

## 18. LOCAL DELIVERY ADJUSTMENT CLAUSE

**LDAC Formula**

$LDAC^X = CC^X + ES - ITMC + GREF^x + RCE^x + RLIAP + PRAF$

**And:**

$ES^X = RHS + MGP$

**Where:**

| | |
|---|---|
| $LDAC^X$ | Annualized class specific Local Delivery Adjustment Charge. |
| $CC^X$ | Annualized class specific CC or EE Charge. |
| ITMC | Annualized Interruptible Transportation Margin Credit. |
| ES | Total firm annualized ES. |
| RHS | Annualized charge to recover the costs of the closure of the Relief Holder at Gas Street, Concord, NH |
| MGP | Annualized charge to cover the remediation costs related to former manufactured gas plants. |
| $GREF^x$ | Total firm annualized class specific Gas Restructuring Expense Factor. |
| $RCE^x$ | Class specific Rate Case Expense Factor. |
| RLIAP | Residential Low Income Assistance Program Rate |
| PRAF | Pension costs and Post Retirement Benefits Other Than Pensions Adjustment Factor |

**18(L) Application of LDAC to Bills**

The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 18(B).

**18(M) Other Rules**

(1) The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.
(2) Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.
(3) The Company may implement an amended LDAC with the NHPUC approval at any time.
(4) The NHPUC may, at any time, require the Company to file an amended LDAC.
(5) The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.

**18(N) Amendments To Uniform System Of Accounts**

**175.42 Interruptible Transportation Margin Reconciliation Adjustment for LDAC**

This account shall be used to record the cumulative difference between annual Interruptible Transportation margin returns and annual Interruptible Transportation margins. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Clause, 18(E).

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Nickolas Stavropoulos
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# I. GENERAL TERMS AND CONDITIONS

## 18. LOCAL DELIVERY ADJUSTMENT CLAUSE

**175.85 Gas Restructuring Expense Reconciliation Adjustment`**
This account shall be used to record the cumulative difference between the recovery and actual amounts of third party incremental expenses associated with the Company's Gas Restructuring initiatives. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Clause, 18(F).

**175.22 Demand-Side Management and/or Energy Efficiency Reconciliation Adjustment**

This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Clause, 18(C).

**175.90 Environmental Response Costs Reconciliation Adjustment**

This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Clause, 18(D).

**175.65 Rate Case Expense Reconciliation Adjustment**

This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(G).

**175.39 Residential Low Income Assistance Program Reconciliation Adjustment**

This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the RLIAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 18(H).

**175.__Pension and PBOP Expense Reconciliation Adjustment**

This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the PRAF rate and the total pension and PBOP expense amounts booked by the Company in the prior year.

# I. GENERAL TERMS AND CONDITIONS

## 19 - SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY (Cont'd)

### PRIORITIES

Firm rate customers shall be serviced according to the following preference categories with the first and each succeeding category having preference over the succeeding categories

1) Company use for fuel and lost and unaccounted for

2) Firm sales or transportation service for high priority residential uses including apartment buildings and other multi-unit buildings, small commercial establishments using less than 50 DT on a peak day, schools, hospitals, police protection, fire protection, sanitation facilities and correctional facilities

3) Firm sales or transportation service for essential agricultural uses, as defined by the Secretary of Agriculture, for full food and natural fiber production, process and feedstock use for fertilizer and agricultural chemicals, process and feedstock for animal feeds and food, food quality maintenance, food packaging, marketing and distribution for food related products and on farm uses

4) Firm sales or transportation service for large commercial requirements (50 DT or more on a peak day), firm industrial requirements for plant protection, feedstock and process needs and firm industrial sales up to 300 DT per day

5) Firm sales or transportation service for all industrial requirements not specified in (2), (3), (4), (5), (6) (7), (10) or (11), including the firm period of 280 Day sales or transportation

6) Firm sales or transportation service including the firm period of 280 Day sales or transportation or transportation for industrial requirements for boiler fuel use at less than 1,500 DT per day, but more than 300 DT per day, where alternate fuel capabilities can meet such requirements

7) Firm sales or transportation service including the firm period of 280 Day sales or transportation or transportation for industrial requirements for large volume (1,500 DT or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements

8) Interruptible sales or transportation service and the non-firm period of 280 Day sales or transportation.

### STORAGE INJECTION

Within each category, storage injection required to meet the needs of higher priorities may be given preference over all other uses within that category.

### PENALTY

For all unauthorized volumes of gas taken by a customer, the customer shall pay the Company a penalty of five times the daily index for each therm taken. Such penalty shall be added to the regular rates in effect. The Company shall have the right, without obligation, to waive any penalty for unauthorized use of gas, if on the day when the penalty was incurred deliveries to other of the Company's customers were not adversely affected. Continued unauthorized use, at the sole discretion of the Company, may result in termination of service.

## II. RATE SCHEDULES

### Residential Non Heating Rate
### Classification No. R-1

Availability
This rate is available to all residential customers who do not have gas space heating equipment. Available for use which is separately metered and billed for each dwelling unit. Availability is limited to use in locations served by the Company's mains and for which the Company's facilities are adequate.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | $0.4583 per day | or | $13.75 | per 30 day month |
| Winter Period | | | | |
| First 10* therms per 30 day month at | | | $0.0228 | per therm |
| All over 10 therms per 30 day month at | | | $0.0201 | per therm |
| Summer Period | | | | |
| First 10* therms per 30 day month at | | | $ $0.0228 | per therm |
| All over 10 therms per 30 day month at | | | $0.0201 | per therm |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated billwill be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

## Residential Heating Rate
## Classification No. R-3

Availability
This rate is for all residential use for those domestic customers who use gas as the principal household heating fuel. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company's facilities are adequate.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | $0.6583 per day | or | $19.75 | per 30 day month |
| Winter Period | | | | |
| First 100 * therms per 30 day month at | | | $0.2291 | per therm |
| All over 100 therms per 30 day month at | | | $0.1331 | per therm |
| Summer Period | | | | |
| First 20 * therms per 30 day month at | | | $0.2291 | per therm |
| All over 20 therms per 30 day month at | | | $0.1331 | per therm |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

## Low Income Residential Heating Rate
## Classification No. R-4

Availability
This rate is for residential use for those domestic customers who use gas as the principal household heating fuel if any member of the household qualifies for a benefit through one of the programs listed below, subject to the qualification period described under the "Terms and Conditions" of this rate. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company facilities are adequate.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | |
|---|---|---|---|
| Customer Charge Per Meter | $0.2633 per day | or $7.90 | per 30 day month |
| Winter Period | | | |
| First 100 * therms per 30 day month at | | $0.0916 | per therm |
| All over 100 therms per 30 day month at | | $0.0532 | per therm |
| Summer Period | | | |
| First 20 * therms per 30 day month at | | $0.0916 | per therm |
| All over 20 therms per 30 day month at | | $0.0532 | per therm |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

## II. RATE SCHEDULES

## Low Income Residential Heating Rate
## Classification No. R-4
## (Continued)

Terms and Conditions
For those customers qualifying for the program this rate R-4 shall apply for a one year period. On the date that the one-year period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-4 expires, the rate on each account shall revert back to the non-low income Residential Heating Rate, R-3. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following October 31, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

# Commercial/Industrial Service
# Low Annual Use, High Winter Use
# Rate Classification G-41

Availability
This rate is available for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | $1.6667 per day | or | $50.00 | per 30 day month |
| Winter Period | | | | |
| First 100 * therms per 30 day month at | | | $0.2268 | Per therm |
| All over 100 therms per 30 day month at | | | $0.1475 | Per therm |
| Summer Period | | | | |
| First 20 * therms per 30 day month at | | | $0.2268 | Per therm |
| All over 20 therms per 30 day month at | | | $0.1475 | Per therm |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

## II. RATE SCHEDULES

## Commercial/Industrial Service
## Low Annual Use, High Winter Use
## Rate Classification G-41
## (Continued)

Terms and Conditions
U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4)days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

# Commercial/Industrial Service
# Medium Annual Use, High Winter Use
# Rate Classification G-42

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or eqaul to 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | $4.6667 per day | or | $140.00 | per 30 day month |
| Winter Period | | | | |
| First 1000 * therms per 30 day month at | | | $0.2476 | per therm |
| All over 1000 therms per 30 day month at | | | $0.1636 | per therm |
| Summer Period | | | | |
| First 400 * therms per 30 day month at | | | $0.2476 | per therm |
| All over 400 therms per 30 day month at | | | $0.1636 | per therm |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

## II. RATE SCHEDULES

### Commercial/Industrial Service
### Medium Annual Use, High Winter Use
### Rate Classification G-42
### (Continued)

Terms and Conditions
Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

### Commercial/Industrial Service
### High Annual Use, High Winter Use
### Rate Classification G-43

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | $20.0000 per day | or | $600.00 | per 30 day month |
| Winter Period | | | | |
| All therms per 30 day month at | | | $0.1649 | per therm |
| Summer Period | | | | |
| All therms per 30 day month at | | | $0.0754 | per therm |

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

## II. RATE SCHEDULES

### Commercial/Industrial Service
### High Annual Use, High Winter Use
### Rate Classification G-43
### (Continued)

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

# Commercial/Industrial Service
# Low Annual Use, Low Winter Use
# Rate Classification G-51

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | |
|---|---|---|---|
| Customer Charge Per Meter | $1.6667 per day | or $50.00 | per 30 day month |
| Winter Period | | | |
| First 100 * therms per 30 day month at | | $0.1103 | per therm |
| All over 100 therms per 30 day month at | | $0.0712 | per therm |
| Summer Period | | | |
| First 100 * therms per 30 day month at | | $0.1103 | per therm |
| All over 100 therms per 30 day month at | | $0.0712 | per therm |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

## II. RATE SCHEDULES

## Commercial/Industrial Service
## Low Annual Use, Low Winter Use
## Rate Classification G-51
## (Continued)

Terms and Conditions
Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4)days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

# Commercial/Industrial Service
# Medium Annual Use, Low Winter Use
# Rate Classification G-52

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

| | | | |
|---|---|---|---|
| Customer Charge Per Meter | $4.6667 per day | or $140.00 | per 30 day month |
| Winter Period | | | |
| First 1000 * therms per 30 day month at | | $0.1295 | per therm |
| All over 1000 therms per 30 day month at | | $0.0879 | per therm |
| Summer Period | | | |
| First 1000 * therms per 30 day month at | | $0.0952 | per therm |
| All over 1000 therms per 30 day month at | | $0.0548 | per therm |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

## II. RATE SCHEDULES

## Commercial/Industrial Service
## Medium Annual Use, Low Winter Use
## Rate Classification G-52
## (Continued)

**Terms and Conditions**

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

# Commercial/Industrial Service
# High Annual Use, Load Factor Less Than 90%
# Rate Classification G-53

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage less than 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | |
|---|---|---|---|
| Customer Charge Per Meter | $20.00 per day | $600.00 | per month |
| Winter Period<br>All therms per month at | | $0.1116 | per therm |
| Summer Period<br>All therms per month at | | $0.0534 | per therm |

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

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## II. RATE SCHEDULES

## Commercial/Industrial Service
## High Annual Use, Load Factor Less Than 90%
## Rate Classification G-53
## (Continued)

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

## Commercial/Industrial Service
## High Annual Use, Load Factor Greater Than 90%
## Rate Classification G-54

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage greater than or equal to 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | |
|---|---|---|---|
| Customer Charge Per Meter | $20.00 per day | $600.00 | per month |
| Winter Period<br>All therms per month at | | $0.0374 | per therm |
| Summer Period<br>All therms per month at | | $0.0202 | per therm |

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

## II. RATE SCHEDULES

# Commercial/Industrial Service
# High Annual Use, Load Factor Greater Than 90%
# Rate Classification G-54
# (Continued)

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

**PROVISIONS DELETED**
**RESERVED FOR FUTURE USE**

**PROVISIONS DELETED**
**RESERVED FOR FUTURE USE**

**II. RATE SCHEDULES**

## OUTDOOR GAS LIGHTING

Availability
This rate is available for residential outdoor gas lighting where such service is provided from the Company's existing delivery system to a standard gas light fixture or fixtures, located on the customer's premises, and when it is not feasible to meter such service along with other gas used on the premises and bill the same under the rate in effect for all other services.

Rate Per Light Per Month $10.50

The above rates shall be adjusted to reflect the recovery of all applicable taxes.

Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a location, an account charge is incurred in addition to all other charges. The account charge is $20.00 when the visit to the location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Meters are read and bills are presented monthly.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

# STANDBY SERVICE

Availability
This service is available to commercial and industrial sales customers with a minimum of 5 MMBtu per hour connected load who have alternative fuel burning capability and who require that the Company maintain facilities and supply availability to provide natural gas service upon twenty-four (24) hour notice to the Company, and who have had a load factor of less than 15% determined by dividing the customer's consumption during the prior twelve (12) months by connected load times twenty-four (24) hours x 365 days and multiplying the result by 100%.

Character of Service
Standby service is for customers with alternative fuel supply availability who require the Company to supply natural gas on short notice. The charge hereunder is for the purpose of defraying the fixed costs associated with maintaining readiness to serve, including, but not limited to, the capital cost and cost of maintaining services, regulators, as well as the cost of system capacity, supplier demand charges and other supply capability on a continuous basis.

Rate

| Customer Charge Per Month | Winter $ Per Therm | Summer $ Per Therm | Demand per MMBtu/hr. MMBtu/hr. Connected Load |
|---|---|---|---|
| $40.00 | $0.5912 | $0.4512 | $150.00 |

In any month during which consumption exceeds connected load times twenty-four (24) hours x five (5) days the charge for service will be made under the customer's otherwise applicable tariff. The applicable Standby charge shall be the minimum bill in those months when gas flows. Standby service may be taken in conjunction with seasonal service. The seasonal service gas will be separately metered and the seasonal service meter will be locked during the non-seasonal service months unless a standby contract has been signed. This rate is not subject to the cost of gas rate. This rate is not available in conjunction with 280 day service.

The above rates shall be adjusted to reflect the recovery of all applicable taxes.

The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Terms and Conditions
To be eligible for standby service, a customer must sign a contract for a minimum of the five (5) winter months of November through April. Bills will be presented at the first of each month. Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

## II RATE SCHEDULES
### FIRM RATE SCHEDULES

| | Winter Period | | | | Summer Period | | | |
|---|---|---|---|---|---|---|---|---|
| | Delivery Charge | Cost of Gas Rate Page 84 | LDAC Page 91 | Total Rate | Delivery Charge | Cost of Gas Rate Page 84 | LDAC Page 91 | Total Rate |
| **Residential Non Heating - R-1** | | | | | | | | |
| Customer Charge per Month per Meter | $13.75 | | | $ 13.75 | $13.75 | | | $ 13.75 |
| Size of the first block | 10 therms | | | | 10 therms | | | |
| Therms in the first block per month at | $ 0.0228 | $ 1.1337 | $ 0.0184 | $ 1.1749 | $ 0.0228 | $ 0.9556 | $ 0.0381 | $ 1.0165 |
| All therms over the first block per month at | $ 0.0201 | $ 1.1337 | $ 0.0184 | $ 1.1722 | $ 0.0201 | $ 0.9556 | $ 0.0381 | $ 1.0138 |
| **Residential Heating - R-3** | | | | | | | | |
| Customer Charge per Month per Meter | $19.75 | | | $ 19.75 | $19.75 | | | $ 19.75 |
| Size of the first block | 100 therms | | | | 20 therms | | | |
| Therms in the first block per month at | $ 0.2291 | $ 1.1337 | $ 0.0189 | $ 1.3817 | $ 0.2291 | $ 0.9556 | $ 0.0387 | $ 1.2234 |
| All therms over the first block per month at | $ 0.1331 | $ 1.1337 | $ 0.0189 | $ 1.2857 | $ 0.1331 | $ 0.9556 | $ 0.0387 | $ 1.1274 |
| **Residential Heating - R-4** | | | | | | | | |
| Customer Charge per Month per Meter | $7.90 | | | $ 7.90 | $ 7.90 | | | $ 7.90 |
| Size of the first block | 100 therms | | | | 20 therms | | | |
| Therms in the first block per month at | $ 0.0916 | $ 1.1337 | $ 0.0189 | $ 1.2442 | $ 0.0916 | $ 0.9556 | $ 0.0387 | $ 1.0859 |
| All therms over the first block per month at | $ 0.0532 | $ 1.1337 | $ 0.0189 | $ 1.2058 | $ 0.0532 | $ 0.9556 | $ 0.0387 | $ 1.0475 |
| **Commercial/Industrial - G-41** | | | | | | | | |
| Customer Charge per Month per Meter | $50.00 | | | $ 24.64 | $26.00 | | | $ 26.00 |
| Size of the first block | 100 therms | | | | 20 therms | | | |
| Therms in the first block per month at | $ 0.2268 | $ 1.1337 | $ 0.0099 | $ 1.3704 | $ 0.2268 | $ 0.9583 | $ 0.0336 | $ 1.2187 |
| All therms over the first block per month at | $ 0.1475 | $ 1.1337 | $ 0.0099 | $ 1.2911 | $ 0.1475 | $ 0.9583 | $ 0.0336 | $ 1.1394 |
| **Commercial/Industrial - G-42** | | | | | | | | |
| Customer Charge per Month per Meter | $140.00 | | | $140.00 | $140.00 | | | $ 140.00 |
| Size of the first block | 1000 therms | | | | 400 therms | | | |
| Therms in the first block per month at | $ 0.2476 | $ 1.1337 | $ 0.0099 | $ 1.3912 | $ 0.2476 | $ 0.9583 | $ 0.0336 | $ 1.2395 |
| All therms over the first block per month at | $ 0.1636 | $ 1.1337 | $ 0.0099 | $ 1.3072 | $ 0.1636 | $ 0.9583 | $ 0.0336 | $ 1.1555 |
| **Commercial/Industrial - G-43** | | | | | | | | |
| Customer Charge per Month per Meter | $600.00 | | | $ 299.39 | $600.00 | | | $ 600.00 |
| All therms over the first block per month at | $ 0.1649 | $ 1.1337 | $ 0.0099 | $ 1.3085 | $ 0.0754 | $ 0.9583 | $ 0.0336 | $ 1.0673 |
| **Commercial/Industrial - G-51** | | | | | | | | |
| Customer Charge per Month per Meter | $50.00 | | | $ 24.81 | $50.00 | | | $ 50.00 |
| Size of the first block | 100 therms | | | | 100 therms | | | |
| Therms in the first block per month at | $ 0.1103 | $ 1.1336 | $ 0.0099 | $ 1.2538 | $ 0.1103 | $ 0.9537 | $ 0.0336 | $ 1.0976 |
| All therms over the first block per month at | $ 0.0712 | $ 1.1336 | $ 0.0099 | $ 1.2147 | $ 0.0712 | $ 0.9537 | $ 0.0336 | $ 1.0585 |
| **Commercial/Industrial - G-52** | | | | | | | | |
| Customer Charge per Month per Meter | $140.00 | | | $ 69.29 | $140.00 | | | $ 140.00 |
| Size of the first block | 1000 therms | | | | 1000 therms | | | |
| Therms in the first block per month at | $ 0.1295 | $ 1.1336 | $ 0.0099 | $ 1.2730 | $ 0.0952 | $ 0.9537 | $ 0.0336 | $ 1.0825 |
| All therms over the first block per month at | $ 0.0879 | $ 1.1336 | $ 0.0099 | $ 1.2314 | $ 0.0548 | $ 0.9537 | $ 0.0336 | $ 1.0421 |
| **Commercial/Industrial - G-53** | | | | | | | | |
| Customer Charge per Month per Meter | $600.00 | | | $ 300.00 | $600.00 | | | $ 600.00 |
| All therms over the first block per month at | $ 0.1116 | $ 1.1336 | $ 0.0099 | $ 1.2551 | $ 0.0534 | $ 0.9537 | $ 0.0336 | $ 1.0407 |
| **Commercial/Industrial - G-54** | | | | | | | | |
| Customer Charge per Month per Meter | $600.00 | | | $ 300.00 | $600.00 | | | $ 600.00 |
| All therms over the first block per month at | $ 0.0374 | $ 1.1336 | $ 0.0099 | $ 1.1809 | $ 0.0202 | $ 0.9537 | $ 0.0336 | $ 1.0075 |

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Effective: August 24, 2008

Issued: By N. Stavropoulos
Nickolas Stavropoulos
Title: President

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## II. RATE SCHEDULES

## 280 DAY TRANSPORTATION SERVICE (Cont'd)

Terms and Conditions

Customers taking service under this rate schedule will be subject to the terms and conditions of Delivery Service, Section 9 - Daily Metered Delivery Service, of the Company's Delivery Tariff.

A written 280 Day service agreement (Service Agreement) on the Company's standard form for a minimum period, as defined in the Service Agreements, shall be required for 280 Day service. The Company will make service available under this tariff within sixty (60) days of receipt of the completed Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily or monthly consumption, provisions for notice of interruption and additional charges for excess usage, terms of payment and other terms and conditions of service.

Customer shall pay its bills monthly. Any amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed, are subject to a late payment charge of one and one half percent (1½%) per month on the unpaid balance.

It is the customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times.

The customer must certify in a signed affidavit, appended to the contract, that the installation being served is physically and legally capable of burning an alternate fuel. The Company reserves the right, in its sole discretion, to waive the aforementioned affidavit upon good cause being shown by the customer. This service shall be limited in the Company's sole discretion to the operational systems and of the Company.

If incremental facilities, other than remote metering costs included in the customer charge, are required on the Company's system to serve the customer, the cost of such facilities shall be paid for by the customer. If the customer converts to this service from another customer service classification without satisfying payment of facilities costs in the Company's Service and Main Extension tariff, the costs unrecovered by the Company must be prepaid by the customer. The customer shall be required to have remote meter reading facilities.

The customer must agree to discontinue gas service for a minimum of thirty (30) consecutive days per year. On or before November 1 of each year, the Company shall notify each 280 Day transportation customer of the starting and ending dates for the thirty (30) consecutive days of non-service for that year for that customer. The Company, at its sole option, may discontinue service for up to fifty-five (55) additional days during the Winter Period from November through April inclusive upon twenty-four (24) hours notice. The Company will use its best efforts to provide the maximum notification of service disruption for the additional fifty-five (55) day period. The additional fifty-five (55) days of interruption need not be consecutive.

If a customer requests gas on an emergency basis when gas service would otherwise be precluded under this service classification, the Company may, in its sole discretion, tender gas if it determines that an emergency does exist and the Company has the ability to provide the gas service. Gas consumed under this provision will be priced at a rate per therm equal to the highest cost of gas, as determined by the Company, during the time such service is rendered, adjusted for the applicable taxes and assessments, plus the Industrial General firm sales delivery rate.

The customer shall pay for any unauthorized gas usage at the rate of five times the daily index.

## II. RATE SCHEDULES

## 280 DAY TRANSPORTATION SERVICE (Cont'd)

Balancing
The customer shall be responsible for balancing with the interstate pipeline its upstream (prior to the city gate) daily nominations with daily takes. The customer shall provide nominations to the Company as provided in the Delivery Terms & Conditions.

Measurement
Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification except as specified herein. The Company shall be afforded the opportunity by the customer to inspect the facilities to properly ascertain the gas-using capacity and alternate fuel capability on the customer's premises.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

### INTERRUPTIBLE TRANSPORTATION SERVICE - ITS (Cont'd)

Terms and Conditions
Customers taking service under this rate schedule will be subject to the terms and conditions of Delivery Service, Section 9 - Daily Metered Delivery Service, of the Company's Delivery Tariff.

A written interruptible service agreement (Service Agreement) on the Company's standard form for a minimum period, as defined in the Service Agreements, shall be required for Interruptible Transportation service. The Company will make service available under this tariff within sixty (60) days of receipt of the completed Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily or monthly consumption, provisions for notice of interruption and additional charges for excess usage, terms of payment and other terms and conditions of service.

Customer shall pay its bills monthly. Any amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed, are subject to a late payment charge of one and one half percent (1½%) per month on the unpaid balance.

It is the customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times.

The customer must certify in a signed affidavit, appended to the contract, that the installation being served is physically and legally capable of burning an alternate fuel. The Company reserves the right, in its sole discretion, to waive the aforementioned affidavit upon good cause being shown by the customer. This service shall be limited in the Company's sole discretion to the operational systems of the Company.

If incremental facilities, other than remote metering costs included in the customer charge, are required on the Company's system to serve the customer, the cost of such facilities shall be paid for by the customer. If the customer converts to this service from another customer service classification without satisfying payment of facilities costs in the Company's Service and Main Extension tariff, the costs unrecovered by the Company must be prepaid by the customer. The customer shall be required to have remote meter reading facilities.

If a customer requests gas on an emergency basis when gas service would otherwise be precluded under this service classification, the Company may, in its sole discretion, tender gas if it determines that an emergency does exist and the Company has the ability to provide the gas service. Gas consumed under this provision will be priced at a rate per therm equal to the highest cost of gas, as determined by the Company during the time such service is rendered, adjusted for the applicable taxes and assessments, plus the Industrial General firm sales delivery rate.

The customer shall pay for any unauthorized gas usage at the rate of five times the daily index.

Balancing
The customer shall be responsible for balancing with the interstate pipeline its upstream (prior to the city gate) daily nominations with daily takes. The customer shall provide nominations to the Company as provided Delivery Terms and Conditions.

Measurement
Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification except as specified herein. The Company shall be afforded the opportunity by the customer to inspect the facilities to properly ascertain the gas-using capacity and alternate fuel capability on the customer's premises.
Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

9 DAILY METERED DELIVERY SERVICE

9.1 Applicability

Section 9 of this tariff shall be applicable in the following conditions:

9.1.1 All Customers whose service may be interrupted at any time during the year shall be required to take daily metered Delivery Service.

9.1.2 Any Customer, regardless of annual Gas Usage, may elect daily metered Delivery Service.

9.1.3 ***Customers under Rate Schedules G-43, G-53, and G-54 wishing to take Delivery Service are required to take Daily Metered Delivery Service. In addition,*** the Company may require a Customer to take daily metered Delivery Service if the Company determines that the daily Gas Usage characteristics of the Customer cannot be accurately modeled using the Company's Consumption Algorithm or if the volumes reasonably anticipated by the Company to be used by the Customer are of a size that may materially affect the integrity of the Company's distribution system.

9.2 Delivery Service Provided

This service provides delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day. For Customers taking Delivery Service under Rate Schedules ***G-43, G-53, and G-54*** this service provides firm, year-round delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point.

9.3 Nominations and Scheduling of Service

9.3.1 The Supplier is responsible for nominating and delivering to the Designated Receipt Point(s) every Gas Day an amount of Gas that equals the aggregated Gas Usage of Customers in the Aggregation Pool plus the Company Gas Allowance in accordance with Section 8 of this tariff.

9.3.2 Nominations shall be communicated to the Company by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means.

9.3.3 Nominations for the first Gas Day of a Month shall be submitted to the Company no later a separate pool from Customers subscribing to daily metered service under Rate Schedules G-43, G-53, and G-54.

20.6.2 Non-daily metered Customers taking Delivery Service pursuant to Section 10 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Gas Service Areas.

20.6.3 Daily metered Customers taking Delivery Service pursuant to Section 9 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Gas Service Areas.

20.6.4 A separate Supplier account will be established for each Supplier Aggregation Pool.

20.6.5 The election of any service from the Company by the Supplier shall apply to the entire Aggregation Pool and not just an individual customer in the Aggregation Pool.

20.6.6 The Company may charge a monthly fee to the Supplier for each Aggregation Pool pursuant to Attachment D.

20.7 Imbalance Trading

20.7.1 Prior to the imposition of imbalance charges, the Supplier may engage in trading daily and monthly imbalances for the previous Month, provided that daily imbalance trades are communicated to the Company within three (3) Business Days upon the Company's provision of information on Supplier imbalances for said Month.

20.7.2 The Company will make available a list of Suppliers by Gas Service Area making deliveries during the previous Month.m

20.7.3 Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company.

20.7.4 Daily imbalance trades must be point-specific on those Gas Days when the Transporting Pipeline required the Company to balance on a point-specific basis.

20.8 Billing and Payment

20.8.1 By the tenth (10th) Business Day of the calendar month, the Company shall render to the Supplier a statement of the quantities delivered and amounts owed by the Supplier for the

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II RATE SCHEDULES



ORIGINAL
N.H.P.U.C. Case No. DG 08-009
Exhibit No. # 19
Witness

Issued: February 25, 2008
Effective: August 24, 2008

Issued: By
Nickolas Stavropoulos
Title: President

# I. GENERAL TERMS AND CONDITIONS

## 1 - SERVICE AREA

1(A) Service Area. The area authorized to be served by the Company and to which this tariff applies are the following cities and towns: Allenstown, Amherst, Auburn, Bedford, Belmont, Berlin, Boscawen, Bow, Concord, Derry, Franklin, Gilford, Goffstown, Hollis, Hooksett, Hudson, Laconia, Litchfield, Londonderry, Loudon, Manchester, Merrimack, Milford, Nashua, Northfield, Pembroke, Sanbornton, Tilton and part of Canterbury and Winnesquam. (T)

## 2 - GENERAL TERMS AND CONDITIONS

2(A) Filing. A copy of this tariff is on file with the New Hampshire Public Utilities Commission and is open to inspection at the offices of the Company.

2(B) Revisions. This tariff may be revised, amended, supplemented, or otherwise changed from time to time in accordance with the rules of the New Hampshire Public Utilities Commission and such changes, when effective, shall have the same force as the original tariff.

2(C) Application. The tariff provisions apply to everyone lawfully receiving gas supply service and/or delivery-only service from the Company under the rates herein and receipt of gas service shall constitute the receiver a customer of the Company as the term is used herein whether service is based upon contract, agreement, accepted signed application, or otherwise.

2(D) Statement by Agents. No representative has the authority to modify a tariff rule or provision or to bind the Company by a promise or representation contrary thereto.

2(E) No Prejudice of Rights. The failure of the Company to enforce any of the terms of this tariff shall not be deemed a waiver of its right to do so.

2(F) Gratuities to Employees. The Company's employees are strictly forbidden to demand or accept any personal compensation or gifts for service rendered by them while working for the Company on the Company's time.

2(G) Advance Payments. Payments to the Company for charges provided in these rules and regulations to be borne by the customer shall be made in advance.

2(H) Assignment. Subject to the rules and regulations, all contracts by the Company shall be binding upon, and oblige, and continue for the benefit of, the successors and assigns, heirs, executors, and administrators of the parties hereto.

# I. GENERAL TERMS AND CONDITIONS

## 7 - SERVICE AND MAIN EXTENSIONS

7(A) ~~Service and Main Extensions. In areas where the Company is authorized to operate, subject to the Application for Service provisions of this tariff, service is available as follows:~~ Upon receipt of an application from a prospective Customer setting forth the location of the premises to be served, the extent of the service to be required and any other pertinent information requested by the Company, the Company will advise the Customer of the type and character of the service it will furnish, under the applicable tariff, and if required, the location of the Company's metering and related equipment. The Company will have sole reasonable discretion on the location of meters and other related equipment. Upon request, the Company will furnish detailed information describing the connections necessary between the Company's facilities and the Customer's premises and Customer and Company responsibilities for installation of facilities. (C)

7(B) An application for service will not be approved until the Customer has delivered to the Company a fully completed request for service form and the Company has determined that an adequate flow of Gas can be delivered to the Customer's Delivery Point under normal operating conditions.~~Residential. The following applies to service pipeline ("service") and main pipeline ("main") extensions in the case of residences [as hereinafter defined in Clause (J)].~~ (C)

~~20No contribution in Aid of Construction Required. Residential service is available without a contribution ("contribution in aid of construction") by the applicant ("customer") when the meter(s) is (are) located within 80 feet of the property line (as measured along the service) and within 5 feet of the closest corner of the residence to the street, there are no abnormal costs and either of the following conditions is satisfied~~

~~a)no main extension is involved; or~~

~~b)the 25 percent test [as hereinafter described in Clause (J)] is met. The cost of the service is not included in the 25 percent test in the case of residences~~

~~2) Contribution in Aid of Construction Required. A contribution in aid of construction is required when the conditions in paragraph (B) (1) are not satisfied. Except as provided in the following clause (I), the contribution is required before installation of the service, and/or main extension ("installation").~~

7(C) Whenever the estimated expenditures necessary to supply Gas to a Customer or to resume service to a Customer after a discontinuance of service for over twelve (12) months, for reasons other than the needs of the Company, shall be of such an amount that the income to be derived from gas service at the applicable rates will, in the opinion of the Company, be insufficient to warrant such expenditures, the Company may, in addition to the payments for Gas under the applicable rates, require the Customer to pay the whole or a part of such expenditures, or make such other reasonable payments as the Company may deem necessary.~~Other Than Residential. The following applies to service and main extensions in the case of buildings other than residences [as hereinafter defined in Clause (J)]~~ (C)

~~1)No Contribution in Aid of Construction Required. Service other than for a residence is available without a contribution in aid of construction when the 25 percent test is met and there are no abnormal costs. The cost of the service is included in the 25 percent test for buildings other than residences~~

~~Contribution in Aid of Construction Required. A contribution in aid of construction is required when the 25 percent test is not met or when there are abnormal costs. Except as provided hereinafter, the contribution is required to be made prior to installation.~~

7(D) The Company reserves the right to reject any application for service if the amount or nature of the service (C) applied for, or the distance of the premises to be served from existing, suitable gas distribution facilities, or the difficulty of access thereto is such that the estimated income from the service applied for is insufficient to yield a reasonable return to the Company, unless such application is accompanied by a cash payment or an undertaking satisfactory to the Company guaranteeing a stipulated revenue for a definite period of time, or both.~~Failure to Use Gas Facilities. If a customer fails, within nine months after the date a service requested by him is installed, either in whole or in part, to make use of the service, the customer will reimburse the Company for all costs of constructing, removing and retiring the service less any contribution in aid of construction made by him for the service, which will be forfeited.~~

~~7(E)~~ ~~Easements, Etc. The Company is not required to construct extensions other than in public ways unless the customer provides, in advance and without expense or cost to the Company, all necessary permits, consents, authorizations and right-of-way easements, satisfactory to the Company, for the construction, maintenance and operation of the pipeline.~~ (D)

~~2)7(F) Shortest Distance. Services are run the shortest practical safe distance to the meter location. However, a customer may have the Company install a longer alternate service provided that the customer defrays in advance of installation the extra expense.~~ (D)

## ~~I. GENERAL TERMS AND CONDITIONS~~

### ~~7 - SERVICE AND MAIN EXTENSIONS (Cont'd)~~

~~7(G) Extra Footage. The charge (contribution in aid of construction) for extra footage is the historical average cost per foot for the most recent twelve month period for which such cost has been computed by the Company; the cost will be updated annually; and the most recent annual computation will be used in calculating extra footage charges.~~ (D)

~~7(H) Winter Construction. Ordinarily, no new service pipes or main extensions are installed during the winter conditions (when frost is in the ground) unless the customer defrays the extra expenses.~~ (D)

~~7(I) Time For, and Refund Of, Contribution. Except as otherwise agreed by the Company under unusual circumstances, any required contributions in aid of construction will be made prior to installation by the Company of a service. To help cover the Company's expenses, damages and lost business, ten percent (10%) of the contribution will be forfeited to the Company and not be subject to being returned, where substantial construction of the building or buildings for which gas service has been sought is not commenced by the earlier of (1) November 30th next following submission of the application; and (2) the date when the Company commences construction of the main and service concerned prior to withdrawal of the application. Except as provided in the last preceding sentence and in Clause (D) above, the entire contribution will be refunded if and when the application is withdrawn. A new application may be submitted at any time.~~ (D)

~~7(J) Definitions. The following are definitions of terms used in these provisions relative to main and service extensions and are applicable only in such provisions~~ (D)

~~1)Residence; Residential. A "residence" is any free standing building in which each dwelling unit is separately metered, or a duplex residential building (whether or not it is individually metered); and "residential" means pertaining to a "residence", as so defined.~~

~~2)~~1) ~~Building Other Than a Residence; Other Than Residential. A "building other than a residence" is any building other than a "residence", as defined above; and "other than residential" means pertaining to a "building other than a residence", as so defined.~~

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Nickolas Stavropoulos
Title: President

## ~~I. GENERAL TERMS AND CONDITIONS~~

### ~~7 - SERVICE AND MAIN EXTENSIONS (Cont'd)~~

~~3) 25 Percent Test. The 25 percent test is calculated as follows:~~ (D)

~~The estimated annual margin must be equal to or greater than 25 percent of the estimated construction costs for the main and service extension, subject to the provision of the next two sentences. The cost of the service is included in the construction costs in the case of an extension for a building other than a residence, but not in the case of an extension for a residence. Abnormal costs are charged separately and are not included in the cost of the extension for the purpose of calculating the 25 percent test.~~

~~Subject to the provision of the last preceding paragraph, the customer(s) requesting the extension will be required to pay to the Company, in advance, any amount by which the estimated construction cost of the main and service extension exceeds four times the estimated annual margin. The contribution will be required to be made by the customers requesting the extension proportionally according to their respective estimated annual gas use.~~

~~Upon completion of the work and the expiration of twelve (12) months thereafter, the Company will recalculate the required contribution based upon the actual construction costs incurred and the actual annual margin. In the event that the recalculation results in a required contribution that is less than that originally made by the customer(s), the excess will be refunded to the customer(s) who originally made the contribution. In the event that the recalculation results in a required contribution that is more than that originally made by the customer(s), the difference shall be promptly contributed to the Company by the customer(s) who requested the extension.~~

~~If, during the period five (5) years immediately following the date of completion of construction of a particular main and/or service extension for which a contribution was required and made because of the 25 percent test, additional customers are connected to the extension, the contribution requirements will be recalculated, taking into account the estimated annual margin from the new customers; and the new customers will be required to pay the Company their proportional share of the contribution. The Company will make pro rata refunds to the customers who made the original payments, to the extent of the total amount of such shares of such new customers less any forfeitures. If the inclusion of such new customers would increase the estimated annual margin to such an extent that the 25 percent test is met, all unforfeited contribution payments will be returned to the customers who made them if and when the actual annual margin satisfies the 25 percent test~~ (D)

~~4) Estimated Annual Margin. The estimated annual margin is equal to the estimated revenue to be derived from the monthly Customer Charge and delivery charge to be received from the customer for gas service utilizing the particular main and/or service extension concerned during the first twelve (12) months after completion of the extension. The estimated annual margin does not include revenue received by the Company for the cost of gas. The Company shall recalculate the estimated annual margin for a twelve (12) month period at least once within a year of completion of the installation.~~ (D)

5) ~~Cost of Construction. The cost of construction of mains and/or services for both residences and buildings other than residences includes not only the cost of labor and materials for such construction, but also miscellaneous costs incidental thereto or associated therewith.~~

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## ~~I. GENERAL TERMS AND CONDITIONS~~

### ~~7 - SERVICE AND MAIN EXTENSIONS (Cont'd)~~

~~5) Abnormal Costs. Abnormal costs are service and/or main construction costs that are attributable to frost, ledge, ditching, backfill and/or other conditions not uniformly encountered in service and/or main construction and that are peculiar to the particular service and/or main construction concerned. Abnormal costs are to be paid by the customer.~~ (D)

~~6) Main and Service Extensions. This term refers to the service and, if a main is required to be extended, the main extension, required to be constructed to provide requested gas service.~~ (D)

~~7(K) Reasonable Duration and Non-Discrimination. Under none of the foregoing provisions will the Company be required to install service pipes or to contract main extensions where the business to be secured may not be of reasonable duration or will tend, in any way, to constitute unreasonable discrimination.~~ (D)

~~7(L) Title. Title of all extensions constructed in accordance with the above shall be vested in the Company.~~ (D)

~~7(M) Other Requirements. The Company generally will not approve any application or, if it shall have given such approval, will not proceed or continue with main and/or service construction unless the Company is satisfied~~ (D)

~~(1)That the final site plans, sub-division plans and plans and specification for building or buildings to be served by the main and/or service concerned, including plans for waste disposal, water and other associated systems and facilities, have been prepared and approved by owner;~~

~~(2)That all permits, exceptions, approvals and authorizations of governmental bodies or agencies required for construction of such building or buildings and associated systems and facilities have been obtained;~~

~~(3)That the customer is proceeding or plans promptly to proceed with such construction; and~~

~~(4)That nothing has occurred or failed to occur which will or is likely to prevent or interfere with such construction.~~

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Issued: By________________________
Nickolas Stavropoulos
Title: President

# I. GENERAL TERMS AND CONDITIONS

## 16 - COST OF GAS CLAUSE

(16) **Summer Season** – The calendar months May 1 through October 31.
(17) **Off-System Sales Margin** - The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.
(18) **Winter Commodity** - The gas supplies procured by the Company to serve firm load in the Winter Season.
(19) **Winter Demand** - Gas supply demand, peaking demands, storage and transmission capacity procured by the Company to service firm load in the Winter Season.
(20) **Winter Season** – The calendar months November 1 through April 30.
(21) **PR Allocator** – The percentage of annual capacity charges assigned to the Winter Season calculated using the Proportional Responsibility Method.
(22) **Purchased Gas Working Capital** - The allowable working capital derived from Winter Season and Summer Season demand and commodity related costs.

### 16(F) Approved Cost

The Cost of Gas calculation utilizes information periodically established by the NHPUC. The table below lists the approved costs factors:

| Variable | Description | Approved Figure | |
|---|---|---|---|
| MISC | Miscellaneous Overhead | ~~$135,339~~ $56,975 | (R) |
| PS | Production and Storage Capacity | ~~$2,105,212~~ $1,869,226 | (R) |
| WCA% | Working Capital Allowance Percentage | ~~0.967%~~ 0.522% | (R) |
| BD% | Bad Debt Percentage | ~~2.57%~~ 2.509% | (R) |

### 16(G) Cost of Gas (COG) Calculations by Customer Class

The Cost of Gas (COG) Formula shall be computed on a semiannual basis for three (3) groups of customer classes as shown on the following table. The computation will use forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts shall be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

The COG for the Residential rate classes shall represent the total system average unit cost of gas of meeting firm sales load, projected in each COG filing. The Commercial & Industrial (C&I) Low Winter (LW) and High Winter (HW) rates will be calculated in the following way: first, the demand unit cost of gas, the sum of purchased and stored gas demand costs divided by projected prorated sales, will be multiplied by the applicable load factor ratio and then multiplied by the correction factor. This adjusted demand factor will then be added to the commodity factor, adjustment factor and indirect cost of gas rate to determine the total COG rates for the C&I LW and HW rate classes. The two load factor ratios shall be derived once a year, for effect every November 1 through October 31, using the ratio of the unit capacity cost of each C&I group to the total system unit capacity cost that is determined in the Company's submittal of its Capacity Allocators, for Capacity Assignment purposes, filed with its Winter COG, and as presented in Attachment F of the Delivery Service Terms and Conditions. The Correction Factor aligns the peak day volumes used to calculate the load factor ratios with the seasonal throughput volumes applied to the COG calculations.

| GROUP | CUSTOMER CLASSES | |
|---|---|---|
| Residential | Residential Heating and Non-Heating | |
| Commercial and Industrial: Low Winter Use | **G-51, G-52 G-53, and G-54, ~~and G-63~~** | (D) |
| Commercial and Industrial: High Winter Use | **G-41, G-42 and G-43** | |

# I. GENERAL TERMS AND CONDITIONS

## 18. LOCAL DELIVERY ADJUSTMENT CLAUSE

**Section**



### 18(A) Purpose

The purpose of the Local Delivery Adjustment Clause ("LDAC" or this "Clause") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges ("CC"), Winter Period Surcharges ("WPS"), Environmental Surcharges ("ES") including the Relief Holder Surcharge ("RHS") and the Manufactured Gas Program Surcharge ("MGP"), to return interruptible transportation margin credits ("ITMC"), recover gas restructuring expenses ("GRE"), rate case expenses ("RCE"), Residential Low Income Assistance Program costs ("RLIAP") and any other expenses the NHPUC may approve from time to time.

### 18(B) Applicability

This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers as shown on the table below. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 18-(L) "Other Rules."

| *Applicability* | *CC 18(C)* | *ES 18(D)* | *ITMC 18(E)* | *GRE 18(F)* | *RCE 18(G)* | *RLIAP 18(H)* | *PRAF 18(I)* | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | (N) |
| Residential Non-Space Heating – R-1, | 1 | X | X | N/A | 1 | X | X | |
| Residential Space Heating – R-3, R-4 | 1 | X | X | N/A | 1 | X | X | |
| Small C&I – G-41, G-51 | 1 | X | X | X | 1 | X | X | |
| Medium C&I – G-42, G-52 | 1 | X | X | X | 1 | X | X | |
| Large C&I – G-43, G-53, G-54 ~~G-63~~ | 1 | X | X | X | 1 | X | X | (D) |

Notes:
N/A Not applicable
X Applicable to all
1 As ordered by the NHPUC

Issued: February 25, 2008
Effective: August 24, 2008

Issued: By__________________________
Nickolas Stavropoulos
Title: President

# I. GENERAL TERMS AND CONDITIONS

## 18. LOCAL DELIVERY ADJUSTMENT CLAUSE

**18(H)(6) Reconciliation Adjustments**

Prior to the Company's peak season Cost of Gas filing, the Company will calculate the difference between (a) the revenue derived by multiplying the actual firm sales and delivery service throughput by the RLIAP Rate through October 31st, and (b) the actual costs of the program which consists of (1) the revenue shortfall calculated by applying the actual billing determinants of the RLIAP classes to the difference in the regular and reduced residential base rates in effect for the annual reconciliation period and (2) the start-up, administrative and marketing costs associated with the implementation of the program, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates. The combined costs will then be recorded in the deferred RLIAP account 175.39. The Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

**18(I) Pension Costs and Post-Retirement Benefits Other Than Pensions Allowable for the LDAC** (N)

**18(I)(1) Purpose**

The Purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to reconcile pension and post-retirement benefits other than pensions ("PBOP") expense amounts included in the Company's distribution rates with the total expense amounts booked by the Company pursuant to FAS 87 and FAS 106 and as amended by FAS 158.

**18(I)(2) Applicability**

The Pension and Post Retirement Benefits Other than Pensions Reconciliation Adjustment Factor ("PRAF") shall be applied to all firm sales and transportation tariff customers. The PRAF shall be filed with the Company's peak season Cost of Gas Clause filing and shall be calculated annually by the Company and be subject to review and approval by the Commission.

**18(I)(3) Effective Date**

On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the PRAF applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

**18(I)(4) Pension and PBOP Costs Allowable for LDAC**

The costs to be recovered shall be comprised of all the pension costs associated with the Company's Pension Plans as determined by SFAS-87 and all of the PBOP costs as determined by SFAS-106 (and as amended by FAS 158) and as approved by the NHPUC that have not yet been included in the Company's distribution rates plus associated carrying charges.

# I. GENERAL TERMS AND CONDITIONS

## 18. LOCAL DELIVERY ADJUSTMENT CLAUSE

### 18(I)(5) PRAF Formula

$$PRAF_x = \frac{RA_x + cc(URD_x - DTA_x) + PPRA_x}{A{:}TPvol}$$ (N)

**Where:**

PRAF = The annual Pension/PBOP Reconciliation Adjustment Factor.

$RA_x$ = The Reconciliation Adjustment for $Year_x$ is one-third of the Unamortized Reconciliation Deferral at the end of the Prior Year.

cc = The Cost of Capital is the tax-effected weighted-average cost of capital as allowed by the NHPUC in the Company's most recent rate case.

$URD_x$ = The Unamortized Reconciliation Deferral is the amount of the Reconciliation Deferral not yet included in distribution rates. At the beginning of $Year_x$ the Unamortized Reconciliation Deferral is the sum of: (1) the Unamortized Reconciliation Deferral at the beginning of the Prior Year; plus (2) the Reconciliation Deferral for the Prior Year; minus (3) the Reconciliation Adjustment for the Prior Year.

$DTA_x$ = The Deferred Tax Amount is the deferred taxes associated with the Pre-Paid Amount and the URD at the end of the Prior Year.

$PPRA_x$ = The Past Period Reconciliation Amount is (a) the difference between: (1) the amount of PRAF revenue that should have been collected in the Prior Year; and (2) the amount of PRAF revenue actually received by the Company in the Prior Year and (b) the amount computed in the clause (a) times the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

A:TPvol = Annual forecasted throughput volumes inclusive of all sales and transportation throughput.

x = The current year.

### 18(~~I~~)(J) Effective Date of Local Delivery Adjustment Clause (X)

The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

### 18(~~J~~K) Local Delivery Adjustment Clause Formulas (X)

The LDAC shall be calculated on an annual basis, by customer, by summing up the various factors included in the LDAC, where applicable.

# I. GENERAL TERMS AND CONDITIONS

## 18. LOCAL DELIVERY ADJUSTMENT CLAUSE

**LDAC Formula**

$LDAC^X = CC^X + ES - ITMC + GREF^x + RCE^x + RLIAP + PRAF$ (N)

**And:**

$ES^X = RHS + MGP$

**Where:**

| | |
|---|---|
| $LDAC^X$ | Annualized class specific Local Delivery Adjustment Charge. |
| $CC^X$ | Annualized class specific CC or EE Charge. |
| ITMC | Annualized Interruptible Transportation Margin Credit. |
| ES | Total firm annualized ES. |
| RHS | Annualized charge to recover the costs of the closure of the Relief Holder at Gas Street, Concord, NH |
| MGP | Annualized charge to cover the remediation costs related to former manufactured gas plants. |
| $GREF^x$ | Total firm annualized class specific Gas Restructuring Expense Factor. |
| $RCE^x$ | Class specific Rate Case Expense Factor. |
| RLIAP | Residential Low Income Assistance Program Rate |
| PRAF | Pension costs and Post Retirement Benefits Other Than Pensions Adjustment Factor (N) |

**18(~~K~~L) Application of LDAC to Bills** (X)

The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 18(B).

**18(~~L~~M) Other Rules** (X)

(1) The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.
(2) Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.
(3) The Company may implement an amended LDAC with the NHPUC approval at any time.
(4) The NHPUC may, at any time, require the Company to file an amended LDAC.
(5) The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.

**18(~~M~~N) Amendments To Uniform System Of Accounts** (X)

**175.42 Interruptible Transportation Margin Reconciliation Adjustment for LDAC**

This account shall be used to record the cumulative difference between annual Interruptible Transportation margin returns and annual Interruptible Transportation margins. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Clause, 18(E).

# I. GENERAL TERMS AND CONDITIONS

## 18. LOCAL DELIVERY ADJUSTMENT CLAUSE

**175.85 Gas Restructuring Expense Reconciliation Adjustment**
`

This account shall be used to record the cumulative difference between the recovery and actual amounts of third party incremental expenses associated with the Company's Gas Restructuring initiatives. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Clause, 18(F).

**175.22 Demand-Side Management and/or Energy Efficiency Reconciliation Adjustment**

This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Clause, 18(C).

**175.90 Environmental Response Costs Reconciliation Adjustment**

This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Clause, 18(D).

**175.65 Rate Case Expense Reconciliation Adjustment**

This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(G).

**175.39 Residential Low Income Assistance Program Reconciliation Adjustment**

This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the RLIAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 18(H).

**175.__ Pension and PBOP Expense Reconciliation Adjustment** (N)

This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the PRAF rate and the total pension and PBOP expense amounts booked by the Company in the prior year.

# I. GENERAL TERMS AND CONDITIONS

## 19 - SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY (Cont'd)

### PRIORITIES

Firm rate customers shall be serviced according to the following preference categories with the first and each succeeding category having preference over the succeeding categories

1) Company use for fuel and lost and unaccounted for

2) Firm sales or transportation service for high priority residential uses including apartment buildings and other multi-unit buildings, small commercial establishments using less than 50 DT on a peak day, schools, hospitals, police protection, fire protection, sanitation facilities and correctional facilities

3) Firm sales or transportation service for essential agricultural uses, as defined by the Secretary of Agriculture, for full food and natural fiber production, process and feedstock use for fertilizer and agricultural chemicals, process and feedstock for animal feeds and food, food quality maintenance, food packaging, marketing and distribution for food related products and on farm uses

4) Firm sales or transportation service for large commercial requirements (50 DT or more on a peak day), firm industrial requirements for plant protection, feedstock and process needs and firm industrial sales up to 300 DT per day

5) Firm sales or transportation service for all industrial requirements not specified in (2), (3), (4), (5), (6) (7), (10) or (11), including the firm period of 280 Day sales or transportation

6) Firm sales or transportation service including the firm period of 280 Day sales or transportation or transportation for industrial requirements for boiler fuel use at less than 1,500 DT per day, but more than 300 DT per day, where alternate fuel capabilities can meet such requirements

7) Firm sales or transportation service including the firm period of 280 Day sales or transportation or transportation for industrial requirements for large volume (1,500 DT or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements

8) Interruptible sales or transportation service and the non-firm period of 280 Day sales or transportation.

### STORAGE INJECTION

Within each category, storage injection required to meet the needs of higher priorities may be given preference over all other uses within that category.

### PENALTY

For all unauthorized volumes of gas taken by a customer, the customer shall pay the Company a penalty of ~~$1.50 per therm~~ five times the daily index for each therm taken. Such penalty shall be added to the regular rates in effect. The Company shall have the right, without obligation, to waive any penalty for unauthorized use of gas, if on the day when the penalty was incurred deliveries to other of the Company's customers were not adversely affected. Continued unauthorized use, at the sole discretion of the Company, may result in termination of service. (I)

## II. RATE SCHEDULES

### Residential Non Heating Rate
### Classification No. R-1

Availability
This rate is available to all residential customers who do not have gas space heating equipment. Available for use which is separately metered and billed for each dwelling unit. Availability is limited to use in locations served by the Company's mains and for which the Company's facilities are adequate.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | | |
|---|---|---|---|---|---|
| Customer Charge Per Meter | ~~$0.2303~~ $0.4583 per day | or | ~~$6.91~~ $13.75 | per 30 day month | (I) |
| Winter Period | | | | | |
| First 10* therms per 30 day month at | | | ~~$0.2678~~ $0.0228 | per therm | (R) |
| All over 10 therms per 30 day month at | | | ~~$0.2364~~ $0.0201 | per therm | (R) |
| Summer Period | | | | | |
| First 10* therms per 30 day month at | | | ~~$0.2678~~$ $0.0228 | per therm | (R) |
| All over 10 therms per 30 day month at | | | ~~$0.2364~~ $0.0201 | per therm | (R) |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated billwill be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $~~5.00~~15.00 charge for each bad check tendered for payment. (I)

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

### Residential Heating Rate
### Classification No. R-3

Availability
This rate is for all residential use for those domestic customers who use gas as the principal household heating fuel. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company's facilities are adequate.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | | |
|---|---|---|---|---|---|
| Customer Charge Per Meter | ~~$0.3293~~ $0.6583 per day | or ~~$9.88~~ $19.75 | per 30 day month | (I) |
| Winter Period | | | | |
| First 100 * therms per 30 day month at | | ~~$.2945~~ $0.2291 | per therm | (R) |
| All over 100 therms per 30 day month at | | ~~$0.1711~~ $0.1331 | per therm | (R) |
| Summer Period | | | | |
| First 20 * therms per 30 day month at | | ~~$.2945~~ $0.2291 | per therm | (R) |
| All over 20 therms per 30 day month at | | ~~$0.1711~~ $0.1331 | per therm | (R) |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $~~5.00~~15.00 charge for each bad check tendered for payment. (I)

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

## Low Income Residential Heating Rate
## Classification No. R-4

Availability

This rate is for residential use for those domestic customers who use gas as the principal household heating fuel if any member of the household qualifies for a benefit through one of the programs listed below, subject to the qualification period described under the “Terms and Conditions” of this rate. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company’s mains and for which the Company facilities are adequate.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | ~~$0.1317~~ $0.2633 per day | or ~~$3.95~~ $7.90 | per 30 day month | (I) |
| Winter Period | | | | |
| First 100 * therms per 30 day month at | | ~~$.1178~~ $0.0916 | per therm | (R) |
| All over 100 therms per 30 day month at | | ~~$0.0684~~ $0.0532 | per therm | (R) |
| Summer Period | | | | |
| First 20 * therms per 30 day month at | | ~~$.1178~~ $0.0916 | per therm | (R) |
| All over 20 therms per 30 day month at | | ~~$0.0684~~ $0.0532 | per therm | (R) |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company’s Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

## II. RATE SCHEDULES

### Low Income Residential Heating Rate
### Classification No. R-4
### (Continued)

Terms and Conditions
For those customers qualifying for the program this rate R-4 shall apply for a one year period. On the date that the one-year period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-4 expires, the rate on each account shall revert back to the non-low income Residential Heating Rate, R-3. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following October 31, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $~~5.00~~ 15.00 charge for each bad check tendered for payment. (I)

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

# Commercial/Industrial Service
# Low Annual Use, High Winter Use
# Rate Classification G-41

Availability
This rate is available for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | ~~$0.8213~~ $1.6667 per day | or ~~$24.64~~ $50.00 | per 30 day month | (I) |
| Winter Period | | | | |
| First 100 * therms per 30 day month at | | ~~$0.3275~~ $0.2268 | Per therm | (R) |
| All over 100 therms per 30 day month at | | ~~$0.2130~~ $0.1475 | Per therm | (R) |
| Summer Period | | | | |
| First 20 * therms per 30 day month at | | ~~$0.3275~~ $0.2268 | Per therm | (R) |
| All over 20 therms per 30 day month at | | ~~$0.2130~~ $0.1475 | Per therm | (R) |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

## II. RATE SCHEDULES

## Commercial/Industrial Service
## Low Annual Use, High Winter Use
## Rate Classification G-41
## (Continued)

Terms and Conditions
U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $~~5.00~~15.00 charge for each bad check tendered for payment. (I)

A customer must give at least four (4)days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

# Commercial/Industrial Service
# Medium Annual Use, High Winter Use
# Rate Classification G-42

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or eqaul to 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | ~~$2.3120~~ $4.6667 per day | or ~~$69.36~~ $140.00 | per 30 day month | (I) |
| Winter Period | | | | |
| First 1000 * therms per 30 day month at | | ~~$0.2716~~ $0.2476 | per therm | (R) |
| All over 1000 therms per 30 day month at | | ~~$0.1794~~ $0.1636 | per therm | (R) |
| Summer Period | | | | |
| First 400 * therms per 30 day month at | | ~~$0.2716~~ $0.2476 | per therm | (R) |
| All over 400 therms per 30 day month at | | ~~$0.1794~~ $0.1636 | per therm | (R) |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

## II. RATE SCHEDULES

## Commercial/Industrial Service
## Medium Annual Use, High Winter Use
## Rate Classification G-42
## (Continued)

Terms and Conditions

Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $~~5.00~~15.00 charge for each bad check tendered for payment. (I)

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

## Commercial/Industrial Service
## High Annual Use, High Winter Use
## Rate Classification G-43

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

| | | | | | |
|---|---|---|---|---|---|
| Customer Charge Per Meter | ~~$9.9797~~ $20.0000 per day | or | ~~$299.39~~ $600.00 | per 30 day month | (I) |
| Winter Period | | | | | |
| All therms per 30 day month at | | | ~~$0.1591~~ $0.1649 | per therm | (I) |
| Summer Period | | | | | |
| All therms per 30 day month at | | | ~~$0.0728~~ $0.0754 | per therm | (I) |

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

## II. RATE SCHEDULES

## Commercial/Industrial Service
## High Annual Use, High Winter Use
## Rate Classification G-43
## (Continued)

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $~~5.00~~15.00 charge for each bad check tendered for payment. (I)

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

Issued: February 25, 2008
Effective: August 24, 2008

Issued: By___________________________
Nickolas Stavropoulos
Title: President

## II. RATE SCHEDULES

# Commercial/Industrial Service
# Low Annual Use, Low Winter Use
# Rate Classification G-51

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | ~~$0.8270~~ $1.6667 per day | or ~~$24.81~~ $50.00 | per 30 day month | (I) |
| Winter Period | | | | |
| First 100 * therms per 30 day month at | | ~~$0.2525~~ $0.1103 | per therm | (R) |
| All over 100 therms per 30 day month at | | ~~$0.1631~~ $0.0712 | per therm | (R) |
| Summer Period | | | | |
| First 100 * therms per 30 day month at | | ~~$0.2525~~ $0.1103 | per therm | (R) |
| All over 100 therms per 30 day month at | | ~~$0.1631~~ $0.0712 | per therm | (R) |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

## II. RATE SCHEDULES

## Commercial/Industrial Service
## Low Annual Use, Low Winter Use
## Rate Classification G-51
## (Continued)

Terms and Conditions
Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $~~5.00~~ 15.00 charge for each bad check tendered for payment. (I)

A customer must give at least four (4)days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

## Commercial/Industrial Service
## Medium Annual Use, Low Winter Use
## Rate Classification G-52

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | ~~$2.3097~~ $4.6667 per day | or ~~$69.29~~ $140.00 | per 30 day month | (I) |
| Winter Period | | | | |
| First 1000 * therms per 30 day month at | | ~~$0.1734~~ $0.1295 | per therm | (R) |
| All over 1000 therms per 30 day month at | | ~~$0.1177~~ $0.0879 | per therm | (R_ |
| Summer Period | | | | |
| First 1000 * therms per 30 day month at | | ~~$0.1275~~ $0.0952 | per therm | (R) |
| All over 1000 therms per 30 day month at | | ~~$0.0734~~ $0.0548 | per therm | (R) |

* The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

## II. RATE SCHEDULES

## Commercial/Industrial Service
## Medium Annual Use, Low Winter Use
## Rate Classification G-52
## (Continued)

**Terms and Conditions**

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $~~5.00~~15.00 charge for each bad check tendered for payment. (I)

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

Issued: February 25, 2008
Effective: August 24, 2008

Issued: By__________________________
Nickolas Stavropoulos
Title: President

## II. RATE SCHEDULES

# Commercial/Industrial Service
# High Annual Use, Load Factor Less Than 90%
# Rate Classification G-53

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage less than 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | $20.00 per day | ~~$300.00~~ $600.00 | per month | (I) |
| Winter Period<br>All therms per month at | | ~~$0.1074~~ $0.1116 | per therm | (I) |
| Summer Period<br>All therms per month at | | ~~$0.0514~~ $0.0534 | per therm | (I) |

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

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## II. RATE SCHEDULES

## Commercial/Industrial Service
## High Annual Use, Load Factor Less Than 90%
## Rate Classification G-53
## (Continued)

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the (I) unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $~~5.00~~15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

## Commercial/Industrial Service
## High Annual Use, Load Factor ~~Less~~ Greater Than ~~110~~90% (T)
## Rate Classification G-54

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage ~~less~~ greater than or equal to ~~110~~90% of the average usage of December, January and February as determined by the Company's records and procedures. (T)

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

| | | | | |
|---|---|---|---|---|
| Customer Charge Per Meter | $20.00 per day | ~~$300.00~~ $600.00 | per month | (I) |
| Winter Period All therms per month at | | ~~$0.0799~~ $0.0374 | per therm | (R) |
| Summer Period All therms per month at | | ~~$0.0410~~ $0.0202 | per therm | (R) |

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

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## II. RATE SCHEDULES

## Commercial/Industrial Service
## High Annual Use, Load Factor ~~Less~~ Greater Than ~~110~~90%
## Rate Classification G-54
## (Continued)

(T)

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $~~5.00~~15.00 charge for each bad check tendered for payment. (I)

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

# ~~Commercial/Industrial Service~~
# ~~High Annual Use, Load Factor Greater Than 110%~~
# ~~Rate Classification G-63~~

(D)

~~Availability~~
~~This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage greater than or equal to 110% of the average usage of December, January and February as determined by the Company's records and procedures.~~

~~Character of Service~~
~~Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.~~

~~Delivery Charge~~

| | | |
|---|---|---|
| ~~Customer Charge Per Meter~~ | ~~$300.00~~ | ~~per month~~ |
| ~~Winter Period~~ | | |
| ~~All therms per month at~~ | ~~$0.0345~~ | ~~per therm~~ |
| ~~Summer Period~~ | | |
| ~~All therms per month at~~ | ~~$0.0188~~ | ~~per therm~~ |

~~The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.~~

~~Supplier Charges~~
~~If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.~~

~~Other Charges for Delivery Service~~
~~The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), as in effect from time to time and on file with he New Hampshire Public Utilities Commission (NHPUC). The delivery charge presented above are exclusive of these charges. Refer to Page 73 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.~~

~~Meter Account Charge~~
~~When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.~~

**PROVISIONS DELETED**
**RESERVED FOR FUTURE USE**

~~II. RATE SCHEDULES~~

~~Commercial/Industrial Service~~
~~High Annual Use, Load Factor Greater Than 110%~~
~~Rate Classification G-63~~
~~(Continued)~~

(D)

~~Terms and Conditions~~

~~To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.~~

~~The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.~~

~~Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.~~

~~Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance -- equivalent to an eighteen percent (18%) annual rate. There is a $5.00 charge for each bad check tendered for payment.~~

~~A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.~~

~~Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.~~

**PROVISIONS DELETED**
**RESERVED FOR FUTURE USE**

## II. RATE SCHEDULES

## OUTDOOR GAS LIGHTING

Availability
This rate is available for residential outdoor gas lighting where such service is provided from the Company's existing delivery system to a standard gas light fixture or fixtures, located on the customer's premises, and when it is not feasible to meter such service along with other gas used on the premises and bill the same under the rate in effect for all other services.

Rate Per Light Per Month $10.50

The above rates shall be adjusted to reflect the recovery of all applicable taxes.

Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a location, an account charge is incurred in addition to all other charges. The account charge is $20.00 when the visit to the location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Meters are read and bills are presented monthly.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a ~~$5.00~~$15.00 charge for each bad check tendered for payment. (I)

A customer must give at least four (4) days notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

## STANDBY SERVICE

Availability
This service is available to commercial and industrial sales customers with a minimum of 5 MMBtu per hour connected load who have alternative fuel burning capability and who require that the Company maintain facilities and supply availability to provide natural gas service upon twenty-four (24) hour notice to the Company, and who have had a load factor of less than 15% determined by dividing the customer's consumption during the prior twelve (12) months by connected load times twenty-four (24) hours x 365 days and multiplying the result by 100%.

Character of Service
Standby service is for customers with alternative fuel supply availability who require the Company to supply natural gas on short notice. The charge hereunder is for the purpose of defraying the fixed costs associated with maintaining readiness to serve, including, but not limited to, the capital cost and cost of maintaining services, regulators, as well as the cost of system capacity, supplier demand charges and other supply capability on a continuous basis.

Rate

| Customer Charge Per Month | Winter $ Per Therm | Summer $ Per Therm | Demand per MMBtu/hr. MMBtu/hr. Connected Load |
|---|---|---|---|
| $40.00 | $0.5912 | $0.4512 | $150.00 |

In any month during which consumption exceeds connected load times twenty-four (24) hours x five (5) days the charge for service will be made under the customer's otherwise applicable tariff. The applicable Standby charge shall be the minimum bill in those months when gas flows. Standby service may be taken in conjunction with seasonal service. The seasonal service gas will be separately metered and the seasonal service meter will be locked during the non-seasonal service months unless a standby contract has been signed. This rate is not subject to the cost of gas rate. This rate is not available in conjunction with 280 day service.

The above rates shall be adjusted to reflect the recovery of all applicable taxes.

The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Terms and Conditions
To be eligible for standby service, a customer must sign a contract for a minimum of the five (5) winter months of November through April. Bills will be presented at the first of each month. Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a ~~$5.00~~$15.00 charge for each bad check tendered for payment. (I)

Issued: February 25, 2008
Effective: August 24, 2008

Issued: By___________________________
Nickolas Stavropoulos
Title: President

**II RATE SCHEDULES**
**FIRM RATE SCHEDULES**

| | Winter Period | | | | Summer Period | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Delivery Charge | Cost of Gas Rate Page 84 | LDAC Page 91 | Total Rate | Delivery Charge | Cost of Gas Rate Page 84 | LDAC Page 91 | Total Rate | |
| **Residential Non Heating - R-1** | | | | | | | | | |
| Customer Charge per Month per Meter | $13.75 | | | $13.75 | $13.75 | | | $13.75 | (I) |
| | ~~$6.91~~ | | | ~~$6.91~~ | ~~$6.91~~ | | | ~~$6.91~~ | |
| Size of the first block | 10 therms | | | | 10 therms | | | | |
| Therms in the first block per month at | $0.0228 | $1.1337 | $0.0184 | $1.1749 | $0.0228 | $0.9556 | $0.0381 | $1.0165 | |
| | ~~$0.2678~~ | ~~$1.1478~~ | ~~$0.0187~~ | ~~$1.4343~~ | ~~$0.2678~~ | ~~$0.9057~~ | ~~$0.0388~~ | ~~$1.2123~~ | |
| All therms over the first block per month at | $0.0201 | $1.1337 | $0.0184 | $1.1722 | $0.0201 | $0.9556 | $0.0381 | $1.0138 | |
| | ~~$0.2364~~ | ~~$1.1478~~ | ~~$0.0187~~ | ~~$1.4029~~ | ~~$0.2364~~ | ~~$0.9057~~ | ~~$0.0388~~ | ~~$1.1809~~ | |
| **Residential Heating - R-3** | | | | | | | | | |
| Customer Charge per Month per Meter | $19.75 | | | $19.75 | $19.75 | | | $19.75 | (I) |
| | ~~$9.88~~ | | | ~~$9.88~~ | ~~$9.88~~ | | | ~~$9.88~~ | |
| Size of the first block | 100 therms | | | | 20 therms | | | | |
| Therms in the first block per month at | $0.2291 | $1.1337 | $0.0189 | $1.3817 | $0.2291 | $0.9556 | $0.0387 | $1.2234 | |
| | ~~$0.2945~~ | ~~$1.1478~~ | ~~$0.0192~~ | ~~$1.4615~~ | ~~$0.2945~~ | ~~$0.9057~~ | ~~$0.0394~~ | ~~$1.2396~~ | |
| All therms over the first block per month at | $0.1331 | $1.1337 | $0.0189 | $1.2857 | $0.1331 | $0.9556 | $0.0387 | $1.1274 | |
| | ~~$0.1711~~ | ~~$1.1478~~ | ~~$0.0192~~ | ~~$1.3381~~ | ~~$0.1711~~ | ~~$0.9057~~ | ~~$0.0394~~ | ~~$1.1162~~ | |
| **Residential Heating - R-4** | | | | | | | | | |
| Customer Charge per Month per Meter | $7.90 | | | $7.90 | $7.90 | | | $7.90 | (I) |
| | ~~$3.95~~ | | | ~~$3.95~~ | ~~$3.95~~ | | | ~~$3.95~~ | |
| Size of the first block | 100 therms | | | | 20 therms | | | | |
| Therms in the first block per month at | $0.0916 | $1.1337 | $0.0189 | $1.2442 | $0.0916 | $0.9556 | $0.0387 | $1.0859 | |
| | ~~$0.1178~~ | ~~$1.1478~~ | ~~$0.0192~~ | ~~$1.2848~~ | ~~$0.1178~~ | ~~$0.9057~~ | ~~$0.0394~~ | ~~$1.0629~~ | |
| All therms over the first block per month at | $0.0532 | $1.1337 | $0.0189 | $1.2058 | $0.0532 | $0.9556 | $0.0387 | $1.0475 | |
| | ~~$0.0684~~ | ~~$1.1478~~ | ~~$0.0192~~ | ~~$1.2354~~ | ~~$0.0684~~ | ~~$0.9057~~ | ~~$0.0394~~ | ~~$1.0135~~ | |
| **Commercial/Industrial - G-41** | | | | | | | | | |
| Customer Charge per Month per Meter | $50.00 | | | $50.00 | $50.00 | | | $50.00 | (I) |
| | ~~$24.64~~ | | | ~~$24.64~~ | ~~$24.64~~ | | | ~~$24.64~~ | |
| Size of the first block | 100 therms | | | | 20 therms | | | | |
| Therms in the first block per month at | $0.2268 | $1.1337 | $0.0099 | $1.3704 | $0.2268 | $0.9583 | $0.0336 | $1.2187 | |
| | ~~$0.3275~~ | ~~$1.1479~~ | ~~$0.0101~~ | ~~$1.4855~~ | ~~$0.3275~~ | ~~$0.9078~~ | ~~$0.0342~~ | ~~$1.2695~~ | |
| All therms over the first block per month at | $0.1475 | $1.1337 | $0.0099 | $1.2911 | $0.1475 | $0.9583 | $0.0336 | $1.1394 | |
| | ~~$0.2130~~ | ~~$1.1479~~ | ~~$0.0101~~ | ~~$1.3710~~ | ~~$0.2130~~ | ~~$0.9078~~ | ~~$0.0342~~ | ~~$1.1550~~ | |
| **Commercial/Industrial - G-42** | | | | | | | | | |
| Customer Charge per Month per Meter | $140.00 | | | $140.00 | $140.00 | | | $140.00 | (I) |
| | ~~$69.36~~ | | | ~~$69.36~~ | ~~$69.36~~ | | | ~~$69.36~~ | |
| Size of the first block | 1000 therms | | | | 400 therms | | | | |
| Therms in the first block per month at | $0.2476 | $1.1337 | $0.0099 | $1.3912 | $0.2476 | $0.9583 | $0.0336 | $1.2395 | |
| | ~~$0.2716~~ | ~~$1.1479~~ | ~~$0.0101~~ | ~~$1.4296~~ | ~~$0.2716~~ | ~~$0.9583~~ | ~~$0.0336~~ | ~~$1.2635~~ | |
| All therms over the first block per month at | $0.1636 | $1.1337 | $0.0099 | $1.3072 | $0.1636 | $0.9583 | $0.0336 | $1.1555 | |
| | ~~$0.1794~~ | ~~$1.1479~~ | ~~$0.0101~~ | ~~$1.3374~~ | ~~$0.1794~~ | ~~$0.9078~~ | ~~$0.0342~~ | ~~$1.1214~~ | |
| **Commercial/Industrial - G-43** | | | | | | | | | |
| Customer Charge per Month per Meter | $600.00 | | | $600.00 | $600.00 | | | $600.00 | (I) |
| | ~~$299.39~~ | | | ~~$299.39~~ | ~~$299.39~~ | | | ~~$299.39~~ | |
| All therms over the first block per month at | $0.1649 | $1.1337 | $0.0099 | $1.3085 | $0.0754 | $0.9583 | $0.0336 | $1.0673 | |
| | ~~$0.1591~~ | ~~$1.1479~~ | ~~$0.0101~~ | ~~$1.3171~~ | ~~$0.0728~~ | ~~$0.9078~~ | ~~$0.0342~~ | ~~$1.0148~~ | |
| **Commercial/Industrial - G-51** | | | | | | | | | |
| Customer Charge per Month per Meter | $50.00 | | | $50.00 | $50.00 | | | $50.00 | (I) |
| | ~~$24.81~~ | | | ~~$24.81~~ | ~~$24.81~~ | | | ~~$24.81~~ | |
| Size of the first block | 100 therms | | | | 100 therms | | | | |
| Therms in the first block per month at | $0.1103 | $1.1336 | $0.0099 | $1.2538 | $0.1103 | $0.9537 | $0.0336 | $1.0976 | |
| | ~~$0.2525~~ | ~~$1.1473~~ | ~~$0.0101~~ | ~~$1.4099~~ | ~~$0.2525~~ | ~~$0.9039~~ | ~~$0.0342~~ | ~~$1.1906~~ | |
| All therms over the first block per month at | $0.0712 | $1.1336 | $0.0099 | $1.2147 | $0.0712 | $0.9537 | $0.0336 | $1.0585 | |
| | ~~$0.1631~~ | ~~$1.1473~~ | ~~$0.0101~~ | ~~$1.3205~~ | ~~$0.1631~~ | ~~$0.9039~~ | ~~$0.0342~~ | ~~$1.1012~~ | |
| **Commercial/Industrial - G-52** | | | | | | | | | |
| Customer Charge per Month per Meter | $140.00 | | | $140.00 | $140.00 | | | $140.00 | (I) |
| | ~~$69.29~~ | | | ~~$69.29~~ | ~~$69.29~~ | | | ~~$69.29~~ | |
| Size of the first block | 1000 therms | | | | 1000 therms | | | | |
| Therms in the first block per month at | $0.1295 | $1.1336 | $0.0099 | $1.2730 | $0.0952 | $0.9537 | $0.0336 | $1.0825 | |
| | ~~$0.1734~~ | ~~$1.1473~~ | ~~$0.0101~~ | ~~$1.3308~~ | ~~$0.1275~~ | ~~$0.9039~~ | ~~$0.0342~~ | ~~$1.0656~~ | |
| All therms over the first block per month at | $0.0879 | $1.1336 | $0.0099 | $1.2314 | $0.0548 | $0.9537 | $0.0336 | $1.0421 | |
| | ~~$0.1177~~ | ~~$1.1473~~ | ~~$0.0101~~ | ~~$1.2751~~ | ~~$0.0734~~ | ~~$0.9039~~ | ~~$0.0342~~ | ~~$1.0115~~ | |
| **Commercial/Industrial - G-53** | | | | | | | | | |
| Customer Charge per Month per Meter | $600.00 | | | $600.00 | $ 600.00 | | | $ 600.00 | (I) |
| | ~~$300.00~~ | | | ~~$300.00~~ | ~~$300.00~~ | | | ~~$300.00~~ | |
| All therms over the first block per month at | $0.1116 | $1.1336 | $0.0099 | $1.2551 | $0.0534 | $0.9537 | $0.0336 | $1.0407 | |
| | ~~$0.1074~~ | ~~$1.1473~~ | ~~$0.0101~~ | ~~$1.2648~~ | ~~$0.0514~~ | ~~$0.9039~~ | ~~$0.0342~~ | ~~$0.9895~~ | |
| **Commercial/Industrial - G-54** | | | | | | | | | |
| Customer Charge per Month per Meter | $600.00 | | | $600.00 | $ 600.00 | | | $ 600.00 | (I) |
| | ~~$300.00~~ | | | ~~$300.00~~ | ~~$300.00~~ | | | ~~$300.00~~ | |
| All therms over the first block per month at | $0.0374 | $1.1336 | $0.0099 | $1.1809 | $0.0202 | $0.9537 | $0.0336 | $1.0075 | |
| | ~~$0.0799~~ | ~~$1.1473~~ | ~~$0.0101~~ | ~~$1.2373~~ | ~~$0.0410~~ | ~~$0.9039~~ | ~~$0.0342~~ | ~~$0.9791~~ | |
| ~~**Commercial/Industrial - G-63**~~ | | | | | | | | | |
| ~~Customer Charge per Month per Meter~~ | ~~$300.00~~ | | | ~~$300.00~~ | ~~$300.00~~ | | | ~~$300.00~~ | (D) |
| ~~All therms over the first block per month at~~ | ~~$0.0345~~ | ~~$1.1473~~ | ~~$0.0101~~ | ~~$1.1919~~ | ~~$0.0188~~ | ~~$0.9039~~ | ~~$0.0342~~ | ~~$0.9569~~ | |

## ~~II. RATE SCHEDULES~~

## ~~280 DAY SALES SERVICE~~

(D)

~~Availability~~
~~This service is applicable to commercial and industrial customers whose normal requirements are at least 5,000 therms per month provided that the Company has adequate delivery facilities and has an adequate supply of natural gas to meet the customer's requirements at that location. This rate is available only where the customer maintains alternate fuel capability.~~

~~Character of Service~~
~~Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet. Service is firm for a minimum of 280 days per year.~~

~~Rate~~

~~Customer Charge: $200.00 per month~~

~~This charge shall cover access to data from a remote meter reading system installed by the Company.~~

~~Commodity Charge:~~

~~This rate applicable to a customer's purchases in a given month shall be the oil parity rate as determined below.~~

~~Based on 1,000 Btu's per cubic foot and 100,000 Btu's per therm, the price to be paid for all gas consumed by a customer each month in which 280 Day Non Peak Firm Service is available will be a direct function of that customer's alternate fuel posted price as listed in the Platts Oilgram Report on Petroleum Prices. The posted price shall be the lowest quoted price at the Boston Terminal in tanker lots for #2 oil, #4 oil (1% sulfur), #6 oil (1% sulfur) and #6 oil (2-2.5% sulfur). The posted price of a customer's alternate fuel used in the 280 Day Service pricing formula will be determined on a monthly basis using an average of the daily posted prices for the four Fridays preceding the date upon which the Company must submit its nominations to Tennessee Gas Pipeline Company (Tennessee).~~

~~The percentages of posted price of oil to be used in computing 280 Day Non Peak Firm gas prices will be determined by the Company monthly. The percentage of the posted price of each alternate fuel may vary for those customers with the capacity to use more than 25,000 therms per month. The Company will report the percentages for various alternate fuel prices to the Public Utilities Commission at the beginning of each month. If the Commission questions the reasonableness of any such percentage determinations made by the Company, it may investigate the matter and, if necessary and appropriate, make such orders as are just and reasonable relative to percentage determinations that shall be applicable only to sales made by the Company after its receipt, and its notification to the customers affected, of such orders. The Company shall give such notification within three business days after its receipt of such orders.~~

~~The following calculations will be made to derive the prices to be charged per therm of 280 Day Non Peak Firm gas consumed:~~

~~**Rate 280-2**~~ ~~(alternate fuel - #2 oil)~~

~~$/therm = posted price/gallon (#2) x 100,000 x percentage of posted price of oil~~
~~140,000~~

**PROVISIONS DELETED**
**RESERVED FOR FUTURE USE**

Issued: February 25, 2008
Effective: August 24, 2008

Issued: By_______________________
Nickolas Stavropoulos
Title: President

~~**II. RATE SCHEDULES**~~

~~**280 DAY SALES SERVICE (Cont'd)**~~

(D)

~~**Rate 280-41** (alternate fuel - #4 oil [1% sulfur])~~

~~$/therm = posted price/barrel (#4 - 1%) x 100,000 x percentage of posted price of oil~~
~~145,000 x 42~~

~~**Rate 280-61** (alternate fuel - #6 oil [1% sulfur])~~

~~$/therm = posted price/barrel (#6 - 1%) x 100,000 x percentage of posted price of oil~~
~~150,000 x 42~~

~~**Rate 280-62** (alternate fuel - #6 oil [2 - 2.25% sulfur])~~

~~$/therm = posted price/barrel (#6 - 2.25%) x 100,000 x percentage of posted price of oil~~
~~150,000 x 42~~

~~At any time in which 280 Day Non Peak Service is not available, any gas consumed by a customer for pilot use will be combined with the customer's firm gas billing and billed under the Company's Large Volume 70 tariff.~~

~~This 280 Day Service Rate is not subject to the cost of gas rate.~~

~~The rates determined above are subject to the floor price defined below:~~

~~The floor price is defined as equaling the marginal cost of gas for the day of the sale adjusted to include: (a)$0.020 per therm; and (b) all applicable taxes.~~

~~The rate charged at any time during the year shall not be greater than the rate charged in accordance with the winter rate under the Company's Commercial/Industrial G-43 rate classification. For comparable usage, 280 sales margins shall not be less than 280 Day transportation margins, i.e., the rate charged to the customer less the floor price.~~

~~Terms and Conditions~~

~~A written service agreement (Service Agreement) on the Company's standard form shall be required. The service is also available in conjunction with the equivalent transportation service. The customer may elect to enter into concurrent interruptible sales and transportation contracts. Should the customer elect to do so, the customer must also elect on a monthly basis which service is to be utilized. In any event, the customer is only responsible for the payment of one service charge per month. The Service Agreement may contain limitations as to maximum hourly, daily or monthly consumption, provisions for notice of interruption and additional charges for excess usage, terms of payment and other terms and conditions of service. The customer must agree to discontinue gas service for a minimum of thirty (30) consecutive days per year. On or before November 1 of each year, the Company shall notify each 280 Day service customer of the starting and ending dates for the thirty (30) consecutive days of non-service for that year for that customer. The Company, at its sole option, may discontinue service for up to fifty-five (55) additional days during the Winter Period from November through April inclusive, upon twenty-four (24) hours notice. The Company will use its best efforts to provide the maximum notification of service disruption for the additional fifty-five (55) day period. The additional fifty-five (55) days of interruption need not be consecutive.~~

**PROVISIONS DELETED**
**RESERVED FOR FUTURE USE**

## ~~II. RATE SCHEDULES~~

## ~~280 DAY SALES SERVICE (Cont'd)~~

(D)

~~Customer shall pay its bills monthly. Any amounts not paid prior to the due date; normally the next meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one half percent (1½%) per month on the unpaid balance.~~

~~The customer must certify in a signed affidavit, appended to the contract, that the installation being served is physically and legally capable of burning the specific type of fuel oil used as the equivalent Btu determinant oil or other alternate fuel. The Company reserves the right, in its sole discretion, to waive the aforementioned affidavit upon good cause being shown by the customer. This service shall be limited in the Company's sole discretion to the operational systems and gas supply limitations of the Company. If a customer does not certify to the capability of burning a specific type of fuel oil, the customer's oil parity fuel price will be based on #2 fuel oil.~~

~~If incremental facilities, other than remote metering costs included in the customer charge, are required on the Company's system to serve the customer, the cost of such facilities shall be paid for by the customer. If the customer converts to this service from another customer service classification without satisfying payment of facilities costs in the Company's Service and Main Extension tariff, the costs unrecovered by the Company must be prepaid by the customer. The customer shall be required to have remote meter reading facilities.~~

~~280 Day Sales Service is not available in conjunction with Standby Sales Service.~~

~~The Company will compute the oil parity price and will notify each customer of the price for the month no less than five (5) business days prior to the first day of each month during the 280 Day firm period. The quoted price shall be fixed during each firm service month subject to the floor price provision of this tariff. During the 280 Day period of firm service, the Company may, in extraordinary circumstances, adjust the quoted price upward in the unlikely event that the floor price, for unanticipated reasons, rises above the price quoted for the month. For the fifty-five (55) days of potential additional service, daily price quotes will be provided to the customer by the Company not less than twenty-four (24) hours in advance. The quoted price during the fifty-five (55) day period shall not be less than the floor price provisions of this tariff.~~

~~Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification except as specified herein. The Company shall be afforded the opportunity by the customer to inspect the facilities to properly ascertain the gas-using capacity and alternate fuel capability on the customer's premises.~~

~~It is the customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times.~~

~~If a customer requests gas on an emergency basis when gas service would otherwise be precluded under this service classification, the Company may, in its sole discretion, tender gas if it determines that an emergency does exist and the Company has the ability to provide the gas service. Gas consumed under this provision will be priced at a rate per therm equal to the highest cost of gas, as determined by the Company, during the time such service is rendered, adjusted for the applicable taxes and assessments, plus the Industrial General firm sales delivery rate.~~

~~The customer shall pay for any unauthorized gas usage at the rate of One Dollar and Fifty Cents ($1.50) per therm.~~

~~Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.~~

**PROVISIONS DELETED**
**RESERVED FOR FUTURE USE**

## II. RATE SCHEDULES

## 280 DAY TRANSPORTATION SERVICE (Cont'd)

Terms and Conditions

Customers taking service under this rate schedule will be subject to the terms and conditions of Delivery Service, Section 9 - Daily Metered Delivery Service, of the Company's Delivery Tariff.

A written 280 Day service agreement (Service Agreement) on the Company's standard form for a minimum period, as defined in the Service Agreements, shall be required for 280 Day service. The Company will make service available under this tariff within sixty (60) days of receipt of the completed Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily or monthly consumption, provisions for notice of interruption and additional charges for excess usage, terms of payment and other terms and conditions of service.

Customer shall pay its bills monthly. Any amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed, are subject to a late payment charge of one and one half percent (1½%) per month on the unpaid balance.

It is the customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times.

The customer must certify in a signed affidavit, appended to the contract, that the installation being served is physically and legally capable of burning an alternate fuel. The Company reserves the right, in its sole discretion, to waive the aforementioned affidavit upon good cause being shown by the customer. This service shall be limited in the Company's sole discretion to the operational systems and of the Company.

If incremental facilities, other than remote metering costs included in the customer charge, are required on the Company's system to serve the customer, the cost of such facilities shall be paid for by the customer. If the customer converts to this service from another customer service classification without satisfying payment of facilities costs in the Company's Service and Main Extension tariff, the costs unrecovered by the Company must be prepaid by the customer. The customer shall be required to have remote meter reading facilities.

The customer must agree to discontinue gas service for a minimum of thirty (30) consecutive days per year. On or before November 1 of each year, the Company shall notify each 280 Day transportation customer of the starting and ending dates for the thirty (30) consecutive days of non-service for that year for that customer. The Company, at its sole option, may discontinue service for up to fifty-five (55) additional days during the Winter Period from November through April inclusive upon twenty-four (24) hours notice. The Company will use its best efforts to provide the maximum notification of service disruption for the additional fifty-five (55) day period. The additional fifty-five (55) days of interruption need not be consecutive.

If a customer requests gas on an emergency basis when gas service would otherwise be precluded under this service classification, the Company may, in its sole discretion, tender gas if it determines that an emergency does exist and the Company has the ability to provide the gas service. Gas consumed under this provision will be priced at a rate per therm equal to the highest cost of gas, as determined by the Company, during the time such service is rendered, adjusted for the applicable taxes and assessments, plus the Industrial General firm sales delivery rate.

The customer shall pay for any unauthorized gas usage at the rate of ~~One Dollar and Fifty Cents ($1.50) per therm~~five times the daily index. (I)

## II. RATE SCHEDULES

## 280 DAY TRANSPORTATION SERVICE (Cont'd)

Balancing
The customer shall be responsible for balancing with the interstate pipeline its upstream (prior to the city gate) daily nominations with daily takes. The customer shall provide nominations to the Company as provided in the Delivery Terms & Conditions. ~~Service Agreement. The terms, conditions and charges for balancing are detailed in the Service Agreement.~~ (T)

Measurement
Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification except as specified herein. The Company shall be afforded the opportunity by the customer to inspect the facilities to properly ascertain the gas-using capacity and alternate fuel capability on the customer's premises.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

## II. RATE SCHEDULES

### INTERRUPTIBLE TRANSPORTATION SERVICE - ITS (Cont'd)

Terms and Conditions
Customers taking service under this rate schedule will be subject to the terms and conditions of Delivery Service, Section 9 - Daily Metered Delivery Service, of the Company's Delivery Tariff.

A written interruptible service agreement (Service Agreement) on the Company's standard form for a minimum period, as defined in the Service Agreements, shall be required for Interruptible Transportation service. The Company will make service available under this tariff within sixty (60) days of receipt of the completed Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily or monthly consumption, provisions for notice of interruption and additional charges for excess usage, terms of payment and other terms and conditions of service.

Customer shall pay its bills monthly. Any amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed, are subject to a late payment charge of one and one half percent (1½%) per month on the unpaid balance.

It is the customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times.

The customer must certify in a signed affidavit, appended to the contract, that the installation being served is physically and legally capable of burning an alternate fuel. The Company reserves the right, in its sole discretion, to waive the aforementioned affidavit upon good cause being shown by the customer. This service shall be limited in the Company's sole discretion to the operational systems of the Company.

If incremental facilities, other than remote metering costs included in the customer charge, are required on the Company's system to serve the customer, the cost of such facilities shall be paid for by the customer. If the customer converts to this service from another customer service classification without satisfying payment of facilities costs in the Company's Service and Main Extension tariff, the costs unrecovered by the Company must be prepaid by the customer. The customer shall be required to have remote meter reading facilities.

If a customer requests gas on an emergency basis when gas service would otherwise be precluded under this service classification, the Company may, in its sole discretion, tender gas if it determines that an emergency does exist and the Company has the ability to provide the gas service. Gas consumed under this provision will be priced at a rate per therm equal to the highest cost of gas, as determined by the Company during the time such service is rendered, adjusted for the applicable taxes and assessments, plus the Industrial General firm sales delivery rate.

(I)

The customer shall pay for any unauthorized gas usage at the rate of ~~One Dollar and Fifty Cents ($1.50) per therm~~five times the daily index.

Balancing
The customer shall be responsible for balancing with the interstate pipeline its upstream (prior to the city gate) daily nominations with daily takes. The customer shall provide nominations to the Company as provided ~~in the Service Agreement. The terms, conditions and charges for balancing are detailed in the Service Agreement.~~Delivery Terms and Conditions. (T)

Measurement
Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification except as specified herein. The Company shall be afforded the opportunity by the customer to inspect the facilities to properly ascertain the gas-using capacity and alternate fuel capability on the customer's premises.
Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the New Hampshire Public Utilities Commission.

9 DAILY METERED DELIVERY SERVICE

9.1 Applicability

Section 9 of this tariff shall be applicable in the following conditions:

9.1.1 All Customers whose service may be interrupted at any time during the year shall be required to take daily metered Delivery Service.

9.1.2 Any Customer, regardless of annual Gas Usage, may elect daily metered Delivery Service.

9.1.3 ***Customers under Rate Schedules G-43, G-53, and G-54 ~~and G-63~~ wishing to take Delivery Service are required to take Daily Metered Delivery Service. In addition,*** the Company may require a Customer to take daily metered Delivery Service if the Company determines that the daily Gas Usage characteristics of the Customer cannot be accurately modeled using the Company's Consumption Algorithm or if the volumes reasonably anticipated by the Company to be used by the Customer are of a size that may materially affect the integrity of the Company's distribution system. (D)

9.2 Delivery Service Provided

This service provides delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day. For Customers taking Delivery Service under Rate Schedules ***G-43, G-53, and G-54*** ~~***and G-63,***~~ this service provides firm, year-round delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point. (D)

9.3 Nominations and Scheduling of Service

9.3.1 The Supplier is responsible for nominating and delivering to the Designated Receipt Point(s) every Gas Day an amount of Gas that equals the aggregated Gas Usage of Customers in the Aggregation Pool plus the Company Gas Allowance in accordance with Section 8 of this tariff.

9.3.2 Nominations shall be communicated to the Company by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means.

9.3.3 Nominations for the first Gas Day of a Month shall be submitted to the Company no later a separate pool from Customers subscribing to daily metered service under Rate Schedules G-43, G-53, and G-54 ~~and G-63~~. (D)

20.6.2 Non-daily metered Customers taking Delivery Service pursuant to Section 10 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Gas Service Areas.

20.6.3 Daily metered Customers taking Delivery Service pursuant to Section 9 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Gas Service Areas.

20.6.4 A separate Supplier account will be established for each Supplier Aggregation Pool.

20.6.5 The election of any service from the Company by the Supplier shall apply to the entire Aggregation Pool and not just an individual customer in the Aggregation Pool.

20.6.6 The Company may charge a monthly fee to the Supplier for each Aggregation Pool pursuant to Attachment D.

20.7 Imbalance Trading

20.7.1 Prior to the imposition of imbalance charges, the Supplier may engage in trading daily and monthly imbalances for the previous Month, provided that daily imbalance trades are communicated to the Company within three (3) Business Days upon the Company's provision of information on Supplier imbalances for said Month.

20.7.2 The Company will make available a list of Suppliers by Gas Service Area making deliveries during the previous Month.m

20.7.3 Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company.

20.7.4 Daily imbalance trades must be point-specific on those Gas Days when the Transporting Pipeline required the Company to balance on a point-specific basis.

20.8 Billing and Payment

20.8.1 By the tenth (10th) Business Day of the calendar month, the Company shall render to the Supplier a statement of the quantities delivered and amounts owed by the Supplier for the

(D)

# ~~ENERGYNORTH NATURAL GAS, INC.~~
# ~~d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND~~

# ~~280 DAY SALES~~

# ~~SERVICE AGREEMENT~~

# PROVISIONS DELETED
# RESERVED FOR FUTURE USE

~~ENERGYNORTH NATURAL GAS, INC.~~

~~280 DAY SERVICE AGREEMENT~~

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~~ENERGYNORTH NATURAL GAS, INC.~~

~~280 DAY SERVICE AGREEMENT~~

(D)

~~ARTICLE I~~

~~PREAMBLE~~

~~This agreement (Agreement) is made this ______ day of ________, 19__ by and between EnergyNorth Natural Gas, Inc., d/b/a/ KeySpan Energy Delivery New England a New Hampshire corporation with its principal place of business at 1260 Elm Street, Manchester, New Hampshire 03105 (Company), and ________________________________, a _____________ corporation with its principal place of business at ____________________________________ (Customer).~~

~~WHEREAS, Customer has requested gas service pursuant to the terms and conditions of the Company's 280 Day Service Tariff as authorized by the New Hampshire Public Utilities Commission;~~

~~WHEREAS, the Customer's normal gas requirements consumed under this rate will be at least 5,000 therms per month; and~~

~~WHEREAS, the Company is willing to provide such gas service to Customer at Customer's facility located at ___________________________________________ (Customer's Facility);~~

~~NOW THEREFORE, in consideration of the mutual covenants and agreements contained herein, and subject to the laws and regulations of the State of New Hampshire, the parties do covenant and agree as follows:~~

~~ARTICLE II~~

~~GOVERNING LAW~~

~~This agreement shall be subject to the General Laws of the State of New Hampshire and the Terms and Conditions as authorized from time to time by the New Hampshire Public Utilities Commission (the Commission), to the extent such terms and conditions apply to the provision of gas service pursuant to this Agreement In the event of a conflict between said Terms and Conditions applicable to the 280 Day Service Tariff and the provisions of this agreement, the tariff shall govern. This agreement shall be further subject to any Commission order affecting the provision of 280 Day Service~~

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~~ARTICLE III~~

~~GAS TO BE SOLD.~~

~~3.1 Gas Sales Quantity~~ (D)

~~The Company agrees to sell and deliver and Customer, in months where the gas rate is competitive, agrees to purchase and receive monthly at least 5,000 therms of gas at Customer's Facility. The sale and purchase of gas herein is subject to the terms and conditions of this Agreement, the Company's 280 Day Service Tariff, incorporated by this reference, which is attached hereto and identified as Schedule A.~~

~~3.2 Character of Service~~

~~Delivery of gas hereunder is subject to curtailment or interruption as defined in the 280 Day Service Tariff. Such curtailment or interruption may be required by Company due to curtailment of its supply for the protection of deliveries of firm gas.~~

~~Customer agrees to discontinue gas service for at least 30 consecutive days per year and acknowledges that the Company may in its discretion, discontinue service for an additional fifty-five days as provided in the 280 Day Service Tariff.~~

~~3.3 Standby Equipment and Fuel.~~

~~It is understood and agreed that the Customer's right to purchase and to receive and to continue to purchase and receive gas under the terms of this Agreement is and shall be entirely dependent upon Customer having an alternate fuel supply available for use upon not less than twenty-four (24) hours prior notice. The Company shall notify Customer on or before November 1 of each year of the period gas service will be discontinued for the thirty (30) consecutive days. Service may also be discontinued for an additional fifty-five (55) days during the period November 1 through March 31 (Winter Period) upon at least twenty-four (24) hours notice. The Company agrees to give Customer as much notice is as reasonably possible of such additional discontinuance of this service during the Winter Period.~~

~~Customer understands that the 280 Day Service Rate is not available in conjunction with the Standby Service Rate.~~

~~Customer's failure to comply with a notice by Company for curtailment, pursuant to the provisions of Article III, paragraph 3.2, shall be considered sufficient cause~~

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~~for Company, at its option, to cancel this Agreement without further notice and terminate gas service to Customer. In all circumstances, Customer shall be obligated to pay for gas used pursuant to the terms of this Agreement.~~

~~3.4 Inspection of Customer's Facility~~

(D)

~~Customer shall permit Company to inspect Customer's facilities to determine its gas-using capacity and alternate fuel capability. Customer acknowledges that it is Customer's sole responsibility to ensure that its alternate fuel and equipment is adequate to meet is requirements.~~

~~3.5 Penalty for Unauthorized Use of Gas.~~

~~Any use of gas by Customer during a period of interruption or curtailment, as set forth in Article III, paragraphs 3.2 and 3.3 herein, shall be referred to as unauthorized use of gas. For all unauthorized use of gas by Customer on any day during the billing month, Customer shall pay Company a penalty of $1.50 per Therm for each Therm taken. Such penalty shall not preclude Company from shutting off Customer's supply of gas in the event of Customer's failure to curtail his use thereof when requested by Company to do so.~~

~~ARTICLE IV~~

~~RATE SCHEDULE AND CHARGES~~

~~4.1 Rate for Gas Sales.~~

~~For gas delivered hereunder, Customer shall pay the rate as determined pursuant to the 280 Day Service Tariff. Such rate includes system losses and franchise taxes. Company may file new or amended rate tariffs with the Public Utilities Commission to reflect, among other things, changes in the cost of purchased gas and increased operating costs and Customer acknowledges that the Commission, on its own authority, may order changes in such rate.~~

~~Customer reserves the right to file complaints, protest any proposed changes in rates or service provided by Company, participate in any proceedings before the Public Utilities Commission, or take such other action as may be in Customer's best interests with regard to the services contemplated herein. Company agrees to furnish copies to Customer of all filings, proposals and other changes submitted to the Public Utilities Commission which will affect the Company's 280 Day Service Tariff, upon written request of the Customer.~~

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~~For the purpose of determining rates, Customer's alternate fuel is #_ oil, having a sulphur content of _____ percent (_____%).~~

~~4.2 Company shall notify Customer of the price of gas for any month during the firm 280 day period not less than five (5) business days prior to the first day of the month. The price can be adjusted during the month as provided in the 280 Day Service Tariff~~ (D)

~~4.3 Company shall notify Customer of the price of gas during the fifty-five (55) day Winter Period of potential discontinuance of service on a daily basis. Customer shall be notified of the daily price at least twenty-four (24) hours in advance.~~

~~4.4 Billing and Payment.~~

~~Customer shall pay its bills monthly by the tenth of each month following receipt of the bill (Due Date). A late charge will be assessed if payment has not been received by the fifteenth of the month following the Due Date. In addition to the late fee, if Customer fails to pay in full by the 15th of the month after the Due Date, interest charges at the rate of one and one-half percent (1 1/2%) per month, measured from the Due Date on the unpaid balance until paid in full, shall be assessed. Customer agrees to pay any such interest and late payment charges. Invoices not paid within thirty (30) days shall constitute an Event of Default as defined in paragraph 5. 7 of the Agreement, except that Company may discontinue service to Customer without further notice.~~

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~~ARTICLE V~~

~~MISCELLANEOUS PROVISIONS~~

(D)

~~5. 1 Deposit.~~

~~For the purposes of determining whether deposits will be required, Company expects Customer to pay monthly invoices in accordance with the provisions stated in Schedule A, Payment Terms. Company may require a security deposit if Customer fails to comply with these provisions. If and when requested by the Company, Customer will promptly make a security deposit in the amount requested, which deposit shall not exceed the larger of (a) two months' estimated bills for gas during the period of Customer's highest recorded consumption of gas, and (b) the largest amount of any outstanding indebtedness at any time during the two preceding years.~~

~~5.2 Term.~~

~~This Agreement shall be effective for a term of one year from the date of execution, and shall thereafter continue from year to year unless canceled by written notice given by either party to the other at least 45 days before the expiration of the term then in effect.~~

~~5.3 Notices.~~

~~Notices to Company under this Agreement shall be addressed as follows:~~

~~EnergyNorth Natural Gas, Inc.~~
~~201 Rivermoor Street~~
~~West Roxbury, MA 02132~~
~~Attn.: Elizabeth Danehy~~
~~Director, Customer Choice and Energy Supply~~

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~~Notices to Customer shall be addressed as follows:~~

(D)

~~Invoices and curtailment notices to Customer shall be addressed as follows:~~

~~Either party may change its address under this section at any time upon prior written notice to the other party.~~

~~5.4 Cancellation of Previous Contract.~~

~~This Agreement supersedes and cancels, as of the effective date hereof, any previous contract between the parties hereto for the sale of gas by Company to Customer for its gas requirements at Customer's facility, but without affecting any obligation of either party to the other which shall have accrued prior to the effective date of this Agreement.~~

~~5.5 Succession and Assignment.~~

~~No assignment of this Agreement or of any right or obligation hereunder shall be made by Customer or Company without the prior written consent of the other first obtained, which consent shall not be unreasonably withheld. This Agreement and each of its terms shall be binding upon, and inure to the benefit of, the respective successors and assigns of the parties hereto.~~

~~5.6 Interpretation.~~

~~(a) This Agreement and the respective obligations of the parties hereunder are subject to all valid laws, orders, rules and regulations of duly constituted New Hampshire authorities having jurisdiction.~~

~~(b) This Agreement, together with the Schedules attached hereto, constitute the entire understanding and agreement between the parties and may not be modified except by a writing signed by both parties. Any duly executed modifications or amendments shall become part of this Agreement.~~

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~~5.7 Default.~~

~~Any one of the following events shall constitute an Event of Default:~~

~~(a) If Customer shall default in the due and punctual payment for gas service as and when due, as determined by this Agreement and the Tariff; or~~ (D)

~~(b) If Customer, in keeping, observing or performing any other terms, conditions or covenants in this Agreement; or~~

~~(c) No term, condition or covenant of this Agreement may be waived except by written consent of the Parties hereto. Forbearance by either party of a term, condition or covenant shall not constitute a waiver of the same.~~

~~Accordingly, the parties hereto have executed this Agreement.~~

~~ENERGYNORTH NATURAL GAS, INC.~~

~~By:~~ ____________________ ~~Attest:~~____________________

~~Vice President~~

____________________

~~By:~~ ____________________ ~~Attest:~~____________________

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~~**ENERGYNORTH NATURAL GAS, INC.**~~
~~**280 DAY SERVICE TARIFF**~~
~~**SCHEDULE A**~~

~~**280 DAY SERVICE**~~ (D)

~~**Availability**~~
~~This service is applicable to commercial and industrial customers whose normal requirements are at least 5,000 therms per month provided that the Company has adequate distribution facilities and has an adequate supply of natural gas to meet the customer's requirements at that location. This rate is available only where the customer maintains alternate fuel capability.~~

~~**Character of Service**~~
~~Natural gas or equivalent will be supplied at a heat content value of nominally (1) therm in each one hundred (100) cubic feet.~~
~~Firm service for a minimum of 280 days per year.~~

~~**Rate**~~

~~**Customer Charge**: $200.00 per month~~

~~This charge shall cover access to data from a remote meter reading system installed by the Company.~~

~~**Commodity Charge**:~~

~~The rate applicable to a customer's purchases in a given month shall be the oil parity rate as determined below.~~

~~Based on 1,000 Btu's per Cubic Foot and 100,000 Btu's per therm, the price to be paid for all gas consumed by a customer each month in which 280 Day Non Peak Firm Service is available will be a direct function of that customer's alternate fuel posted price as listed in the Platts Oilgram Report Petroleum Prices. The posted price shall be the lowest quoted price at Boston Terminal in tanker lots for #__ oil, #__ oil (__% sulphur), #__ oil (__% sulphur) and #__ oil (__-____% sulphur). The posted price of a customer's alternate fuel used in the 280 Service pricing formula will be determined on a monthly basis using an average of the daily posted prices for the four Fridays preceding the date upon which the Company must submit its nominations to Tennessee Gas Pipeline Company (Tennessee).~~

~~The percentages of posted price of oil to be used in computing 280 Day Non Peak Firm gas prices will be determined by the Company monthly. The percentage of the posted price of each alternate fuel may vary for those~~

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~~customers with the capacity to use more that 25,000 therms per month. The Company will report the percentages for various alternate fuel prices to the Public Utility Commission at the beginning of each month. If the Commission questions the reasonableness of any such percentage determinations made by the Company, it may investigate the matter and, if necessary and appropriate, make such orders as are just and reasonable relative to percentage determinations that shall be applicable only to sales made by the Company after its receipt, and its notification to the customers affected, of such orders. The Company shall give such notification within three business days after its receipt of such orders.~~ (D)

~~The following calculations will be made to derive the prices to be charged per therm of 280 Day Non Peak Firm gas consumed:~~

~~**Rate 280-2** (alternate fuel - #2 oil)~~

~~$ / therm = Posted Price/gal. (#2) x 100,000 x Percentage of posted price of oil~~
~~140,000~~

~~**Rate 280-41** (alternative fuel - #4 oil - 1% sulphur)~~

~~$ / therm = Posted Price/brl (#4 - 1%) x 100,000 x Percentage of posted price of oil~~
~~145,000 x 42~~

~~**Rate 280-61** (alternate fuel - #6 oil - 1% sulphur)~~

~~$ / therm = Posted Price/brl (#6 - 1%) x 100,000 x Percentage of posted price of oil~~
~~150,000 x 42~~

~~**Rate 280-62** (alternate fuel - #6 oil - 2-2.5% sulphur)~~

~~$ / therm = Posted Price/brl (#6 - 2.25% x 100,000 x Percentage of posted price of oil~~
~~150,000 x 42~~

~~Rate 280-2, 280-41, 280-61, and 280-62 will be divided by .968 (to cover the 1% franchise tax and 2.2% lost and unaccounted for gas) to arrive at the prices to be charged.~~

~~At any time in which 280 Day Non Peak Firm Service is not available, any gas consumed by a customer for pilot use will combined with the customer's firm gas billing and billed under the Company's Large Industrial Rate tariff.~~

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~~This 280 day rate is not subject to the cost of gas adjustment.~~

~~The rates determined above are subject to the floor price defined below:~~

(D)

~~The Floor Price is defined as equaling the Marginal Cost of Gas for the day of sale adjusted to include:~~

~~a) the effect of system losses estimated to be 2.2 percent; and~~
~~b) franchise taxes.~~

~~The rate charged at any time during the year shall not be greater than the rate charged in accordance with the winter rate under the Company's Large Industrial Rate.~~

~~**Terms and Conditions**~~
~~To be eligible for this service a customer must sign a contract for a one year period for 280 day service which contract may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for notice of interruption and additional charges for excess usage, terms of payment, and other terms and conditions of service. The customer must agree to discontinue gas service for a minimum of 30 consecutive days per year. On or before November 1 of each year, the Company shall notify each 280 day service customer of the starting and ending dates for the 30 consecutive days of non service for that year for that customer. The Company at its sole option may discontinue service for up to 55 additional days during the winter period from November through March inclusive upon 24 hours notice. The Company will use its best efforts to provide the maximum notification of service disruption for the additional 55 day period. The additional 55 days of interruption need not be consecutive.~~

~~The customer must certify in a signed affidavit, appended to the contract, that the installation being served is physically and legally capable of burning the specific type of fuel oil used as the equivalent BTU determinant oil or other alternate fuel. The Company reserves the right in its sole discretion to waive the aforementioned affidavit upon good cause being shown by the customer. This service shall be limited in the Company's sole discretion to the operational systems and gas supply limitations of the Company. If a customer does not certify to the capability of burning a specific type of oil, the customer's oil parity fuel price will be based on #2 fuel oil.~~

~~280 day~~ 0~~service is not available in conjunction with standby service.~~

~~The Company will compute the oil parity price and will notify each customer of the price for the month no less than five business days prior to the first day of each month during the 280 day firm period. The quoted price shall be fixed during each firm service month subject to the floor price provision of this tariff. During the 280 day period of firm service the Company may, in extraordinary circumstances, adjust the quoted price upward in the unlikely event that the floor price, for unanticipated reasons, rises above the price quoted for the month. For the 55 days of potential additional service daily~~

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~~price quotes will be provided to the customer by the Company not less than 24 hours in advance. The quoted price during the 55 day period shall not be less than the floor price provisions of this tariff.~~

~~Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification. The Company shall be afforded the opportunity by the customer to inspect the facilities to properly ascertain the gas-using capacity and alternate fuel capability on the customer's premises.~~ (D)

~~It is the customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times.~~

~~Prior to supplying gas under this rate classification, the Company must have in its possession a fully executed contract between the parties. Service is governed by Company's Standard Terms and Conditions and by the terms and conditions of the contract.~~

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(D)

~~STATE OF NEW HAMPSHIRE )~~
~~COUNTY OF______________________ ) AFFIDAVIT~~
~~)~~

~~______________________, a resident of ______________ in the State of New Hampshire, being duly authorized by ____________________________________________________________, New Hampshire, a New Hampshire corporation with a principal place of business at ________ ___________________________, New Hampshire, being first duly sworn according to law deposes and says that:~~

~~1) __________________________________ requests natural gas service at ________ _________________, ________, NH, at which has normal gas fuel requirements of 5,000 therms per month;~~

~~2) __________________________________ has alternate fuel capability which is adequate to meet its energy needs at ________________________, ________, New Hampshire;~~

~~__________________________________ has not relied upon or received any representations by EnergyNorth Natural Gas, Inc. regarding the adequacy of its alternate fuel capability;~~

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~~3)~~

~~6)The alternate fuel of ______________________________ is #6 fuel oil having a sulphur content of 2-2.5 percent (2-2.5%), which alternate fuel is capable of being burned in the equipment at Customer's facilities; and~~ (D)

~~7) ____________________________________ is physically and legally capable, including but not limited to having the appropriate standby equipment and all necessary permit and authorizations, to burn the alternate fuel identified in the preceding paragraph.~~

~~DATED this ___ day of ______, _____.~~

______________________________________

~~By: ___________________________________~~
~~___________________, DULY AUTHORIZED~~

~~STATE OF ______________________~~
~~COUNTY OF ____________________~~

~~The foregoing instrument was acknowledged before me this ______ day of __________, _____ by ______________________, the ___________________ of _________________________________ a, __________________________ corporation, being duly authorized.~~

__________________________________
~~Notary Public/Justice of the Peace~~

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~~ENERGYNORTH NATURAL GAS, INC.~~ (D)

~~d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND~~

~~280 DAY TRANSPORTATION~~

~~SERVICE AGREEMENT~~

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**~~ENERGYNORTH NATURAL GAS, INC.~~**

**~~280 DAY TRANSPORTATION SERVICE AGREEMENT~~**

(D)

~~ARTICLE I.~~

~~PREAMBLE~~

~~This agreement is made this _____ day of _________, ____ by and between EnergyNorth Natural Gas, Inc.,d/b/a KeySpan Energy Delivery New England, a New Hampshire corporation with its principal place of business at 1260 Elm Street, Manchester, New Hampshire 03105 (Company), and ____________________ a __________________ corporation with its principal place of business at ________________________________________________ (Customer).~~

~~Service under this agreement will commence (as defined by EnergyNorth Natural Gas, Inc.) on the ____day of _________, ______and shall be referred to as the effective date of service.~~

~~WITNESSETH:~~

~~WHEREAS, Customer owns or has access to volumes of natural gas which can be delivered through the Tennessee Gas pipeline system (Transportation Pipeline) which it desires to have transported to its facility located at ________________________________________________ (Customer's Facility); and~~

~~WHEREAS, Company is willing to receive, transport and deliver such gas to Customer at Customer's facility;~~

~~NOW THEREFORE, in consideration of the mutual covenants and agreements contained herein, and subject to the laws and regulations of the State of New Hampshire, the parties do covenant and agree as follows:~~

~~ARTICLE II.~~

~~GOVERNING LAW~~

~~This agreement shall be subject to the General Laws of the State of New Hampshire and the Terms and Conditions as authorized from time to time by the New Hampshire Public Utilities Commission (the Commission), to the extent such terms and conditions apply to the transportation of natural gas or other terms and conditions of service. In the event of a conflict between said Terms and Conditions applicable to transportation services and the provisions of this agreement, this agreement shall govern. This agreement shall be further subject to any Commission order affecting transportation service.~~

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## ~~ARTICLE III.~~

## ~~DEFINITIONS~~

~~**Daily Metered Quantity** - The actual quantity of gas used by the Customer during the Gas Day as measured by the Company's metering equipment at the Delivery Point.~~ (D)

~~**Daily Overtake Quantity** - An Imbalance in which the difference between the Daily Metered Quantity and the Daily Scheduled Quantity is a positive number, i.e., where Daily Metered Quantity exceeds the Daily Scheduled Quantity.~~

~~**Daily Scheduled Quantity** - The quantity of gas scheduled to be received during the Gas Day by the Company at the Receipt Point for the account of Customer, for redelivery at the Delivery Point during the same Gas Day.~~

~~**Daily Undertake Quantity** - An Imbalance in which the difference between the Daily Metered Quantity and the Daily Scheduled Quantity is a negative number, i.e., where Daily Metered Quantity is less than the Daily Scheduled Quantity.~~

~~**Delivery Point** - A location where the Company's distribution facilities are interconnected with the Customer's facility and where the Customer's gas will be delivered by the Company.~~

~~**Gas Day** - A period of twenty-four (24) consecutive hours beginning at 10:00 a.m. E.T., and ending at 10:00 a.m., the next calendar day.~~

~~**Imbalance** - The difference, during the Gas Day, between the Daily Scheduled Quantity and Daily Metered Quantity.~~

~~**Marginal Cost** - The variable cost of the Company's marginal source of gas, including variable Transportation Pipeline charges, for the Gas Day.~~

~~**Maximum Daily Quantity (MDQ)** - The maximum gas quantity which Customer has a right to use and the Company is obligated to deliver during any Gas Day. The quantity shall be no greater than the Customer's hourly connected load times twenty-four (24) hours.~~

~~**Receipt Point** - An interconnection between the Customer's Transporting Pipeline and the distribution facilities of the Company where gas will be received by the Company for transportation in its service territory.~~

~~**Swing Tolerance Level** - The daily Imbalance allowance between the Daily Scheduled Quantity and the Daily Metered Quantity at the Delivery Point. The default level will be ± 10%, but can be adjusted by the Company only if Tennessee Gas Pipeline (TGP) imposes tighter tolerance levels (i.e., TGP may issue an Operational Flow Order (OFO) restricting the Company to a tighter swing tolerance level). Notice will be given to customers before any changes are made to the swing tolerance level as defined in Article X, Paragraph G.~~

~~**Transportation Pipeline** - The person(s), Company(ies) or other party(ies), engaged in the business of rendering transportation service of natural gas in interstate commerce, subject to the jurisdiction of the Federal Energy Regulatory Commission, which the person(s),~~

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~~Company(ies) or party(ies) is (are) transporting gas for Customer's account to the Receipt Point of the distribution facilities of the Company.~~

~~ARTICLE IV.~~

(D)

~~SERVICE TO BE PROVIDED BY COMPANY~~

~~A. Company will receive from Customer, at the Receipt Point designated in Exhibit A, volumes of natural gas up to a Maximum Daily Quantity (MDQ) as defined in Exhibit A of this agreement, subject to its rights under Article IV, Paragraph (C), hereunder. Company will use its best efforts to transport this MDQ of natural gas to Customer at Customer's Facility.~~

~~B. Transportation service will be provided on a best efforts basis and will be subject to interruption and/or curtailment to the extent the Company determines in its sole judgment such interruption to be necessary to ensure continued service to the Company's firm sales and firm transportation customers. All curtailments or interruptions by Company will be made in accordance with Article XI and the Company's Supply and Capacity Shortage Allocation Policy. Delivery of the gas is not subject to curtailment or interruption during the 280 days of firm service except pursuant to the Company's Gas Shortage Allocation Policy. Delivery of gas is subject to curtailment or interruption for a consecutive thirty (30) day period and for the remaining fifty-five (55) days as notified.~~

~~C. Company will give Customer at least two hours advance notice by telephone of any such curtailment or interruption at Customer's telephone number(s) as defined in Exhibit A(and Customer shall be available to receive such notice twenty four (24) hours a day, seven (7) days a week. Upon receipt of such notice, Customer shall curtail or discontinue the use of gas from the delivery point within two hours. In the event of a major system failure, Customer agrees to discontinue gas use as soon as possible after notification from Company. In the event of any failure to curtail or discontinue gas use, Customer will pay Company an additional charge of One Dollar and Fifty Cents ($1.50) for all unauthorized gas use after the conclusion of the two hour notification period. Notwithstanding any payment of such additional charge, Company may discontinue transportation service to Customer if Customer fails to comply with its obligations to discontinue use in accordance with the provisions of this contract, which failure by Customer shall constitute an Event of Default as defined in Article XII.~~

~~D. Insofar as practicable, Customer shall arrange for transportation quantities at a uniform rate throughout the day.~~

~~E. The Receipt Point(s) at the Company's city gate set forth in Exhibit A may be changed only by mutual agreement. Customer shall include any proposed changes in the Company's city gate Receipt Point(s) with its nomination submitted for service on the first day of a given month. Company reserves the right to reject such proposed changes.~~

~~F. It is understood that Company has no obligation to provide service under this agreement other than on the basis described above. Customer warrants and agrees that it shall maintain complete alternate standby fuel and equipment available for use in the event of curtailment or interruption of service. Customer agrees that Company has the right to inspect such equipment, but not an obligation to inspect nor to ensure that such standby equipment is adequate for Customer's requirements.~~

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~~Notwithstanding the foregoing, the Company shall not be liable to Customer or to Customer's customers for any loss or damage incurred by Customer resulting from (a) any curtailment or interruption, including a permanent interruption in the delivery of the transportation volume, whether or not notice of such curtailment or interruption is given; or (b) any variation in the quality or pressure of the transportation volume delivered.~~ (D)

~~G. Nothing herein shall be construed as obligating Company to construct additional facilities. If new or additional facilities are required on the Company's system for Customer to receive 280 day transportation service, Customer shall prepay for the facilities.~~

~~If Customer converts to this service from another service classification without satisfying payment of facilities costs in the Company's Service and Main Extension tariff, the costs of facilities unrecovered by the company must be prepaid by the customer.~~

~~H. The Company's As Available Gas Supply Service is available in conjunction with this 280 day transportation service on any day that 280 Day Transportation Service is available.~~

~~I. In the event the Company, during a curtailment or interruption, requires emergency gas, and takes the gas of Customer, Customer shall be compensated for such emergency gas at the Customer's alternate cost of fuel as demonstrated to the reasonable satisfaction of the Company.~~

~~ARTICLE V.~~

~~CUSTOMER RESPONSIBILITIES~~

~~A. Customer shall provide Company with a written nomination, with information sufficient for the Company to confirm nominations, substantially identical to Exhibit B1, stating the maximum volume to be transported by Company during the next day. Such nominations must be received on or before 10:00 a.m. of each Gas Day, unless a standing nomination for each Gas Day has been received twenty-four (24) hours before the interstate pipeline nominations are due for the month, in order to be effective for the next day, provided, however, that earlier nominations may be required. Company will notify Customer if an earlier nomination deadline is required by another transporter. If no nomination is made by Customer with respect to a particular source, the nomination will be deemed to be the nomination for the previous day unless a standing nomination is in effect. Any gas takes outside such previous nominated volumes treated in accordance with Article X and the other provisions of this Agreement.~~

~~Nominations for delivery of gas on the first day of any month will be provided to the Company twenty-four (24) hours before the interstate pipeline nominations are due for the next month. The nomination shall be transmitted to EnergyNorth Natural Gas, Inc., Gas Supply Department, Fax No. (603) 623-4644 Attention: Gas Dispatch Supervisor, and such nominations shall not be deemed made until received.~~

~~This nomination provides Company with notice of Customer's expected transportation requirements and does not alter any other provisions of this agreement. It is Customer's responsibility to ensure that volumes delivered by the Transportation Pipeline to the Customer's Receipt Point(s) conform with the terms of this agreement.~~

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~~B. Customer shall be solely responsible for securing faithful performance by the Transportation Pipeline and/or its suppliers in all matters which may affect Company's performance hereunder, and Company shall not be liable hereunder to Customer or to any other person as a result of the failure of the Transportation Pipeline or Customer's suppliers to so perform.~~ (D)

~~C. When any of Customer's sources of gas are also sources of gas for other transportation customers of Company and they have a common agent, at a given interstate pipeline meter, agent shall provide a common daily nomination covering all customers delivering gas from such source. Customer hereby appoints the party identified in Exhibit A or a subsequently designated agent pursuant to the Agency Agreement as its agent for the purposes of making such nominations and determining the proper allocation of volumes among all affected customers. In the event all nominated volumes are not delivered and in the absence of an agent designation, allocation methods by the Company will be pro rata as among such customers.~~

~~ARTICLE VI.~~

~~TERM~~

~~The term of this agreement shall commence on its effective date as provided in Article I, above, and shall continue until the following July 31. This agreement shall further continue thereafter for successive one year periods ending July 31 of each subsequent year, subject to the right of Company or Customer to terminate this agreement by written notice delivered to the other at least sixty (60) days prior to the end of the respective one year period.~~

~~This service is also available in conjunction with the equivalent sales service. The customer may elect to enter into concurrent interruptible sales and transportation contracts. Should the customer elect to do so, the customer must also elect on a monthly basis which service is to be utilized. In any event, the customer is only responsible for the payment of one service charge per month.~~

~~ARTICLE VII.~~

~~MEASUREMENT OF TRANSPORTATION VOLUMES~~

~~A. The volumes of gas delivered hereunder to Customer shall be determined by use of measuring equipment which the Company owns and operates. Any additional metering equipment required to provide service hereunder shall be selected, installed and maintained by Company, including but not limited to remote-controlled telephone and metering equipment (Remote Metering) required to allow Company to instantaneously monitor Customer's usage.~~

~~B. In the event any meter fails to register, or registers incorrectly, Company shall reasonably determine the length of the period for which such meter failed to register or registered incorrectly and, based upon Company records of Customer usage indicating the prior gas usage of its equipment and other information, and the quantity of gas delivered during such period, the Company will make an appropriate adjustment based thereon. For the purpose of this section, any meter which registers not more than two (2) percent higher or lower than actual shall be deemed correct.~~

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~~In addition, Customer shall furnish and maintain, at no cost to Company, the necessary space, housing, fencing, and foundations for the meters, regulators, and other gas equipment owned by Company and installed upon Customer's premises, whether such equipment is furnished by Customer or Company. Such space, housing, fencing, and foundations shall be in conformity with public laws and regulations, and subject to Company's specifications and approval.~~ (D)

~~C. Meter readings for normal billing purposes will be taken, if practicable, daily at approximately 10:00 a.m. through the Remote Metering referred to in Section A of this Article. Remote Metering will be designed to monitor and record the Customer's maximum consumption during any given twenty-four hour time period. If Remote Metering is utilized, Company shall make an on-site meter reading each month at Customer's Facility to verify the Remote Metering. If there is any inconsistency between an on-site meter reading and the Remote Metering, Company shall make reasonable adjustments in the latter type of readings to make them consistent with the on-site readings.~~

~~D. Company, at its expense, shall periodically inspect and test its meters and shall replace its meters at intervals not exceeding the period designated for replacement by the New Hampshire General Laws, as amended or superseded from time to time. At the written request of Customer, Company shall make additional tests of any such meters in the presence of Customer's representatives. The cost of such additional tests shall be borne by Customer whenever the error is found not to be greater than two (2) percent.~~

~~E. Customer shall furnish, own, maintain, and operate at its expense the complete system of such piping and appurtenance on Customer's side of the Delivery Point as are sufficient for the proper utilization of the gas to be transported hereunder.~~

~~F. Customer shall provide Company such reasonable rights of way on and rights of entry to Customer's Facility as may be required by Company in connection with this agreement, including without limitation, access for any removal, use, maintenance and periodic inspection of all Company's pipe and metering.~~

~~ARTICLE VIII.~~

~~PRESSURE AND QUALITY~~

~~A. The natural gas to be transported hereunder shall be received by Company from the Transportation Pipeline at the Receipt Point and shall be delivered to Customer at the Delivery Point.~~

~~B. Deliveries of gas by or on behalf of Customer to Company shall be made against the distribution pipeline pressure existing in Company's distribution system. Company will not be obligated to alter such distribution pipeline pressure. Company shall deliver natural gas hereunder to Customer at the Customer's Delivery Point at the Company's system pressure.~~

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~~C. The natural gas delivered hereunder by the Transportation Pipeline to Company shall be of at least the same quality as that specified in the Transportation Pipeline's Federal Energy Regulatory Commission Gas Tariff governing deliveries by the Transportation Pipeline to Company. The gas delivered hereunder by Company to Customer shall be of similar quality as that delivered generally to the Company's firm customers. It is understood by Customer that Company, from time to time, may supplement its system supply with other alternative sources of gas, including, without limitation, vaporized liquefied natural gas and propane gas.~~ (D)

~~ARTICLE IX.~~

~~RATES AND BILLING~~

~~A. Rates. Any transportation services used by the Customer pursuant to this agreement shall be charged to Customer pursuant to the tariffed rate, attached hereto as Exhibit B and the terms of this agreement.~~

~~B. Billing.~~

~~1. Customer shall pay its bills monthly. Any amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed, are subject to a late payment charge of one and one half percent (1 1/2%) per month on the unpaid balance.~~

~~2. If the Transportation Pipeline invoice is reissued and adjusts the quantity of transportation gas delivered to Company for the account of Customer, a corresponding adjustment shall be made in the next bill rendered to Customer after receipt of such invoice by Company, or as soon as practicable.~~

~~3. In addition to other payments provided for herein, Customer shall pay to Company the amount of any governmental assessment or tax on the transportation of gas, in effect at the time service is provided, which Company may hereafter be required to pay or collect by any federal, state or local law.~~

~~ARTICLE X.~~

~~BALANCING SERVICE AND CHARGES~~

~~A. Customer Responsibility~~

~~It is the responsibility of the Customer to control and, if necessary, adjust receipts of gas by the Company at the Receipt Point(s) to be in balance with deliveries of such gas by the Company to the Delivery Point(s). The Company shall not be obligated to receive or deliver gas in excess of the Daily Scheduled Quantity by the Customer, nor shall the Company be obligated to deliver to the Customer at the Delivery Point quantities of gas in excess of the quantities received for Customer at the Receipt Point(s). The Customer is responsible for keeping informed as to its Daily Metered Quantity, and for making appropriate~~

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~~adjustments to its consumption of gas to ensure that the Imbalance is kept as near to zero as practicable. The Company will monitor, to the best of its ability, actual receipts and deliveries under this Agreement and shall have this information available upon customer request four (4) hours after completion of each Gas Day during normal business hours.~~ (D)

~~Any adjustment to scheduled receipts and deliveries by Customer, whether or not pursuant to notification from Customer's Transportation Pipeline, shall be coordinated with the Company and shall be in accordance with the Company's scheduling procedures. In order to balance quantities received and delivered by the Company pursuant to this Agreement, Company shall not be obligated to accept quantities of gas for the account of Customer or deliver gas to Customer at points other than as originally scheduled by Customer and accepted by Company pursuant to this Agreement.~~

~~B. Daily Imbalance Requirements and Charges~~

~~The Customer shall manage gas usage and gas supplies so as to limit any Daily Overtake or Undertake to the Company's Swing Tolerance Level, usually 10% of the Daily Scheduled Quantity. There shall be a daily Imbalance charge of $.04836 per therm for Overtake or Undertake Quantities that exceed the Swing Tolerance Level percentage of the Daily Scheduled quantity. On any given Gas Day in the month, should the Company be in an Imbalance situation greater than the current daily Imbalance percentage with its Transportation Pipeline, the Company shall assign these Imbalance charges assessed to the Company by upstream pipelines to the two groups of customers that the Company provides service to, i.e. sales and transportation customers, based on the extent that each group caused such charges. The portion of any such charges assigned to sales customers shall be included in an appropriate deferred gas cost account. The portion of any such charges assigned to transportation customers shall be further assigned to individual transportation customers based on the extent to which each transportation customer caused such charges. The charges, if any, assigned to each transportation customer, shall be included along with the appropriate documentation in the Customer's monthly bill.~~

~~Any quantities of gas taken under non-curtailment conditions over the MDQ shall be considered unauthorized use and paid for at the charge of One Dollar and Fifty Cents ($1.50) per therm and these quantities shall not be subject to the Monthly Imbalance Charges at Paragraph E.~~

~~C. Imbalance Trading~~

~~Customers shall be allowed to enter into agreements to trade offsetting daily Imbalances that occur on the same Gas Day, subject to the provisions of this Agreement. Customers entering into such agreements, however, shall remain responsible both separately and severally for any remaining Imbalance charges or overrun charges resulting from the parties' transportation activity occurring on such Gas Day. The parties to such agreement shall notify the Company of the proposed agreement within forty-eight (48) hours of the end of the Gas Day on which the Imbalances occurred by completion of the Transportation Nomination Form attached to this agreement as Exhibit B2. Customers are required to use this Nomination Form for all Imbalance trades. The Company has the right to extend the trading period and/or reject any proposed trade arrangements for operational considerations. By approving the proposed trade arrangement, the Company assumes no~~

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~~responsibilities for enforcing any of the terms of the arrangement between the parties to any such agreement. Nothing herein shall prohibit the Company from trading Imbalances with its transportation customers.~~

(D)

~~D. Monthly Imbalance Charges~~

~~Unless the Company and Customer agree to correct Imbalances in kind on a non-discriminatory basis, the end of month Imbalance, if less than or equal to 5%, will be cashed out at the Company's cashout price, and monthly Imbalances, to the extent they exceed 5%, will be cashed out at the Company's cashout price plus an additional percentage for customer overtakes and at the cashout price minus an additional percentage for customer undertakes. See Schedules A and B.~~

~~The Company's cashout price referenced in the following Schedules A and B shall be calculated as follows: When supplemental supplies are not being dispatched and when a Customer's monthly Imbalance is an Undertake and the Company purchases the Imbalance gas from the Customer, the cashout price shall be the Tennessee cashout price (market area, appropriate month) increased to reflect TGP fuel retention from zone 0 to zone 6 (FT-A fuel = 8.71% winter and 7.42% summer) plus the pipeline commodity (volumetric) charges for the effective TGP FT-A rate schedule including base rates plus all associated surcharges.~~

~~Example A:~~

| | | |
|---|---|---|
| ~~TGP Cashout~~ | ~~=~~ | ~~$2.20~~ |
| ~~Fuel Retention~~ | ~~=~~ | ~~8.71% (winter)~~ |
| ~~Eff. TGP Cashout~~ | ~~=~~ | ~~$2.4099~~ |
| ~~FT-A 0-6 Commodity~~ | ~~=~~ | ~~$0.1608 Base Rate (TGP Tariff)~~ |
| | ~~=~~ | ~~$0.0022 ACA (FERC approved surcharge)~~ |
| | ~~=~~ | ~~$0.0075 GRI (FERC approved surcharge)~~ |
| | ~~=~~ | ~~$0.0000 Other Surcharge~~ |
| ~~Total ENGI Cashout~~ | ~~=~~ | ~~$2.5804per Dth/10 = $0.2580per therm~~ |

~~When supplemental supplies are not being dispatched, and when a customer's monthly Imbalance is an Overtake and the Company sells the imbalance gas to the customer, the cashout price shall be the Tennessee cashout price (market area, appropriate month) increased to reflect TGP fuel retention from zone 0 to zone 6 (FT-A/IT fuel = 8.71% winter and 7.42% summer) plus the average pipeline commodity (volumetric) charges for the effective TGP FT-A and IT rate schedules including base rates plus all associated surcharges.~~

~~Example B:~~

| | | |
|---|---|---|
| ~~TGP Cashout~~ | ~~=~~ | ~~$2.20~~ |
| ~~Fuel Retention~~ | ~~=~~ | ~~8.71% (winter)~~ |
| ~~Eff. TGP Cashout~~ | ~~=~~ | ~~$2.4099~~ |
| ~~FT-A 0-6 Commodity~~ | ~~=~~ | ~~$0.1608 Base Rate (TGP Tariff)~~ |
| ~~IT 0-6 Commodity~~ | ~~=~~ | ~~$0.7647 Base Rate (TGP Tariff)~~ |
| ~~FT-A/IT Average~~ | ~~=~~ | ~~$0.4628 Base Rate~~ |
| | ~~=~~ | ~~$0.0022 ACA (FERC approved surcharge)~~ |
| | ~~=~~ | ~~$0.0075 GRI (FERC approved surcharge)~~ |
| | ~~=~~ | ~~$0.0000 Other Surcharge~~ |
| ~~Total ENGI Cashout~~ | ~~=~~ | ~~$2.8727 per Dth/10 = $0.2873 per therm~~ |

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~~Schedule A~~

| ~~Percent Monthly Imbalance~~ | ~~Company charges percentage of Cashout Price~~ |
|---|---|
| ~~First five percent (0 - 5 %)~~ | ~~100%~~ |
| ~~Next five percent (> 5 - 10%)~~ | ~~115%~~ |
| ~~Next five percent (> 10 - 15%)~~ | ~~130%~~ |
| ~~Next five percent (> 15 - 20%)~~ | ~~140%~~ |
| ~~Over twenty percent (> 20%)~~ | ~~150%~~ |

(D)

~~Schedule B~~

| ~~Percent Monthly Imbalance~~ | ~~Company charges percentage of Cashout Price~~ |
|---|---|
| ~~First five percent (0 - 5 %)~~ | ~~100%~~ |
| ~~Next five percent (> 5 - 10%)~~ | ~~85%~~ |
| ~~Next five percent (> 10 - 15%)~~ | ~~70%~~ |
| ~~Next five percent (> 15 - 20%)~~ | ~~60%~~ |
| ~~Over twenty percent (> 20%)~~ | ~~50%~~ |

~~E. Limitations of Balancing Service~~

~~If the Company determines, at its sole discretion, that a transportation customer is intentionally acting so as to financially gain from the provisions for Monthly or Daily Imbalance Charges or Monthly Imbalance Credits as provided for in the Company's Transportation Agreement, the Company shall, upon such a determination, first provide an Initial Notification of Balancing Limitations by telephone or telephone facsimile. The Initial Notification shall include a description of corrective actions that the customer must take, and shall have a deadline of not less than twenty-four (24) hours for initiating the corrective actions. If the transportation customer does not satisfy the requirements set forth in the Initial Notification, the Company shall issue a Second Notification of Balancing Limitations. Starting with the first gas day after the issuance of the Second Notification, any Daily Imbalance Charge as provided for in Article X, B, of this Agreement, shall be increased by a Balancing Surcharge of $0.10 per therm. In addition, for that month, the Monthly Imbalance Charges provided for in Article X, E, Schedules A, B and C of the Company's tariffs shall be increased by a Balancing Surcharge of $0.10 per therm and the Monthly Imbalance Credits provided for in Article X, E, Schedules D, E and F shall be decreased by a Balancing Surcharge of $0.10 per therm. The Balancing Surcharge shall remain in effect until the longer of: (1) three gas days, or (2) one gas day after the transportation customer satisfies the provisions of the Initial Notification of Balancing Limitations. The Company may charge the Balancing Surcharge of $0.10 per therm starting the next gas day after issuing a Notification of Balancing Limitations - Repeat Offender to any customer that has been issued an Initial Notification according to the provisions of this section one (1) time previously in the last thirty (30) days or two (2) times previously in the last ninety (90) days. The Balancing Surcharge shall remain in effect until the longer of: (1) three gas days, or (2) one gas day after the transportation customer satisfies the provisions of the Notification of Balancing Limitations - Repeat Offender.~~

~~The Company's determination as to restrictions on Balancing Services pursuant to this section shall be appealable to the Commission.~~

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~~ARTICLE XI~~ (D)

~~FORCE MAJEURE~~

~~A. If either the Company or the Customer is rendered unable by force majeure to wholly or in part carry out its obligations under the provisions of this Agreement, the obligations of the party affected by such force majeure, other than the obligation to make payments thereunder, shall be suspended during the continuance of any inability so caused but for no longer period; and such cause shall, insofar as possible, be remedied with all reasonable dispatch.~~

~~B. The term "force majeure" as employed herein, shall mean acts and events not within the control of the party claiming suspension and shall include acts of God, strikes, lockouts, material or equipment or labor shortages, wars, riots, insurrections, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of rulers and peoples, interruptions by government or court orders, present or future orders of any regulatory body having proper jurisdiction, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or pipelines, and any other cause whether of the kind herein enumerated or otherwise, not within the control of the party claiming suspension and which, by the exercise of reasonable foresight, such party if unable to avoid and, by the exercise of due diligence, such party is unable to overcome.~~

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~~ARTICLE XII.~~

~~DEFAULT~~

(D)

~~If either party shall fail to perform or otherwise be in default of any of its obligations under this agreement (Event of Default), the other party may terminate this agreement by giving the defaulting party written notice stating specifically the nature of the default and giving notice of termination. Any termination of this agreement shall be without prejudice to the right of the Company to collect any payments due Company for transportation service~~
~~prior to the time of termination including interest and any properly applied charges for imbalance. Company is entitled to costs or attorneys' fees incurred in pursuing collection of any monies owed Company by Customer. No waiver by either party of any Event of Default of the other under this agreement shall operate as a waiver of any future Event of Default, whether of like or different character or nature.~~

~~ARTICLE XIII~~

~~MISCELLANEOUS~~

~~A. Customer shall be deemed to be in exclusive control and possession of transportation gas until such gas has been delivered to Company by Transportation Pipeline. Company shall be deemed to be in control and possession of gas delivered to it by the Transportation Pipeline for Customer in accordance with this agreement until such gas has been delivered to Customer at the Delivery Point, after which Customer shall be deemed to be in control and possession thereof. Customer shall have no responsibility, except as otherwise provided by agreement, with respect to the gas from the Receipt Point until it passes the Delivery Point.~~

~~B. Neither Company nor the Customer shall be liable to the other, or party claiming through the other, for special or consequential damages, and each agrees to hold the other harmless against such claims.~~

~~C. Customer warrants that it will, at the time of delivery to Company of gas from the Transportation Pipeline, have good and merchantable title to all gas so delivered to Company. Customer indemnifies Company and holds it harmless from all suits, actions, debts, accounts, damages, costs, losses and expense arising out of the adverse claims of any ant persons to said gas and/or to royalties, taxes, licenses, or charges thereon with which are applicable to such gas and/or the delivery of such gas to Company transportation hereunder. Title to the gas received, transported and delivered at all times shall remain with Customer and shall not pass to Company.~~

~~D. Customer shall provide Company with information sufficient for the Company to transport gas and shall notify Company in writing of any modification to such information, occurring or made effective after the execution of this agreement. Any such modification of information shall not obligate Company to modify this agreement in accordance therewith, but Company retains the right to do so.~~

~~E. Company is a public utility subject to regulation by New Hampshire Public Utilities Commission. This agreement must be filed with the Commission accordance with New Hampshire General Laws and shall, subject to any disapproval or limitation imposed by the Commission, become effective on the thirty-first day after the date of such filing or on such later date as may be~~

~~ordered by Commission. Compliance by Company with any order of the Commission or any other federal, state or local government authority acting under claim of jurisdiction issued before or after the effective date of this agreement, shall not be deemed to be a breach hereof. The provisions in this agreement shall be subject to review and determination by the Commission in any proceeding brought under provisions of the New Hampshire General Laws. In the event of the issuance of an order of the Commission under the New Hampshire General laws, which modifies the provisions of this contract, either Company or Customer, if affected adversely by such order, shall have the option within thirty(30) days after the issuance of such order to terminate this agreement by giving notice of termination to the other party.~~ (D)

~~F. All notices required or permitted to be given hereunder shall be deemed given upon mailing such notices by registered or certified mail, postage prepaid, addressed as follows:~~

~~If to Customer:~~ ______________________
______________________
______________________
______________________

~~If to Company:~~ ~~EnergyNorth Natural Gas, Inc.~~
~~201 Rivermoor Street~~
~~West Roxbury, MA 02132~~
~~Attention: Director, Customer Choice and Energy Supply~~

~~IN WITNESS WHEREOF, the parties hereto have caused this agreement to be duly executed by their authorized officers as of the date first written above.~~

~~For Customer~~

~~By:~~ ______________________
~~Title:~~ ______________________

~~Date:~~ ____________ ~~Witness:~~ ______________________

~~EnergyNorth Natural Gas, Inc.~~
~~D/b/a KeySpan Energy Delivery New England~~
~~By:~~ ______________________
~~Title:~~ ______________________

~~Date:~~ ____________ ~~Witness:~~ ______________________

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~~**Exhibit A**~~

~~Revised 5/13/99~~

~~**ENERGYNORTH NATURAL GAS, INC.**~~
~~**TRANSPORTATION CONTRACT ELECTION FORM**~~ (D)

~~**EnergyNorth Natural Gas, Inc.**~~
~~Gas Supply Department~~
~~201 Rivermoor Street~~
~~West Roxbury, MA 02132~~
~~**Tel. #: (617) 723-5512**~~
~~**Fax #: (617) 363-9715**~~

~~**Effective Date:**~~ ______

~~**Customer Information**~~

~~Company (Account) Name:~~ ____________________

~~Facility Address:~~ ____________________

~~Pipeline City Gate (Receipt Point) Meter No.:~~ ____________________

~~Premise (Account) Number:~~ ____________ ~~Meter No.:~~ ____________

~~Company Representative:~~ ____________________

~~Telephone No.:~~ ____________________

~~Fax No.:~~ ____________________

~~Authorized Agent (Marketing Company): Refer to the Agency Authorization Agreement~~

~~Authorized Agent (Marketing Representative): Refer to the Agency Authorization Agreement~~

~~Authorized Agent (Telephone No.): Refer to the Agency Authorization Agreement~~

~~**Contract Service Elections**~~

~~Maximum Daily Quantity (MDQ):~~ ____________ ~~Therms~~

~~Customer Authorization:~~ ____________________

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~~Revised 5/13/99~~ ~~Exhibit B1~~

~~**PIPELINE TRANSPORTATION NOMINATION FORM**~~

~~EnergyNorth Natural Gas, Inc.~~ (D)

~~Gas Supply Department~~

~~201 Rivermoor Street~~

~~West Roxbury, MA 02132~~

~~Tel. #: (617) 723-5512~~ ~~Fax #: (617) 363-9715~~

~~Contacts: Dawn Querzoli, Customer Choice Analyst Ext. 4743~~

~~Katy Barrett, Manager Customer Choice Ext. 4734~~

~~Liz Danehy, Director Customer Choice Ext. 4730~~

~~**Customer Information:**~~

~~Company Name:~~ ______

~~Facility Address:~~ ______

~~Contact Name:~~ ______

~~Telephone #:~~ ______ ~~Fax #:~~ ______

~~Account #:~~ ______ ~~Customer Meter No.:~~ ______

~~**EnergyNorth Transportation Information:**~~

~~Start Date: ___/___/___ 10:00 am (Eastern Time)~~

~~Note: This nomination will roll over from one day to the next through the last day of each month unless customer submits a new nomination. If weekend load is different than weekday load, note it in the appropriate space below and we will adjust weekend nomination confirmations with Tennessee Gas Pipeline accordingly. Also, let EnergyNorth know if nomination changes are needed for holidays.. Imbalance trading adjustments can be made to bring monthly imbalances back in line.~~

~~Agent/Supplier:~~ ______ ~~Tel. #:~~ ______

~~Daily Transportation Volume Request (Therms):~~

| ~~**Monday**~~ | ~~**Tuesday**~~ | ~~**Wednesday**~~ | ~~**Thursday**~~ | ~~**Friday**~~ | ~~**Saturday**~~ | ~~**Sunday**~~ | ~~**Other**~~ |
|---|---|---|---|---|---|---|---|
| ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ |
| ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ |
| ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ |
| ~~Therms~~ | ~~Therms~~ | ~~Therms~~ | ~~Therms~~ | ~~Therms~~ | ~~Therms~~ | ~~Therms~~ | ~~Therms~~ |

~~**Tennessee Gas Pipeline Information /** Daily gas volume nominations to EnergyNorth gate stations:~~

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ | ~~A~~ ____ |
| ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ | ~~B~~ ____ |
| ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ | ~~C~~ ____ |

| ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ |
|---|---|---|---|---|---|---|---|

| | |
|---|---|
| ~~**Downstream Service Package Number:**~~ | ~~**Tennessee Meter Number (Gate Station) Reference:**~~ |
| ~~(Tennessee transportation contract #)~~ | |
| ~~A~~ | ~~Nashua 020132 Hooksett 020254~~ |
| ~~B~~ | ~~Londonderry 020632 Suncook 020451~~ |
| ~~C~~ | ~~Manchester 020133 Laconia/Concord 020426~~ |
| | |
| ~~Therm to MMBtu Conversion Example:~~ | |
| ~~Goal: To receive 400 Therms at your facility~~ | |
| ~~Desired Therms MMBtu Conversion Factor~~ | ~~Required MMBtu~~ |
| ~~Procedure 400 Therms / 10~~ | ~~= 40 MMBtu~~ |
| | |
| ~~Note to Firm Transportation Customers: At the end of the month the total volume of metered gas will be multiplied by 1.022 for system loss allowance.~~ | |
| ~~Signature:~~ | |

**(PROVISIONS DELETED**
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~~Revised 8/28/01~~ ~~Exhibit B2~~

~~Imbalance Trading/Standby Service~~
~~TRANSPORTATION NOMINATION FORM~~

~~EnergyNorth Natural Gas, Inc.~~
~~Gas Supply Department~~
~~201 Rivermoor Street~~
~~West Roxbury, MA 02132~~
~~Tel. #: (617) 723-5512 Fax #: (617) 363-9715~~

(D)

| | | |
|---|---|---|
| ~~Contacts:~~ | ~~Dawn Querzoli, Customer Choice Analyst~~ | ~~Ext. 4743~~ |
| | ~~Katy Barrett, Manager Customer Choice~~ | ~~Ext. 4734~~ |
| | ~~Liz Danehy, Director Customer Choice~~ | ~~Ext. 4730~~ |

~~Customer Information~~

~~These nominations will not roll over from one day to the next. Standby Service nominations are purchases of supply from EnergyNorth to a specific customer. Imbalance Trading nominations are two-part nominations requiring a source of supply and a corresponding destination for the same volume (therms).~~

| | | | | |
|---|---|---|---|---|
| ~~Effective Date:~~ ____ / ____ / ____ ~~MM DD YY~~ | ~~Check Appropriate Box~~ ~~Type of Nomination:~~ | ~~Imbalance Trade~~ | | |

| ~~Supply Source and Volume~~ | ~~Supply Destination and Volume~~ |
|---|---|
| ~~#1~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#2~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#3~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#4~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#5~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#6~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#7~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#8~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#9~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |

~~Signature:~~ ________________________________

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(D)

~~***ENERGYNORTH NATURAL GAS, INC.***~~
~~***d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND***~~

~~***INTERRUPTIBLE TRANSPORTATION***~~

~~***SERVICE AGREEMENT***~~

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~~**ENERGYNORTH NATURAL GAS, INC.**~~

~~**INTERRUPTIBLE TRANSPORTATION SERVICE AGREEMENT**~~

(D)

~~ARTICLE I.~~

~~PREAMBLE~~

~~This agreement is made this _____ day of __________, ____ by and between EnergyNorth Natural Gas, Inc., d/b/a KeySpan Energy Delivery New England, a New Hampshire corporation with its principal place of business at 1260 Elm Street, Manchester, New Hampshire 03105 (Company), and ______________________ a ____________________ corporation with its principal place of business at _______________________________________________________ (Customer).~~

~~Service under this agreement will commence (as defined by EnergyNorth Natural Gas, Inc.) on the _____ day of ______________, __________ and shall be referred to as the effective date of service.~~

~~WITNESSETH:~~

~~WHEREAS, Customer owns or has access to volumes of natural gas which can be delivered through the Tennessee Gas pipeline system (Transportation Pipeline) which it desires to have transported to its facility located at ______________________________________________________ (Customer's Facility); and~~

~~WHEREAS, Company is willing to receive, transport and deliver such gas to Customer at Customer's facility;~~

~~NOW THEREFORE, in consideration of the mutual covenants and agreements contained herein, and subject to the laws and regulations of the State of New Hampshire, the parties do covenant and agree as follows:~~

~~ARTICLE II.~~

~~GOVERNING LAW~~

~~This agreement shall be subject to the General Laws of the State of New Hampshire and the Terms and Conditions as authorized from time to time by the New Hampshire Public Utilities Commission (the Commission), to the extent such terms and conditions apply to the transportation of natural gas or other terms and conditions of service. In the event of a conflict between said Terms and Conditions applicable to transportation services and the provisions of this agreement, this agreement shall govern. This agreement shall be further subject to any Commission order affecting transportation service.~~

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## ~~ARTICLE III.~~

## ~~DEFINITIONS~~

~~**Daily Metered Quantity** - The actual quantity of gas used by the Customer during the Gas Day as measured by the Company's metering equipment at the Delivery Point.~~ (D)

~~**Daily Overtake Quantity** - An Imbalance in which the difference between the Daily Metered Quantity and the Daily Scheduled Quantity is a positive number, i.e., where Daily Metered Quantity exceeds the Daily Scheduled Quantity.~~

~~**Daily Scheduled Quantity** - The quantity of gas scheduled to be received during the Gas Day by the Company at the Receipt Point for the account of Customer, for redelivery at the Delivery Point during the same Gas Day.~~

~~**Daily Undertake Quantity** - An Imbalance in which the difference between the Daily Metered Quantity net of the Daily Scheduled Quantity is a negative number, i.e., where Daily Metered Quantity is less than the Daily Scheduled Quantity.~~

~~**Delivery Point** - A location where the Company's distribution facilities are interconnected with the Customer's facility and where the Customer's gas will be delivered by the Company.~~

~~**Gas Day** - A period of twenty-four (24) consecutive hours beginning at 10:00 a.m. E.T., and ending at 10:00 a.m., the next calendar day.~~

~~**Imbalance** - The difference, during the Gas Day, between the Daily Scheduled Quantity and Daily Metered Quantity.~~

~~**Marginal Cost** - The variable cost of the Company's marginal source of gas, including variable Transportation Pipeline charges, for the Gas Day.~~

~~**Maximum Daily Quantity (MDQ)** - The maximum gas quantity which Customer has a right to use and the Company is obligated to deliver during any Gas Day. The quantity shall be no greater than the Customer's hourly connected load times twenty-four (24) hours.~~

~~**Receipt Point** - An interconnection between the Customer's Transporting Pipeline and the distribution facilities of the Company where gas will be received by the Company for transportation in its service territory.~~

~~**Swing Tolerance Level** - The daily Imbalance allowance between the Daily Scheduled Quantity and the Daily Metered Quantity at the Delivery Point. The default level will be ± 10%, but can be adjusted by the Company only if Tennessee Gas Pipeline (TGP) imposes tighter tolerance levels (i.e., TGP may issue an Operational Flow Order (OFO) restricting the Company to a tighter swing tolerance level). Notice will be given to customers before any changes are made to the Swing Tolerance Level as defined in Article X, Paragraph G.~~

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~~**Transportation Pipeline** - The person(s), Company(ies) or other party(ies), engaged in the business of rendering transportation service of natural gas in interstate commerce, subject to the jurisdiction of the Federal Energy Regulatory Commission, which the person(s), Company(ies) or party(ies) is (are) transporting gas for Customer's account to the Receipt Point of the distribution facilities of the Company.~~ (D)

## ~~ARTICLE IV.~~

## ~~SERVICE TO BE PROVIDED BY COMPANY~~

~~A. Company will receive from Customer, at the Receipt Point(s) designated in Exhibit A, volumes of natural gas up to a Maximum Daily Quantity (MDQ) as defined in Exhibit A of this agreement , subject to its rights under Article IV, Paragraph (C), hereunder. Company will use its best efforts to transport this MDQ of natural gas to Customer at Customer's Facility.~~

~~B. Transportation service will be provided on a best efforts basis and will be subject to interruption and/or curtailment to the extent the Company determines in its sole judgment such interruption to be necessary to ensure continued service to the Company's firm sales and firm transportation customers. All curtailments or interruptions by Company will be made in accordance with Article XI and the Company's Supply and Capacity Shortage Allocation Policy.~~

~~C. Company will give Customer at least two hours advance notice by telephone of any such curtailment or interruption at Customer's telephone number(s) as defined in Exhibit A and Customer shall be available to receive such notice twenty four (24) hours a day, seven (7) days a week. Upon receipt of such notice, Customer shall curtail or discontinue the use of gas from the delivery point within two hours. In the event of a major system failure, Customer agrees to discontinue gas use as soon as possible after notification from Company. In the event of any failure to curtail or discontinue gas use, Customer will pay Company an additional charge of One Dollar and Fifty Cents ($1.50) per therm for all unauthorized gas use after the conclusion of the two hour notification period. Notwithstanding any payment of such additional charge, Company may discontinue transportation service to Customer if Customer fails to comply with its obligations to discontinue use in accordance with the provisions of this contract, which failure by Customer shall constitute an Event of Default as defined in Article XII.~~

~~D. Insofar as practicable, Customer shall arrange for transportation quantities at a uniform rate throughout the day.~~

~~E. The Receipt Point(s) at the Company's city gate set forth in Exhibit A may be changed only by mutual agreement. Customer shall include any proposed changes in the Company's city gate Receipt Point(s) with its nomination submitted for service on the first day of a given month. Company reserves the right to reject such proposed changes.~~

~~F It is understood that Company has no obligation to provide service under this agreement other than on the interruptible basis described above. Customer warrants and agrees that it shall maintain complete alternate standby fuel and equipment available for use in the event of curtailment or interruption of service. Customer agrees that Company has the right to inspect such equipment, but not an obligation to inspect nor to ensure that such standby equipment is adequate for Customer's requirements.~~

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~~Notwithstanding the foregoing, Company shall not be liable to Customer or to Customer's customers for any loss or damage incurred by Customer resulting from (a) any curtailment or interruption, including a permanent interruption in the delivery of the transportation volume, whether or not notice of such curtailment or interruption is given, or (b) any variation in the quality or pressure of the transportation volume delivered.~~ (D)

~~G. Nothing herein shall be construed as obligating Company to construct additional facilities. If new or additional facilities, other than remote metering costs, are required on the Company's system for Customer to receive interruptible transportation service, Customer shall prepay for the facilities.~~

~~If Customer converts to this service from another service classification without satisfying payment of facilities costs in the Company's Service and Main Extension tariff, the costs of facilities unrecovered by the company must be prepaid by the customer.~~

~~H. The Company's As Available Gas Supply Service is available in conjunction with this Interruptible Transportation Service.~~

~~I. In the event the Company, during a curtailment or interruption, requires emergency gas, and takes the gas of Customer, Customer shall be compensated for such emergency gas at the Customer's alternate cost of fuel as demonstrated to the reasonable satisfaction of the Company.~~

~~ARTICLE V.~~

~~CUSTOMER RESPONSIBILITIES~~

~~A. Customer shall provide Company with a written nomination, with information sufficient for the Company to confirm nominations, substantially identical to Exhibit B1, stating the maximum volume to be transported by Company during the next day. Such nominations must be received on or before 8:00 a.m. of each Gas Day, unless a standing nomination for each Gas Day has been received twenty-four (24) hours before the interstate pipeline nominations are due for the month, in order to be effective for the next day, provided, however, that earlier nominations may be required. Company will notify Customer if an earlier nomination deadline is required by another transporter. If no nomination is made by Customer with respect to a particular source, the nomination will be deemed to be the nomination for the previous day unless a standing nomination is in effect. Any gas takes outside such previous nominated volumes will be treated in accordance with Article X and the other provisions of this Agreement.~~

~~Nominations for delivery of gas on the first day of any month will be provided to the Company twenty-four (24) hours before the interstate pipeline nominations are due for the next month. The nomination shall be transmitted to EnergyNorth Natural Gas, Inc., Gas Supply Department Fax No. (603) 623-4644, Attention: Gas Dispatch Supervisor, and such nominations shall not be deemed made until received.~~

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~~This nomination provides Company with notice of Customer's expected transportation requirements and does not alter any other provisions of this agreement. It is Customer's responsibility to ensure that volumes delivered by the Transportation Pipeline to the Customer's Receipt Point(s) conform with the terms of this agreement.~~ (D)

~~B. Customer shall be solely responsible for securing faithful performance by the Transportation Pipeline and/or its suppliers in all matters which may affect Company's performance hereunder, and Company shall not be liable hereunder to Customer or to any other person as a result of the failure of the Transportation Pipeline or Customer's suppliers to so perform.~~

~~C. When any of Customer's sources of gas are also sources of gas for other transportation customers of Company and they have a common agent, at a given interstate pipeline meter, agent shall provide a common daily nomination covering all customers delivering gas from such source. Customer hereby appoints the party identified in Exhibit A or a subsequently designated agent pursuant to the Agency Agreement as its agent for the purposes of making such nominations and determining the proper allocation of volumes among all affected customers. In the event all nominated volumes are not delivered and in the absence of an agent designation, allocation methods by the Company will be pro rata as among such customers.~~

~~ARTICLE VI.~~

~~TERM~~

~~The term of this agreement shall commence on its effective date as provided in Article I, above, and shall continue until the following July 31. This agreement shall further continue thereafter for successive one year periods ending July 31 of each subsequent year, subject to the right of Company or Customer to terminate this agreement by written notice delivered to the other at least sixty (60) days prior to the end of the respective one year period.~~

~~ARTICLE VII.~~

~~MEASUREMENT OF TRANSPORTATION VOLUMES~~

~~A. The volumes of gas delivered hereunder to Customer shall be determined by use of measuring equipment which the Company owns and operates. Any additional metering equipment required to provide service hereunder shall be selected, installed and maintained by Company, including but not limited to remote-controlled telephone and metering equipment (Remote Metering) required to allow Company to instantaneously monitor Customer's usage.~~

~~B. In the event any meter fails to register, or registers incorrectly, Company shall reasonably determine the length of the period for which such meter failed to register or registered incorrectly and, based upon Company records of Customer usage indicating the prior gas usage of its equipment and other information, and the quantity of gas delivered during such period, the Company will make an appropriate adjustment based thereon. For the purpose of this section, any meter which registers not more than two (2) percent higher or lower than actual shall be~~

~~deemed correct.~~

**PROVISIONS DELETED**
**RESERVED FOR FUTURE USE**

~~In addition, Customer shall furnish and maintain, at no cost to Company, the necessary space, housing, fencing, and foundations for the meters, regulators, and other gas equipment owned by Company and installed upon Customer's premises, whether such equipment is furnished by Customer or Company. Such space, housing, fencing, and foundations shall be in conformity with public laws and regulations, and subject to Company's specifications and approval.~~ (D)

~~C. Meter readings for normal billing purposes will be taken, if practicable, daily at approximately 10:00 a.m. through the Remote Metering referred to in Section A of this Article. Remote Metering will be designed to monitor and record the Customer's maximum consumption during any given twenty-four hour time period. If Remote Metering is utilized, Company shall make an on-site meter reading each month at Customer's Facility to verify the Remote Metering. If there is any inconsistency between an on-site meter reading and the Remote Metering, Company shall make reasonable adjustments in the latter type of readings to make them consistent with the on-site readings.~~

~~D. Company, at its expense, shall periodically inspect and test its meters and shall replace its meters at intervals not exceeding the period designated for replacement by the New Hampshire General Laws, as amended or superseded from time to time. At the written request of Customer, Company shall make additional tests of any such meters in the presence of Customer's representatives. The cost of such additional tests shall be borne by Customer whenever the error is found not to be greater than two (2) percent.~~

~~E. Customer shall furnish, own, maintain, and operate at its expense the complete system of such piping and appurtenance on Customer's side of the Delivery Point as are sufficient for the proper utilization of the gas to be transported hereunder.~~

~~F. Customer shall provide Company such reasonable rights of way on and rights of entry to Customer's Facility as may be required by Company in connection with this agreement, including without limitation, access for any removal, use, maintenance and periodic inspection of all Company's pipe and metering.~~

## ~~ARTICLE VIII.~~

## ~~PRESSURE AND QUALITY~~

~~A. The natural gas to be transported hereunder shall be received by Company from the Transportation Pipeline at the Receipt Point and shall be delivered to Customer at the Delivery Point.~~

~~B. Deliveries of gas by or on behalf of Customer to Company shall be made against the distribution pipeline pressure existing in Company's distribution system. Company will not be obligated to alter such distribution pipeline pressure. Company shall deliver natural gas hereunder to Customer at the Customer's Delivery Point at the Company's system pressure.~~

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~~C. The natural gas delivered hereunder by the Transportation Pipeline to Company shall be of at least the same quality as that specified in the Transportation Pipeline's Federal Energy Regulatory Commission Gas Tariff governing deliveries by the Transportation Pipeline to Company. The gas delivered hereunder by Company to Customer shall be of similar quality as that delivered generally to the Company's firm customers. It is understood by Customer that Company, from time to time, may supplement its system supply with other alternative sources of gas, including, without limitation, vaporized liquefied natural gas and propane gas.~~ (D)

~~ARTICLE IX.~~

~~RATES AND BILLING~~

~~A. Rates. Any transportation services used by the Customer pursuant to this agreement shall be charged to Customer pursuant to the tariffed rate, attached hereto as Exhibit B and the terms of this agreement.~~

~~B. Billing.~~

~~1. Customer shall pay its bills monthly. Any amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed, are subject to a late payment charge of one and one half percent (1 1/2%) per month on the unpaid balance.~~

~~2. If the Transportation Pipeline invoice is reissued and adjusts the quantity of transportation gas delivered to Company for the account of Customer, a corresponding adjustment shall be made in the next bill rendered to Customer after receipt of such invoice by Company, or as soon as practicable.~~

~~3. In addition to other payments provided for herein, Customer shall pay to Company the amount of any governmental assessment or tax on the transportation of gas, in effect at the time service is provided, which Company may hereafter be required to pay or collect by any federal, state or local law.~~

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~~ARTICLE X.~~

~~BALANCING SERVICE AND CHARGES~~

(D)

~~A. Customer Responsibility~~

~~It is the responsibility of the Customer to control and, if necessary, adjust receipts of gas by the Company at the Receipt Point(s) to be in balance with deliveries of such gas by the Company to the Delivery Point(s). The Company shall not be obligated to receive or deliver gas in excess of the Daily Scheduled Quantity by the Customer, nor shall the Company be obligated to deliver to the Customer at the Delivery Point quantities of gas in excess of the quantities received for Customer at the Receipt Point(s). The Customer is responsible for keeping informed as to its Daily Metered Quantity, and for making appropriate adjustments to its consumption of gas to ensure that the Imbalance is kept as near to zero as practicable. The Company will monitor, to the best of its ability, actual receipts and deliveries under this Agreement and shall have this information available upon customer request four (4) hours after completion of each Gas Day during normal business hours.~~

~~Any adjustment to scheduled receipts and deliveries by Customer, whether or not pursuant to notification from Customer's Transportation Pipeline, shall be coordinated with the Company and shall be in accordance with the Company's scheduling procedures. In order to balance quantities received and delivered by the Company pursuant to this Agreement, Company shall not be obligated to accept quantities of gas for the account of Customer or deliver gas to Customer at points other than as originally scheduled by Customer and accepted by Company pursuant to this Agreement.~~

**PROVISIONS DELETED**
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~~B. Daily Imbalance Requirements and Charges~~

~~The Customer shall manage gas usage and gas supplies so as to limit any Daily Overtake or Undertake to the Company's Swing Tolerance Level, usually 10% of the Daily Scheduled Quantity, unless there is timely notice of a different level consistent with TGP tolerances. The Company agrees to give Customer as much notice as possible but not less than eight hours before the requirement to change the tolerance level, or notice shall be pursuant to Article X, Paragraph G, Operational Flow Orders. There shall be a daily Imbalance charge of $.04836 per therm for Overtake or Undertake Quantities that exceed the Swing Tolerance Level percentage of the Daily Scheduled quantity. On any given Gas Day in the month, should the Company be in an Imbalance situation greater than the current daily Imbalance percentage with its Transportation Pipeline, the Company shall assign these Imbalance charges assessed to the Company by upstream pipelines to the two groups of customers that the Company provides service to, i.e. sales and transportation customers, based on the extent that each group caused such charges. The portion of any such charges assigned to sales customers shall be included in an appropriate deferred gas cost account. The portion of any such charges assigned to transportation customers shall be further assigned to individual transportation customers based on the extent to which each transportation customer caused such charges. The charges, if any, assigned to each transportation customer, shall be included along with the appropriate documentation in the Customer's monthly bill.~~ (D)

~~Any quantities of gas taken under non-curtailment conditions over the MDQ shall be considered unauthorized use and paid for at the charge of One Dollar and Fifty Cents ($1.50) per therm and these quantities shall not be subject to the Monthly Imbalance Charges at Paragraph E.~~

~~C. Imbalance Trading~~

~~Customers shall be allowed to enter into agreements to trade offsetting daily Imbalances that occur on the same Gas Day, subject to the provisions of this Agreement. Customers entering into such agreements, however, shall remain responsible both separately and severally for any remaining Imbalance charges or overrun charges resulting from the parties' transportation activity occurring on such Gas Day. The parties to such agreement shall notify the Company of the proposed agreement within forty-eight (48) hours of the end of the Gas Day on which the Imbalances occurred by completion of the Transportation Nomination Form attached to this agreement as Exhibit B. Customers are required to use this Nomination Form for all Imbalance trades. The Company has the right to extend the trading period and/or reject any proposed trade arrangements for operational considerations. By approving the proposed trade arrangement, the Company assumes no responsibilities for enforcing any of the terms of the arrangement between the parties to any such agreement. Nothing herein shall prohibit the Company from trading Imbalances with its transportation customers.~~

~~D. Monthly Imbalance Charges~~

~~Unless the Company and Customer agree to correct Imbalances in kind on a non-discriminatory basis, the end of month Imbalance, if less than or equal to 5%, will be cashed out at the Company's cashout price, and monthly Imbalances, to the extent they exceed 5%, will be cashed out at the Company's cashout price plus an additional percentage for customer overtakes and at the cashout price minus an additional percentage for customer undertakes. See Schedules A and B.~~

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~~The Company's cashout price referenced in the following Schedules A and B shall be calculated as follows: When supplemental supplies are not being dispatched and when a Customer's monthly Imbalance is an undertake and the Company purchases the imbalance gas from the Customer, the cashout price shall be the Tennessee cashout price (market area, appropriate month) increased to reflect TGP fuel retention from zone 0 to zone 6 (FT-A fuel = 8.71% winter and 7.42% summer) plus the pipeline commodity (volumetric) charges for the effective TGP FT-A rate schedule including base rates plus all associated surcharges.~~ (D)

~~Example A:~~

| | | |
|---|---|---|
| ~~TGP Cashout~~ | ~~=~~ | ~~$2.20~~ |
| ~~Fuel Retention~~ | ~~=~~ | ~~8.71% (winter)~~ |
| ~~Eff. TGP Cashout~~ | ~~=~~ | ~~$2.4099~~ |
| ~~FT-A 0-6 Commodity~~ | ~~=~~ | ~~$ Base Rate~~ |
| | ~~=~~ | ~~$0.0022 ACA (FERC approved surcharge)~~ |
| | ~~=~~ | ~~$0.0075 GRI (FERC approved surcharge)~~ |
| | ~~=~~ | ~~$0.0000 Other surcharge~~ |
| ~~Total ENGI Cashout~~ | ~~=~~ | ~~$2.5804 per Dth/10 = $0.2580 per therm~~ |

~~When supplemental supplies are not being dispatched, and when a customer's monthly Imbalance is an Overtake and the Company sells the imbalance gas to the customer, the cashout price shall be the Tennessee cashout price (market area, appropriate month) increased to reflect TGP fuel retention from zone 0 to zone 6 (FT-A/IT fuel = 8.71% winter and 7.42% summer) plus the average pipeline commodity (volumetric) charges for the effective TGP FT-A and IT rate schedules including base rates plus all associated surcharges.~~

~~Example B:~~

| | | |
|---|---|---|
| ~~TGP Cashout~~ | ~~=~~ | ~~$2.20~~ |
| ~~Fuel Retention~~ | ~~=~~ | ~~8.71% (winter)~~ |
| ~~Eff. TGP Cashout~~ | ~~=~~ | ~~$2.4099~~ |
| ~~FT-A 0-6 Commodity~~ | ~~=~~ | ~~$1608 Base Rate~~ |
| ~~IT 0-6 Commodity~~ | ~~=~~ | ~~$0.7647 Base Rate (TGP Tariff)~~ |
| ~~FT-A/IT Average~~ | ~~=~~ | ~~$0.4648 Base Rate (TGP Tariff)~~ |
| | ~~=~~ | ~~$0.0022 ACA (FERC approved surcharge)~~ |
| | ~~=~~ | ~~$0.0085 GRI (FERC approved surcharge)~~ |
| | ~~=~~ | ~~$0.000 Other surcharge~~ |
| ~~Total ENGI Cashout~~ | ~~=~~ | ~~$2.8727 per Dth/10 = $0.28727 per therm~~ |

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~~Schedule A~~

| ~~Percent Monthly Imbalance~~ | ~~Company charges percentage of Cashout Price~~ | |
|---|---|---|
| ~~First five percent (0 - 5 %)~~ | ~~100%~~ | (D) |
| ~~Next five percent (> 5 - 10%)~~ | ~~115%~~ | |
| ~~Next five percent (> 10 - 15%)~~ | ~~130%~~ | |
| ~~Next five percent (> 15 - 20%)~~ | ~~140%~~ | |
| ~~Over twenty percent (> 20%)~~ | ~~150%~~ | |

~~Schedule B~~

| ~~Percent Monthly Imbalance~~ | ~~Company charges percentage of Cashout Price~~ |
|---|---|
| ~~First five percent (0 - 5 %)~~ | ~~100%~~ |
| ~~Next five percent (> 5 - 10%)~~ | ~~85%~~ |
| ~~Next five percent (> 10 - 15%)~~ | ~~70%~~ |
| ~~Next five percent (> 15 - 20%)~~ | ~~60%~~ |
| ~~Over twenty percent (> 20%)~~ | ~~50%~~ |

~~E. Limitations of Balancing Service~~

~~If the Company determines, at its sole discretion, that a transportation customer is intentionally acting so as to financially gain from the provisions for Monthly or Daily Imbalance Charges or Monthly Imbalance Credits as provided for in the Company's Transportation Agreement, the Company shall, upon such a determination, first provide an Initial Notification of Balancing Limitations by telephone or telephone facsimile. The Initial Notification shall include a description of corrective actions that the customer must take, and shall have a deadline of not less than twenty-four (24) hours for initiating the corrective actions. If the transportation customer does not satisfy the requirements set forth in the Initial Notification, the Company shall issue a Second Notification of Balancing Limitations. Starting with the first gas day after the issuance of the Second Notification, any Daily Imbalance Charge as provided for in Article X, B, of this Agreement, shall be increased by a Balancing Surcharge of $0.10 per therm. In addition, for that month, the Monthly Imbalance Charges provided for in Article X, E, Schedule B of the Company's tariffs shall be increased by a Balancing Surcharge of $0.10 per therm and the Monthly Imbalance Credits provided for in Article X, E, Schedule B shall be decreased by a Balancing Surcharge of $0.10 per therm. The Balancing Surcharge shall remain in effect until the longer of: (1) three gas days, or (2) one gas day after the transportation customer satisfies the provisions of the Initial Notification of Balancing Limitations. The Company may charge the Balancing Surcharge of $0.10 per therm starting the next gas day after issuing a Notification of Balancing Limitations - Repeat Offender to any customer that has been issued an Initial Notification according to the provisions of this section one (1) time previously in the last thirty (30) days or two (2) times previously in the last ninety (90) days. The Balancing Surcharge shall remain in effect until the longer of: (1) three gas days, or (2) one gas day after the transportation customer satisfies the provisions of the Notification of Balancing Limitations - Repeat Offender.~~

~~The Company's determination as to restrictions on Balancing Services pursuant to this section shall be appealable to the Commission.~~

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~~F. Operational Flow Order~~

~~The Company shall have the right to issue an Operational Flow Order(s) (OFO) to its Customers if an OFO has been issued by its Transportation Pipeline which may limit the amount of service available and may contain more restrictive balancing provisions, among other things. OFO's shall be issued via telephone to be followed by a facsimile. The OFO will set forth (a) the time and date of issuance; (b) the actions Customer is required to take; (c) the time by which Customer must be in compliance with the OFO; (d) the anticipated duration of the OFO; and (e) any other terms which the Company may reasonably require to ensure the effectiveness of the OFO. If the Company cannot contact the Customer due to the Customer's failure to have a person available, such Customer shall be solely responsible for any consequences, including but not limited to equipment breakdown, lost production, freezing of pipes, etc., which could have been prevented by such communication. During an OFO, the daily Imbalance charge at Schedule B may be adjusted to reflect the Imbalance charges assessed by the Company's Transportation Pipeline. During an OFO, the Customer shall nominate on a daily basis the expected Daily Metered Quantity and will not be allowed to use any prior Imbalance that may have accumulated prior to the OFO.~~ (D)

~~ARTICLE XI~~

~~FORCE MAJEURE~~

~~A. If either the Company or the Customer is rendered unable by force majeure to wholly or in part carry out its obligations under the provisions of this Agreement, the obligations of the party affected by such force majeure, other than the obligation to make payments thereunder, shall be suspended during the continuance of any inability so caused but for no longer period; and such cause shall, insofar as possible, be remedied with all reasonable dispatch.~~

~~B. The term "force majeure" as employed herein, shall mean acts and events not within the control of the party claiming suspension and shall include acts of God, strikes, lockouts, material or equipment or labor shortages, wars, riots, insurrections, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of rulers and peoples, interruptions by government or court orders, present or future orders of any regulatory body having proper jurisdiction, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or pipelines, and any other cause whether of the kind herein enumerated or otherwise, not within the control of the party claiming suspension and which, by the exercise of reasonable foresight, such party if unable to avoid and, by the exercise of due diligence, such party is unable to overcome.~~

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~~ARTICLE XII.~~

~~DEFAULT~~

~~If either party shall fail to perform or otherwise be in default of any of its obligations under this agreement (Event of Default), the other party may terminate this agreement by giving the defaulting party written notice stating specifically the nature of the default and giving notice of termination. Any termination of this agreement shall be without prejudice to the right of the Company to collect any payments due Company for transportation service prior to the time of termination including interest and any properly applied charges for imbalance. Company is entitled to costs or attorneys' fees incurred in pursuing collection of any monies owed Company by Customer. No waiver by either party of any Event of Default of the other under this agreement shall operate as a waiver of any future Event of Default, whether of like or different character or nature.~~ (D)

~~ARTICLE XIII~~

~~MISCELLANEOUS~~

~~A. Customer shall be deemed to be in exclusive control and possession of transportation gas until such gas has been delivered to Company by Transportation Pipeline. Company shall be deemed to be in control and possession of gas delivered to it by the Transportation Pipeline for Customer in accordance with this agreement until such gas has been delivered to Customer at the Delivery Point, after which Customer shall be deemed to be in control and possession thereof. Customer shall have no responsibility, except as otherwise provided by agreement, with respect to the gas from the Receipt Point until it passes the Delivery Point.~~

~~B. Neither Company nor the Customer shall be liable to the other, or party claiming through the other, for special or consequential damages, and each agrees to hold the other harmless against such claims.~~

~~C. Customer warrants that it will, at the time of delivery to Company of gas from the Transportation Pipeline, have good and merchantable title to all gas so delivered to Company. Customer indemnifies Company and holds it harmless from all suits, actions, debts, accounts, damages, costs, losses and expense arising out of the adverse claims of any ant persons to said gas and/or to royalties, taxes, licenses, or charges thereon with which are applicable to such gas and/or the delivery of such gas to Company transportation hereunder. Title to the gas received, transported and delivered at all times shall remain with Customer and shall not pass to Company.~~

~~D. Customer shall provide Company with information sufficient for the Company to transport gas and shall notify Company in writing of any modification to such information, occurring or made effective after the execution of this agreement. Any such modification of information shall not obligate Company to modify this agreement in accordance therewith, but Company retains the right to do so.~~

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~~E. Company is a public utility subject to regulation by New Hampshire Public Utilities Commission. This agreement must be filed with the Commission accordance with New Hampshire General Laws and shall, subject to any disapproval or limitation imposed by the Commission, become effective on the thirty-first day after the date of such filing or on such later date as may be ordered by Commission. Compliance by Company with any order of the Commission or any other federal, state or local government authority acting under claim of jurisdiction issued before or after the effective date of this agreement, shall not be deemed to be a breach hereof. The provisions in this agreement shall be subject to review and determination by the Commission in any proceeding brought under provisions of the New Hampshire General Laws. In the event of the issuance of an order of the Commission under the New Hampshire General laws, which modifies the provisions of this contract, either Company or Customer, if affected adversely by such order, shall have the option within thirty (30) days after the issuance of such order to terminate this agreement by giving notice of termination to the other party.~~ (D)

~~F. All notices required or permitted to be given hereunder shall be deemed given upon mailing such notices by registered or certified mail, postage prepaid, addressed as follows:~~

~~If to Customer:~~ ______________________________
______________________________
______________________________
______________________________

~~If to Company:~~ ~~EnergyNorth Natural Gas, Inc.~~
~~201 Rivermoor Street~~
~~West Roxbury, MA 02132~~
~~Attention: Director, Customer Choice and Energy Supply~~

~~IN WITNESS WHEREOF, the parties hereto have caused this agreement to be duly executed by their authorized officers as of the date first written above.~~

~~For Customer~~

~~By:~~ ______________________________
~~Title:~~ ______________________________
______________________________

~~Date:~~ _______________ ~~Witness:~~ ______________________________

~~EnergyNorth Natural Gas, Inc.~~
~~d/b/a KeySpan Energy Delivery New England~~

~~By:~~ ______________________________
~~Title:~~ ______________________________
______________________________

~~Date:~~ _______________ ~~Witness:~~ ______________________________

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# ~~Exhibit A~~

~~Revised 5/13/99~~

**~~ENERGYNORTH NATURAL GAS, INC.~~**
**~~TRANSPORTATION CONTRACT ELECTION FORM~~**

(D)

**~~EnergyNorth Natural Gas, Inc.~~**
~~Gas Supply Department~~
~~201 Rivermoor Street~~
~~West Roxbury MA 02132~~
**~~Tel. #: ((617) 723-5512~~**
**~~Fax #: (617) 363-9715~~**

**~~Effective Date: _______~~**

**~~Customer Information~~**

~~Company (Account) Name: _______________________________________~~

~~Facility Address: ________________________________________~~

~~Pipeline City Gate (Receipt Point) Meter No.:________________________~~

~~Premise (Account) Number: _________________ Meter No.: _____________~~

~~Company Representative: ________________________________________~~

~~Telephone No.: ___________________________________~~

~~Fax No.: ______________________________________________~~

~~Authorized Agent (Marketing Company): Refer to the Agency Authorization Agreement~~

~~Authorized Agent (Marketing Representative): Refer to the Agency Authorization Agreement~~

~~Authorized Agent (Telephone No.): Refer to the Agency Authorization Agreement~~

**~~Contract Service Elections~~**

~~Maximum Daily Quantity (MDQ): __________________ Therms~~

~~Customer Authorization: ________________________________________~~

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~~Revised 5/13/99~~ ~~Exhibit B1~~

~~**PIPELINE TRANSPORTATION NOMINATION FORM**~~

~~EnergyNorth Natural Gas, Inc.~~
~~Gas Supply Department~~
~~201 Rivermoor Street~~
~~West Roxbury, MA 02132~~
~~Tel. #: (617)723-5512 Fax #: (617)363-9715~~

(D)

~~Contacts: Dawn Querzoli, Customer Choice Analyst Ext. 4732~~
~~Kathy Barrett, Manager customer Ext. 4734~~
~~Liz Danehy, Director Customer Choice Ext. 4730~~

~~**Customer Information:**~~

~~Company Name:~~ ______________________________

~~Facility Address:~~ ______________________________

~~Contact Name:~~ ______________________________

~~Telephone #:~~ ________________ ~~Fax #:~~ ____________

~~Account #:~~ ________________ ~~Customer Meter No.:~~ ________________

~~**EnergyNorth Transportation Information:**~~

~~Start Date: _____/_____/_____ 10:00 am (Eastern Time)~~

~~Note: This nomination will roll over from one day to the next through the last day of each month unless customer submits a new nomination. If weekend load is different than weekday load, note it in the appropriate space below and we will adjust weekend nomination confirmations with Tennessee Gas Pipeline accordingly. Also, let EnergyNorth know if nomination changes are needed for holidays.~~

~~Agent/Supplier:~~ ________________ ~~Tel. #:~~ ________________

~~Daily Transportation Volume Request (Therms) :~~

| ~~Monday~~ | ~~Tuesday~~ | ~~Wednesday~~ | ~~Thursday~~ | ~~Friday~~ | ~~Saturday~~ | ~~Sunday~~ | ~~Other~~ |
|---|---|---|---|---|---|---|---|
| ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ |
| ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ |
| ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ |
| ~~Therms~~ | ~~Therms~~ | ~~Therms~~ | ~~Therms~~ | ~~Therms~~ | ~~Therms~~ | ~~Therms~~ | ~~Therms~~ |

~~**Tennessee Gas Pipeline Information** / Daily gas volume nominations to EnergyNorth gate stations:~~

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ | ~~A~~ ______ |
| ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ | ~~B~~ ______ |
| ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ | ~~C~~ ______ |
| ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ | ~~MMBtu~~ |

~~**Downstream Service Package Number:**~~ ~~**Tennessee Meter Number (Gate Station) Reference:**~~
~~(Tennessee transportation contract #)~~
~~A~~ ____________ ~~Nashua___020132 Hooksett__020254~~
~~B~~ ____________ ~~Londonderry_______020632 Suncook__020451~~
~~C~~ ____________ ~~Manchester________020133 Laconia/Concord____020426~~

~~Therm to MMBtu Conversion Example:~~

~~Goal: To receive 400 Therms at your facility~~
~~Desired Therms MMBtu Conversion Factor Required MMBtu~~
~~Procedure 400 Therms / 10 = 40 MMBtu~~

~~Note to Firm Transportation Customers: At the end of the month the total volume of metered gas will be multiplied by 1.022 for system loss allowance.~~

~~Signature:~~ ______________________________

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~~Revised 8/28/01~~ ~~Exhibit B2~~

~~**Imbalance Trading/Standby Service**~~
~~**TRANSPORTATION NOMINATION FORM**~~

~~**EnergyNorth Natural Gas, Inc.**~~
~~Gas Supply Department~~
~~201 Rivermoor Street~~
~~West Roxbury, MA 02132~~
~~Tel. #: (617) 723-5512~~ ~~Fax #: (617) 363-9715~~

(D)

~~Contacts: Dawn Querzoli, Customer Choice Analyst Ext. 4743~~
~~Kathy Barrett, Manager Customer Choice Ext. 4734~~
~~Liz Danehy, Director Customer Choice Ext. 4730~~

~~**Customer Information**~~

~~These nominations will not roll over from one day to the next. Standby Service nominations are purchases of supply from EnergyNorth to a specific customer. Imbalance Trading nominations are two-part nominations requiring a source of supply and a corresponding destination for the same volume (therms).~~

| | | | | |
|---|---|---|---|---|
| ~~**Effective Date:**~~ _______ / _______ / _______ ~~MM DD YY~~ | ~~Check Appropriate Box~~ ~~**Type of Nomination:**~~ | ~~Imbalance Trade~~ | | |
| | | | | |

| ~~**Supply Source and Volume**~~ | ~~**Supply Destination and Volume**~~ |
|---|---|
| ~~#1~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#2~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#3~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#4~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#5~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#6~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#7~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#8~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |
| ~~#9~~ ~~Source:~~ ~~Therms:~~ | ~~Destination:~~ ~~Therms:~~ |

~~Signature:~~ ____________________________

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# STATE OF NEW HAMPSHIRE
# BEFORE THE
# PUBLIC UTILITIES COMMISSION



**EnergyNorth Natural Gas, Inc.**
**d/b/a National Grid NH**

**Docket DG 08-009**

**Direct Testimony**
**Of**
**Ann E. Leary**

**February 25, 2008**

## TABLE OF CONTENTS



## ATTACHMENTS

## I. Introduction and Background

**Q. Please state your full name and business address.**

A. My name is Ann E. Leary. My business address is 52 Second Avenue, Waltham, Massachusetts 02451.

**Q. By whom are you employed and in what capacity?**

A. I am employed by KeySpan Corporate Services, LLC as the Manager of Pricing—New England for the National Grid USA regulated local gas distribution companies in Massachusetts and New Hampshire. In that capacity, I provide services to EnergyNorth Natural Gas, Inc., which does business under the name National Grid NH ("National Grid NH" or the "Company").

**Q. Please summarize your professional background with National Grid NH and its affiliates.**

A. In 1985, I joined the Essex County Gas Company as Staff Engineer. In 1987, I became a planning analyst and later became the Manager of Rates. Following the acquisition of Essex by Eastern Enterprises in 1998, I became Manager of Rates for Eastern's regulated gas distribution companies in Massachusetts, which included Boston Gas Company, Essex Gas Company and Colonial Gas Company (acquired by Eastern in 1999), and then subsequently for KeySpan Energy Delivery New England after Eastern was acquired by KeySpan Corporation. Since the November 8, 2000 acquisition of EnergyNorth Natural Gas, Inc. by KeySpan Corporation, I have been responsible for these matters in New Hampshire as well.

**Q. What do your responsibilities as Manager of Pricing—New England include?**

A. As the Manager of Pricing—New England, I am responsible for preparing and submitting various regulatory filings with both the New Hampshire Public Utilities Commission and the Massachusetts Department of Public Utilities on behalf of National Grid's New England gas local distribution companies. This includes Cost of Gas ("COG") filings, Local Distribution Adjustment Charge ("LDAC") filings and reconciliations, energy conservation, performance-based revenue calculations, lost-base revenues, and exogenous cost filings.

**Q. Please summarize your educational background.**

A. I received a Bachelor of Science in Mechanical Engineering from Cornell University in 1983.

**Q. Have you previously testified in regulatory proceedings?**

A. I have testified in numerous gas cost and related proceedings before the New Hampshire Public Utilities Commission over the last several years. Similarly, I have testified in a number of regulatory proceedings before the Massachusetts Department of Public Utilities in rate matters, including providing testimony relating to cost allocation studies, rate design, cost of gas adjustment clause proposals, and exogenous cost filings.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to explain the revenue and billing adjustments to the Company's revenue requirement, summarize the bill impacts resulting from the rate changes being proposed by the Company, and describe certain changes that the Company is proposing be made to the language in its tariff.

## II. Test Year Adjustments

**Q. Please summarize the adjustments you have made to the test period revenues.**

A. Exhibit EN-2-2, page 1, of the Company's filing summarizes the adjustments made to the per-books historical test year revenues. The first column indicates the test year revenues recorded on the Company's books. The second column, "Adjustment", includes a detailed list of all the adjustments made to the historical test year revenues. These adjustments include a weather normalization adjustment (which I will describe later in my testimony), removal of certain revenues including interruptible sales, interruptible transportation, off system sales, and broker balancing charges, and various accounting adjustments such as a correction for revenue from accounts labeled "occupant", removal of the incentive payment for demand side management ("DSM") programs, removal of revenues or costs from financial hedges and removal of the credit from the wet/dry therm billing correction for the period June 2001 - June 2006 relating to Docket DG 06-154. The adjustments also include a proforma adjustment reflecting a proposed increase in the charge for bad checks from $5 to $15. After these adjustments, National Grid NH's total revenue for the test year totals $180,859,301.

**Q. Please explain why interruptible sales, interruptible transportation, off system sales, and broker balancing charges were removed from revenues.**

A. These revenues are flowed back to customers through the cost of gas mechanism, and therefore should not be included in the Company's revenues for purposes of determining the Company's revenue requirement.

**Q. Please describe in further detail the accounting entries which were excluded from revenue.**

A. Prior to 2004, the Company recorded "occupant" bills as revenue. During the test year, if the monthly write offs included a write off associated with an occupant bill, the Company made a manual journal entry to credit the write off by the amount of the occupant bill and simultaneously debit revenue. Since this manual adjustment to revenue reflects bills issued prior to 2004, this amount should be excluded from test year revenue in order to properly reflect revenue related to the test year period. This adjustment is included in the line item labeled "Other" on Exhibit EN-2-2.

The DSM incentive represents an incentive the Company earns based upon meeting certain metrics in its DSM program, and therefore should be treated as a below the line item.

The financial hedges were removed because they too are a below the line item. Each year the Company purchases financial hedges to protect against downswings in seasonal margin resulting from warm weather. These hedges are purchased in order to help stabilize the Company's earnings, something which the Company does at its own risk. Because these transactions are "below the line," they are not properly includable for purposes of determining the Company's revenue requirement. The amount removed from test year revenue relating to these financial hedges was $140,239. (For purposes of clarification, I should note that these hedges are different from the gas cost hedges that the Commission has authorized the Company to purchase, and which are included for purposes of determining cost of gas rates.)

Finally, in DG 06-154, the Company agreed to make a refund to customers to correct for the fact that it had been billing customers on a dry therm basis while its rates had been established on a wet therm basis. During the test year, the Company booked a $2,265,266 reduction to revenues to reflect a credit to customers associated with this overcharge for the period 2001-2007. For purposes of adjusting the test year to reflect only the revenues that relate to the test year itself, the Company has removed the full amount of this credit and then added back $178,379, the portion of the credit relating to throughput during the test year period.

**Q. Please summarize your gas cost adjustment to the test year revenue requirements.**

A. Exhibit EN-2-2-2, page 1, summarizes the adjustments made to the per-books historical test year revenues relating to gas costs. The first column indicates the test year gas costs recorded on the Company's books. The second column, "Adjustment", includes a detailed list of all the adjustments made to the historical test year. These adjustments include a weather normalization adjustment; removal of certain gas costs assigned to interruptible sales, off system sales, and broker balancing charges; and various accounting entries which include occupant gas costs, reallocation of the gas supply portion of bad debt credits and the production and storage credits from the operations and maintenance ("O&M") expense accounts (Accounts 1791 and 1806, respectively) to gas costs. After these adjustments, the Company's gas costs for the test year 2006-07 totaled $133,114,231.

**Q. Please describe in detail why the Company reallocated a portion of the costs related to bad debt and production and storage to gas costs.**

A. In DG 00-063, the Commission unbundled certain costs from the Company's base rates to allow for the recovery of gas-supply related local production and storage, miscellaneous gas costs, and gas cost related bad debt costs through the Cost of Gas ("COG") factor. These costs were previously part of base rates. The amounts to be recovered in the COG were set in DG 00-063 and revised in DG 06-121 and DG 07-050. Each month the Company records its COG revenues by multiplying throughput by the total COG factor, which includes the factor associated with these indirect gas costs. Although these indirect costs are collected through the COG factor, the level of indirect gas costs are established in the test year and, unlike purchased gas costs, they are not reconciled with actual costs each year. Therefore, they should not be part of the COG revenues for revenue requirement purposes. Rather, these costs should be included as base revenues (revenues less gas costs) for purposes of determining the Company's revenue requirement, as they were prior to unbundling. The objective of unbundling was to send the proper price signal to the sales and transportation customers by assigning to their rates the appropriate level of costs for the services they are receiving. The accounting of these costs should not be impacted by the mechanism used to bill the customer (COG versus base rates). The Company credits the operations expense accounts 1791 and 1806 by the amount of these indirect gas cost credits, rather than reducing the COG revenues. Therefore, to establish appropriate base rates, it is necessary to exclude from the test-year O&M expense the effect of the accounting entry. In this pro forma adjustment, the Company is simply reallocating the credits of $3,473,913 from the O&M accounts to the gas cost account. Although this accounting entry will increase the net margin, it will have no impact on the revenue deficiency because there is an offsetting increase in expense.

## III. Billing Adjustments

**Q. Please explain the adjustments that you made to the Company's test year sales volumes and revenues.**

A. Based on prior Commission decisions and consistent with the practice in many other jurisdictions, the Company's rates are established using weather normalized billing determinants, not actual test year volumes. This is because gas utility net revenues are extremely sensitive to weather conditions, and therefore revenue requirement and rate design activities are always structured to allow a reasonable expectation of earnings under the presumption of normal weather conditions. As a result, to establish the Company's revenue requirement, it is first necessary to adjust the actual test year sales volumes and revenues to reflect the level of billing determinants and net (non-gas cost) revenues that could reasonably be expected to have occurred under normal weather conditions.

**Q. What adjustments did you make to the test year sales volumes and net revenues in order to weather normalize them?**

A. First, actual sales volumes and revenues were reviewed to insure that the booked data for sales volumes and revenues were recorded in the months within the test year. Next, any out-of-period revenues that were booked in the test year were removed. These adjustments enable the Company to establish representative sales volumes and revenues by month, season and test year. As part of this process, the out-of-period volumes and revenues associated with the wet/dry therm billing correction that arose from Docket DG 06-154 were removed from the test year data. The reduction in the test year throughput associated with this change was 1,107,694 therms (see Attachment AEL-1, page 5), and the reduction in the net margin was $178,379 (see Attachment AEL-2, page 5).

**Q. Is the Company proposing any other adjustments to its billing determinants?**

A. Yes. The Company is proposing to convert its billing determinants from a wet to a dry basis. The Company is billed by its suppliers on a dry therm basis, and dry therm billing has become the norm in the industry. Continuing to bill customers on a wet therm basis adds to the Company's reporting requirements and increases the potential for billing and reporting errors. For these reasons, the Company is proposing that rates be established on a dry basis, and therefore it is adjusting its billing determinants to state them on a dry therm basis.

**Q. Will there be any revenue impact resulting from this change?**

A. No, as long as the billing determinants used to design the Company's rates are consistent with the units actually billed to customers, there will be no revenue impact to the customer or Company. The billing determinants used in Mr. Goble's rate design attachments are all stated on a dry therm basis.

## IV. Weather Normalization Adjustment

**Q. Was the weather warmer or colder than normal during the test year?**

A. Using the average of the last 30 years of degree day data as measured at the Concord, NH weather station as the standard for normal, the test year was 412 degrees days or 5.7 percent warmer than normal in the Company's service territory.

**Q. Describe the proposed adjustment to sales and revenues to account for the warmer than normal weather experienced during the test year?**

A. My calculations indicate that test year sales were roughly 4.68 million therms less than they would have been if the weather had been normal during the test year, as shown on Attachment AEL-1, page 7. As shown on Attachment AEL-2, page 7, if one assumes increased sales in this amount, the Company's non-gas revenues (or net revenues) would have been $875,798 higher in a normal year compared to actual revenues.

**Q. Have you prepared a schedule to support your weather normalization adjustment?**

A. Yes, the weather normalization calculation is summarized on Attachment AEL-1. These calculations are quite voluminous, so the bulk of the calculations are included in the work papers supporting Attachment AEL-1. The work papers present the weather normalization calculation pertaining to all of the Company's firm weather-sensitive rate classes.

**Q. Please summarize the methodology that the Company uses to weather normalize sales and revenue data.**

A. The normalization technique is the same as that used in the Company's revenue neutral rate case (DG 00-63). The Company determines the weather normalization adjustments to calendar month sales for each rate group with heating loads by identifying the temperature-sensitive portion of sales for each group and calculating how much more or less the monthly sales would have been to that group if weather had been normal. The weather normalizing adjustments to revenues are determined by identifying the average incremental base rate charged to each rate group in each month. This rate is based on the block where the class's average use per meter ends, for the base rate schedule applicable to the rate class. The price of the block in which the average use falls is used as the incremental rate. The product of the incremental rate and the weather normalizing adjustment to sales for each rate group equals the monthly revenue adjustments.

**Q. How did you determine sales and revenues on a calendar month basis to begin the weather normalization calculation?**

A. I followed the method used in the Company's last full rate case, DR 91-212. Each month, the calculation starts with metered system sendout data and subtracts all interruptible sales billed on a calendar month basis and unaccounted for gas to determine total calendar month firm sales. The Company determines the unaccounted for gas by applying the average annual unaccounted for percentage to the total monthly firm (i.e., not including interruptible) sendout. The calendar month firm sales are then allocated to each individual firm rate class based on a rolling two-month average of class sales to total sales. The amount of gas that has been consumed but not yet recorded for billing purposes, known as unbilled sales, is calculated simply as the estimated calendar month sales less the actual billed sales.

**Q. Why didn't you do your weather normalization based on billing month data?**

A. The decision to use calendar month data was based on three factors. First, calendar month data is used because it allows for a matching of the costs incurred and associated revenues for a given month in accordance with accounting principles and allows a more relevant comparison between sales and sendout data. Second, the Company currently bills on a service rendered basis. Third, the calendar month method was utilized in the Company's last base rate case, as approved by the Commission.

**Q. Was the Company able to test the accuracy of this methodology used to convert billing to calendar data?**

A. Yes, the Company currently has monthly bill frequency reports from its billing system which indicate by month and by rate class the actual volumes billed at the Peak and Off Peak head block and tail block rates. By summing the Peak and Off Peak volumes from these monthly reports I was able to determine the Peak and Off Peak volumes for the test year. I then compared these actual Peak and Off Peak volumes (from the bill frequency report) with the Peak and Off Peak volumes calculated using the methodology approved in DR 91-212. (Note that since the Company now bills on a service rendered basis, the billing usage in the months of

November though April no longer corresponds completely to the Peak usage and the billing usage in the months of May through October no longer corresponds completely to the Off Peak usage.) The results of this comparison indicate that according to the reports from the Company's billing system, 74.5% of the annual throughput occurs in the Peak period, whereas the calculation methodology from DR 91-212 indicated that 74.8% of the annual throughput occurs in the Peak period, thus resulting in a variance of only 0.3%.

## V. Test Year Sales and Revenue Proof

**Q. Attachment AEL-2, page 4, indicates that the actual booked margin for the test year is $40,623,185 before corrections for the wet/dry therm billing adjustment and weather normalization adjustment. Have you proven that the actual volumes from Attachment AEL-2, page 4, applied to the current approved base rates will produce this margin?**

A. Yes. Pages 36-50 of the workpaper to Attachments AEL-1 and AEL-2 compares the actual margin stated in the Company's general ledger with the actual margin derived by applying the approved base rates against the actual volumes for the test year. The summary found on page 50 of this backup work paper indicates that the margin from the general ledger differed from the calculated margin by only $43,261, which equates to approximately 0.1 percent.

**Q. Attachment AEL-1, page 14, indicates that the weather normalized test year sales volumes are 150,369,039 therms (on a dry therm basis) and net revenues according to Attachment AEL-2, page 8, are $41,320,604. How**

**have you proven or demonstrated that the weather normalized test year sales volumes applied to the current net base rates produces the weather normalized test year net revenues?**

A. Mr. Goble has performed a revenue proof using bill frequency data to match the normalized sales volumes. In the proof, he multiplied the pro forma billing units by their current rates and developed an independent estimate of the weather normalized test year net revenues. This exercise, summarized on Attachment GLG-RD-4, proves out weather normalized sales and net revenues and assures that the revenue target represents net revenues generated by the current rate.

## VI. <u>Bill Impacts</u>

**Q. Please summarize the bill impacts resulting from the rate changes being proposed by the Company in this case.**

A. The Company anticipates that the average increase for customers in the Residential Heating class will be approximately 6.4% on an annual basis. Residential Non-Heating customers will experience an average 8.5% total bill increase. The Commercial and Industrial High Winter Use customers (G-40 series) will experience bill impacts ranging on average from an increase of 2.8% to an increase of 4.3%, while Commercial and Industrial Low Winter Use customers (G-50 series) will experience bill impacts ranging on average from an increase of 1.0% to an increase of 2.8%. Attachment GLG-RD-4-5 to Mr. Goble's rate design testimony details the various bill impacts by season (Peak and Off Peak) and by usage.

## VII. Proposed Changes to Tariff Provisions

**Q. Please describe the changes the Company is proposing to NHPUC No. 5-Gas KeySpan Energy Delivery New England Section II Rate Schedules.**

A. The Company is proposing to update all its base rate tariffs based on the rate design analysis contained in Mr. Goble's testimony and attachments (see Attachment GLG-RD-4) to reflect the revised customer charges and head block and tail block rates. In addition, the Company is proposing to increase the returned check fee from $5 to $15 to reflect the cost associated with processing a returned check. The Company is also proposing to combine its current G-54 and G-63 customer classes. Currently there is only one customer in rate class G-54. The Company believes it is inappropriate to offer a generally available rate to only one customer. As described in Mr. Goble's testimony, the Company proposes to merge rate G-54 with G-63, so that all of these customers receive service under a rate class that has an availability clause of "load factors greater than 90%." This is currently the availability clause for the G-54 customer class. The availability clause for the G-63 class is "load factors greater than 110%." Since there is only one customer in the current G-54 customer class, the combination of these two classes will have minimum impact on the existing G-63 customers and would provide a 3% savings to the G-54 customer.

**Q. Is the Company proposing any changes to its NHPUC No. 5-Gas KeySpan Energy Delivery New England General Terms and Conditions?**

A. Yes, the Company is proposing changes to its General Terms and Conditions. The Company is proposing the following changes:

1. Bill customers on a dry therm basis instead of a wet therm basis resulting in changes to Section 3 (B) found on page 8.
2. Simplify the Service and Main Extension policy found in Section 7, pages 10 through 13.

**Q. You previously discussed the change from wet therm billing to dry therm billing, but please explain the change that the Company is proposing in its service and main extension policy.**

A. The Company is proposing to significantly simplify the existing policy. The Company's current tariff provides that all customers are entitled to up to an 80-foot service extension at no charge where no main extension is required and where no abnormal costs are involved. In the event of abnormal costs, or a main extension, a case by case determination on each job is required to determine whether and what amount of capital contribution can and will be required pursuant to the so-called 25 percent test. (i.e., the estimated annual margin must be equal to or greater than 25 percent of the estimated construction costs for the main and service extension.) Moreover, the current policy requires that each job for which a contribution is required be revisited 12 months after completion of the work to determine if the actual costs and actual margins result in a calculation of a different required contribution amount. Finally, any time a contribution is required, the Company must revisit the contribution calculation each time a new customer is added to the particular main that was extended to determine if the original customer is entitled to a partial refund.

In many cases, the particular circumstances of a job may not justify the free installation of the initial 80-feet of service line. The Company is proposing a simplified policy that would allow the Company to charge for service line installations regardless of whether a main extension is required. The Company is also proposing to eliminate the 25 percent test and the right of the customer to a future adjustment to the initially agreed upon contribution amount. Instead, each job would be evaluated using an internal rate of return model to determine the level of contribution required to ensure that the investment is not being subsidized by other customers and that it is comparable to other investment opportunities available to the Company.

**Q. Is the Company proposing any changes to its Local Distribution Adjustment Clause, set forth in Section 18 of its tariff?**

A. Yes, the Company is proposing to include a pension and OPEB (post retirement benefits other than pensions) reconciling mechanism in its Local Distribution Adjustment Clause ("LDAC"). As explained in Mr. O'Shaughnessy's testimony, the Company is proposing to reconcile on an annual basis its pensions and OPEB and to include any under or over recovery in its LDAC.

**Q. Is the Company proposing any changes to its 280 day sales service and interruptible sales service?**

A. Yes. The Company is proposing to eliminate these services. There is currently one customer receiving interruptible sales service and no customers receiving 280 Day Sales Service. All customers eligible for this service are able to purchase their commodity service from competitive gas marketers, while obtaining delivery service from the Company. There is no benefit to the Company or its customers to have the Company continue to provide these classes of sales service.

Q. **Is the Company proposing any changes to its Supply and Capacity Shortage Allocation Policy, set forth in Section 19 of its tariff?**

A. Yes, the Company is proposing to update the Penalty section found on page 51. The Company is proposing to revise the penalty that customers pay for all unauthorized volumes of gas taken by a customer from $1.50 per therm to five times the daily index, as defined on page 94 of the tariff. Through the years, the daily index has at times exceeded the $1.50 per therm rate, which would mean that it is actually more advantageous for the customer to pay the penalty instead of purchasing gas.

**Q. Is the Company proposing any changes to its tariff relating to 280 Day Transportation Service and Interruptible Transportation service?**

A. The Company is proposing to eliminate the service agreements for 280 Day and Interruptible Transportation Service (also known as Delivery Service) that are currently set forth as Attachments B and C to the Company's tariff. These agreements largely duplicate the substantive provisions in the tariff that set forth the terms and conditions under which these two classes of service are provided. Having separate agreements that repeat and restate these provisions creates the risk for contradictions between the delivery terms and conditions set forth in the body of the tariff and the language in the agreements. In addition, the forms that are included at the end of the service agreements are now outdated in many ways. The service agreements serve no meaningful purpose, and therefore the Company would like to eliminate their use and rely on the tariff provisions governing these two classes of service.

**Q. Does the Company propose to make other changes to its tariff?**

A. Beginning later this year, the Company plans to adopt the National Grid name in place of the KeySpan name. As a result, all references to KeySpan Energy Delivery in the tariff will be replaced by National Grid NH. When the Company files its compliance filing at the conclusion of this proceeding, it would plan to submit an entirely new tariff, which will be Tariff No. 6, to reflect this change as well as any other changes approved by the Commission in this case.

**Q. Does this conclude your testimony?**

A. Yes it does.

Per Books Data

Customer Count - Actual

| | Number of Bills Customers: | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | 12 Month Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 5,320 | 4,997 | 5,009 | 4,958 | 4,523 | 5,201 | 5,239 | 4,764 | 5,117 | 4,676 | 4,948 | 4,951 | 4,975 |
| 2 | R-3 | 65,408 | 62,270 | 62,904 | 62,087 | 60,191 | 66,866 | 68,052 | 60,887 | 63,563 | 59,757 | 62,073 | 64,591 | 63,221 |
| 3 | R-4 | 4,844 | 4,191 | 4,166 | 3,919 | 1,784 | 3,077 | 4,262 | 4,562 | 6,218 | 6,626 | 6,025 | 4,685 | 4,530 |
| 4 | Total Residential | 75,572 | 71,457 | 72,079 | 70,964 | 66,498 | 75,144 | 77,553 | 70,214 | 74,897 | 71,059 | 73,047 | 74,226 | 72,726 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 7,387 | 7,153 | 7,029 | 7,027 | 6,674 | 7,476 | 7,807 | 7,097 | 7,705 | 7,150 | 7,373 | 7,451 | 7,277 |
| 7 | G-42 | 1,489 | 1,465 | 1,464 | 1,453 | 1,352 | 1,495 | 1,543 | 1,397 | 1,521 | 1,419 | 1,459 | 1,514 | 1,464 |
| 8 | G-43 | 43 | 44 | 40 | 41 | 52 | 45 | 47 | 39 | 43 | 41 | 39 | 37 | 43 |
| 9 | G-51 | 1,392 | 1,368 | 1,322 | 1,337 | 1,240 | 1,404 | 1,447 | 1,300 | 1,422 | 1,293 | 1,369 | 1,379 | 1,356 |
| 10 | G-52 | 311 | 299 | 295 | 300 | 278 | 310 | 323 | 286 | 313 | 281 | 298 | 303 | 300 |
| 11 | G-53 | 38 | 37 | 36 | 42 | 39 | 38 | 39 | 40 | 36 | 38 | 39 | 39 | 38 |
| 12 | G-54 | 2 | 0 | 1 | 1 | 8 | 1 | (6) | 1 | 1 | 1 | 1 | 1 | 1 |
| 13 | G-63 | 14 | 15 | 15 | 15 | 15 | 15 | 23 | 15 | 14 | 15 | 17 | 16 | 16 |
| 14 | Total C/I | 10,676 | 10,381 | 10,202 | 10,215 | 9,657 | 10,784 | 11,223 | 10,176 | 11,055 | 10,239 | 10,595 | 10,740 | 10,495 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 86,247 | 81,838 | 82,281 | 81,180 | 76,156 | 85,929 | 88,775 | 80,390 | 85,952 | 81,299 | 83,642 | 84,966 | 83,221 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 2 | 2 | 2 | 2 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 2 | 1 | 1 |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 86,249 | 81,841 | 82,284 | 81,183 | 76,159 | 85,931 | 88,776 | 80,391 | 85,953 | 81,300 | 83,645 | 84,968 | 83,223 |

**EnergyNorth Natural Gas Inc.**
**Test Year July 2006 - June 2007**
**Development of Billing Determinants**

Adjustments to Per Books Data

Customer Count - Actual

| | | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | 12 Month Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Bills | | | | | | | | | | | | | |
| | Customers: | | | | | | | | | | | | | |
| 1 | R-1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | R-3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | R-4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | Total Residential | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | G-42 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | G-43 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | G-51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | G-52 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | G-53 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | G-54 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | G-63 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total C/I | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Adjusted Billing Determinants

Customer Count - Actual

| | | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | 12 Month Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Bills | | | | | | | | | | | | | |
| | Customers: | | | | | | | | | | | | | |
| 1 | R-1 | 5,320 | 4,997 | 5,009 | 4,958 | 4,523 | 5,201 | 5,239 | 4,764 | 5,117 | 4,676 | 4,948 | 4,951 | 4,975 |
| 2 | R-3 | 65,408 | 62,270 | 62,904 | 62,087 | 60,191 | 66,866 | 68,052 | 60,887 | 63,563 | 59,757 | 62,073 | 64,591 | 63,221 |
| 3 | R-4 | 4,844 | 4,191 | 4,166 | 3,919 | 1,784 | 3,077 | 4,262 | 4,562 | 6,218 | 6,626 | 6,025 | 4,685 | 4,530 |
| 4 | Total Residential | 75,572 | 71,457 | 72,079 | 70,964 | 66,498 | 75,144 | 77,553 | 70,214 | 74,897 | 71,059 | 73,047 | 74,226 | 72,726 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 7,387 | 7,153 | 7,029 | 7,027 | 6,674 | 7,476 | 7,807 | 7,097 | 7,705 | 7,150 | 7,373 | 7,451 | 7,277 |
| 7 | G-42 | 1,489 | 1,465 | 1,464 | 1,453 | 1,352 | 1,495 | 1,543 | 1,397 | 1,521 | 1,419 | 1,459 | 1,514 | 1,464 |
| 8 | G-43 | 43 | 44 | 40 | 41 | 52 | 45 | 47 | 39 | 43 | 41 | 39 | 37 | 43 |
| 9 | G-51 | 1,392 | 1,368 | 1,322 | 1,337 | 1,240 | 1,404 | 1,447 | 1,300 | 1,422 | 1,293 | 1,369 | 1,379 | 1,356 |
| 10 | G-52 | 311 | 299 | 295 | 300 | 278 | 310 | 323 | 286 | 313 | 281 | 298 | 303 | 300 |
| 11 | G-53 | 38 | 37 | 36 | 42 | 39 | 38 | 39 | 40 | 36 | 38 | 39 | 39 | 38 |
| 12 | G-54 | 2 | 0 | 1 | 1 | 8 | 1 | (6) | 1 | 1 | 1 | 1 | 1 | 1 |
| 13 | G-63 | 14 | 15 | 15 | 15 | 15 | 15 | 23 | 15 | 14 | 15 | 17 | 16 | 16 |
| 14 | Total C/I | 10,676 | 10,381 | 10,202 | 10,215 | 9,657 | 10,784 | 11,223 | 10,176 | 11,055 | 10,239 | 10,595 | 10,740 | 10,495 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 86,247 | 81,838 | 82,281 | 81,180 | 76,156 | 85,929 | 88,775 | 80,390 | 85,952 | 81,299 | 83,642 | 84,966 | 83,221 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 2 | 2 | 2 | 2 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 17 |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 2 | 1 | 8 |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 86,249 | 81,841 | 82,284 | 81,183 | 76,159 | 85,931 | 88,776 | 80,391 | 85,953 | 81,300 | 83,645 | 84,968 | 83,246 |

**EnergyNorth Natural Gas Inc**
**Test Year July 2006 - June 2007**
**Development of Billing Determinants**

| | | Per Books Data | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Dry | Dry | Dry | Dry | Dry | Dry | Dry | Wet | Wet | Wet | Wet | Wet | |
| | Actual - Therms billed | Therm | Therm | Therm | Therm | Therm | Therm | Therm | Therm | Therm | Therm | Therm | Therm | |
| | | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
| 1 | R-1 | 66,704 | 53,967 | 60,431 | 69,850 | 83,377 | 112,142 | 127,657 | 142,173 | 142,327 | 109,380 | 91,326 | 71,491 | 1,130,825 |
| 2 | R-3 | 1,268,861 | 1,072,706 | 1,227,943 | 1,883,306 | 3,720,923 | 5,746,761 | 7,668,304 | 10,329,029 | 9,350,562 | 5,787,085 | 3,155,742 | 1,704,992 | 52,916,214 |
| 3 | R-4 | 111,059 | 71,381 | 81,110 | 114,033 | 104,674 | 239,178 | 427,728 | 641,756 | 816,331 | 707,029 | 411,032 | 127,499 | 3,852,810 |
| 4 | Total Residential | 1,446,624 | 1,198,054 | 1,369,484 | 2,067,189 | 3,908,974 | 6,098,081 | 8,223,689 | 11,112,958 | 10,309,220 | 6,603,494 | 3,658,100 | 1,903,982 | 57,899,849 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 279,931 | 133,556 | 274,149 | 461,817 | 1,049,694 | 1,784,455 | 2,692,610 | 3,849,302 | 3,691,716 | 2,120,984 | 1,059,939 | 424,254 | 17,822,387 |
| 7 | G-42 | 626,476 | 531,177 | 689,858 | 1,079,941 | 2,019,702 | 3,029,205 | 4,252,460 | 5,515,644 | 5,542,585 | 3,605,509 | 1,959,393 | 938,454 | 29,790,404 |
| 8 | G-43 | 181,877 | 152,161 | 161,287 | 208,344 | 397,903 | 496,505 | 665,694 | 863,917 | 855,158 | 937,705 | 103,915 | 271,501 | 5,295,967 |
| 9 | G-51 | 207,918 | 201,940 | 193,734 | 232,148 | 264,458 | 343,877 | 430,619 | 550,734 | 539,205 | 384,700 | 293,720 | 238,447 | 3,881,500 |
| 10 | G-52 | 461,181 | 353,312 | 385,907 | 440,019 | 461,410 | 615,746 | 702,968 | 797,921 | 811,051 | 592,570 | 497,977 | 427,243 | 6,547,305 |
| 11 | G-53 | 422,973 | 658,275 | 476,537 | 875,458 | 765,953 | 778,275 | 894,152 | 1,088,956 | 1,027,917 | 944,041 | 817,344 | 690,246 | 9,440,127 |
| 12 | G-54 | 18,737 | 7,117 | 15,313 | 23,665 | 22,993 | 12,563 | 10,340 | 21,206 | 25,336 | 20,714 | 23,852 | 22,032 | 223,868 |
| 13 | G-63 | 1,378,412 | 1,354,004 | 1,401,997 | 1,136,214 | 1,247,745 | 819,796 | 839,164 | 1,100,041 | 500,587 | 713,232 | 1,014,632 | 1,252,742 | 12,758,566 |
| 14 | Total C/I | 3,577,505 | 3,391,542 | 3,598,782 | 4,457,606 | 6,229,858 | 7,880,422 | 10,488,007 | 13,787,721 | 12,993,555 | 9,319,435 | 5,770,772 | 4,264,919 | 85,760,124 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 5,024,129 | 4,589,596 | 4,968,266 | 6,524,795 | 10,138,832 | 13,978,503 | 18,711,696 | 24,900,679 | 23,302,775 | 15,922,929 | 9,428,872 | 6,168,901 | 143,659,973 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 10,950 | 45,095 | 56,109 | 68,029 | 73,205 | 8,794 | - | - | - | 17,383 | 16,585 | 10,543 | 300,693 |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | - | 13,511 | 2,004 | 21,432 | 24,354 | 7,061 | - | - | - | - | 4,781 | 115 | 73,258 |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 5,035,079 | 4,648,202 | 5,026,378 | 6,614,256 | 10,236,391 | 13,994,358 | 18,711,696 | 24,900,679 | 23,302,775 | 15,940,312 | 9,444,238 | 6,179,559 | 144,033,924 |

**EnergyNorth Natural Gas Inc**
**Test Year July 2006 - June 2007**
**Development of Billing Determinants**

Dry/Wet billing Correction

| | | Per Books Data | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
| 1 | R-1 | (1,138) | (923) | (1,045) | (1,211) | (1,429) | (1,952) | (2,233) | | | | | | (9,931) |
| 2 | R-3 | (21,649) | (18,337) | (21,232) | (32,658) | (63,787) | (100,040) | (134,139) | | | | | | (391,844) |
| 3 | R-4 | (1,895) | (1,220) | (1,402) | (1,977) | (1,794) | (4,164) | (7,482) | | | | | | (19,935) |
| 4 | Total Residential | (24,682) | (20,480) | (23,680) | (35,847) | (67,011) | (106,156) | (143,855) | 0 | 0 | 0 | 0 | 0 | (421,710) |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | (4,776) | (2,283) | (4,740) | (8,008) | (17,995) | (31,064) | (47,101) | | | | | | (115,968) |
| 7 | G-42 | (10,689) | (9,080) | (11,928) | (18,727) | (34,623) | (52,733) | (74,387) | | | | | | (212,168) |
| 8 | G-43 | (3,103) | (2,601) | (2,789) | (3,613) | (6,821) | (8,643) | (11,645) | | | | | | (39,215) |
| 9 | G-51 | (3,547) | (3,452) | (3,350) | (4,026) | (4,534) | (5,986) | (7,533) | | | | | | (32,427) |
| 10 | G-52 | (7,868) | (6,040) | (6,673) | (7,630) | (7,910) | (10,719) | (12,297) | | | | | | (59,137) |
| 11 | G-53 | (7,217) | (11,253) | (8,240) | (15,181) | (13,131) | (13,548) | (15,641) | | | | | | (84,210) |
| 12 | G-54 | (320) | (122) | (265) | (410) | (394) | (219) | (181) | | | | | | (1,910) |
| 13 | G-63 | (23,518) | (23,145) | (24,242) | (19,703) | (21,390) | (14,271) | (14,679) | | | | | | (140,949) |
| 14 | Total C/I | (61,038) | (57,975) | (62,227) | (77,300) | (106,798) | (137,163) | (183,464) | 0 | 0 | 0 | 0 | 0 | (685,984) |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | (85,720) | (78,455) | (85,907) | (113,147) | (173,809) | (243,340) | (327,318) | 0 | 0 | 0 | 0 | 0 | (1,107,694) |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | | | | | | | | | | | | | - |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | | | | | | | | | | | | | - |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | | | | | | | | | | | | | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | (85,720) | (78,455) | (85,907) | (113,147) | (173,809) | (243,340) | (327,318) | 0 | 0 | 0 | 0 | 0 | (1,107,694) |

| | | Per Books Data | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Actual - Therms billed | Wet Therm Jul-06 | Wet Therm Aug-06 | Wet Therm Sep-06 | Wet Therm Oct-06 | Wet Therm Nov-06 | Wet Therm Dec-06 | Wet Therm Jan-07 | Wet Therm Feb-07 | Wet Therm Mar-07 | Wet Therm Apr-07 | Wet Therm May-07 | Wet Therm Jun-07 | Total |
| 1 | R-1 | 65,566 | 53,044 | 59,386 | 68,639 | 81,948 | 110,190 | 125,424 | 142,173 | 142,327 | 109,380 | 91,326 | 71,491 | 1,120,894 |
| 2 | R-3 | 1,247,212 | 1,054,369 | 1,206,711 | 1,850,648 | 3,657,136 | 5,646,721 | 7,534,165 | 10,329,029 | 9,350,562 | 5,787,085 | 3,155,742 | 1,704,992 | 52,524,370 |
| 3 | R-4 | 109,164 | 70,161 | 79,708 | 112,056 | 102,880 | 235,014 | 420,246 | 641,756 | 816,331 | 707,029 | 411,032 | 127,499 | 3,832,875 |
| 4 | Total Residential | 1,421,942 | 1,177,574 | 1,345,804 | 2,031,342 | 3,841,963 | 5,991,925 | 8,079,834 | 11,112,958 | 10,309,220 | 6,603,494 | 3,658,100 | 1,903,982 | 57,478,139 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 275,155 | 131,273 | 269,409 | 453,809 | 1,031,699 | 1,753,391 | 2,645,509 | 3,849,302 | 3,691,716 | 2,120,964 | 1,059,939 | 424,254 | 17,706,419 |
| 7 | G-42 | 615,787 | 522,097 | 677,930 | 1,061,214 | 1,985,079 | 2,976,472 | 4,178,073 | 5,515,644 | 5,542,585 | 3,605,509 | 1,959,393 | 938,454 | 29,578,236 |
| 8 | G-43 | 178,774 | 149,560 | 158,498 | 204,731 | 391,082 | 487,862 | 654,049 | 863,917 | 855,158 | 937,705 | 103,915 | 271,501 | 5,256,752 |
| 9 | G-51 | 204,371 | 198,488 | 190,384 | 228,122 | 259,924 | 337,891 | 423,086 | 550,734 | 539,205 | 384,700 | 293,720 | 238,447 | 3,849,073 |
| 10 | G-52 | 453,313 | 347,272 | 379,234 | 432,369 | 453,500 | 605,027 | 690,671 | 797,921 | 811,051 | 592,570 | 497,977 | 427,243 | 6,488,168 |
| 11 | G-53 | 415,756 | 647,022 | 468,297 | 860,277 | 752,822 | 764,727 | 878,511 | 1,088,956 | 1,027,917 | 944,041 | 817,344 | 690,246 | 9,355,917 |
| 12 | G-54 | 18,417 | 6,995 | 15,048 | 23,255 | 22,599 | 12,344 | 10,159 | 21,206 | 25,336 | 20,714 | 23,852 | 22,032 | 221,958 |
| 13 | G-63 | 1,354,894 | 1,330,859 | 1,377,755 | 1,116,511 | 1,226,355 | 805,525 | 824,485 | 1,100,041 | 500,587 | 713,232 | 1,014,632 | 1,252,742 | 12,617,617 |
| 14 | Total C/I | 3,516,467 | 3,333,567 | 3,536,555 | 4,380,306 | 6,123,060 | 7,743,239 | 10,304,543 | 13,787,721 | 12,993,555 | 9,319,435 | 5,770,772 | 4,264,919 | 85,074,140 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 4,938,409 | 4,511,141 | 4,882,359 | 6,411,648 | 9,965,023 | 13,735,163 | 18,384,378 | 24,900,679 | 23,302,775 | 15,922,929 | 9,428,872 | 6,168,901 | 142,552,279 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 10,950 | 45,095 | 56,109 | 68,029 | 73,205 | 8,794 | - | - | - | 17,383 | 10,585 | 10,543 | 300,693 |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | - | 13,511 | 2,004 | 21,432 | 24,354 | 7,061 | - | - | - | - | 4,781 | 115 | 73,258 |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | - | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 4,949,359 | 4,569,747 | 4,940,472 | 6,501,110 | 10,062,583 | 13,751,019 | 18,384,378 | 24,900,679 | 23,302,775 | 15,940,312 | 9,444,238 | 6,179,559 | 142,926,230 |

Adjustments to Per Books Data

Weather Normalization Adjustments to Sales Therms

| | | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | R-3 | 0 | 0 | 20,653 | 85,877 | 806,260 | 1,424,520 | 992,302 | (773,875) | (198,017) | (319,620) | 170,207 | 12,994 | 2,221,301 |
| 3 | R-4 | 0 | 0 | 973 | 2,520 | 29,757 | 69,964 | 57,834 | (57,526) | (20,752) | (41,641) | 19 306 | 1,814 | 62,248 |
| 4 | Total Residential | 0 | 0 | 21,626 | 88,397 | 836,017 | 1,494,484 | 1,050,136 | (831 402) | (218,769) | (361,261) | 189,513 | 14,808 | 2,283,549 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 0 | 0 | 10,033 | 27,622 | 271,993 | 518,690 | 387,447 | (315,595) | (83,089) | (129,160) | 74,274 | 9,136 | 771,351 |
| 7 | G-42 | 0 | 0 | 16,033 | 49,769 | 440,499 | 784,108 | 546,463 | (440,662) | (123,228) | (208,368) | 114,610 | 7,255 | 1,186,478 |
| 8 | G-43 | 0 | 0 | 1,534 | 7,972 | 56,495 | 107,804 | 75,935 | (63,627) | (24 151) | (27,804) | 7,062 | 5,501 | 146,721 |
| 9 | G-51 | 0 | 0 | 446 | 3,961 | 28,813 | 49,542 | 36,618 | (32,246) | (7 670) | (15,898) | 6,275 | 0 | 67,844 |
| 10 | G-52 | 0 | 0 | 982 | 6,181 | 39,748 | 74,547 | 46,164 | (40,752) | (8,947) | (21,372) | 5,615 | 1,563 | 103,728 |
| 11 | G-53 | 0 | 0 | 5,426 | 15,281 | 44,361 | 77,583 | 55,370 | (43,975) | (14 134) | (35,438) | 15,476 | 0 | 119,953 |
| 12 | G-54 | 0 | 0 | 50 | 585 | 0 | 0 | 0 | (753) | (263) | (860) | 968 | 221 | (52) |
| 13 | G-63 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total C/I | 0 | 0 | 34,504 | 111,372 | 879,908 | 1,612,275 | 1,147,996 | (937,610) | (261,481) | (438,901) | 224,282 | 23,677 | 2,396,023 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 0 | 0 | 56,130 | 199,769 | 1,715,925 | 3,106,759 | 2,198,132 | (1,769,011) | (480,250) | (800,162) | 413,795 | 38,485 | 4,679,572 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 0 | 0 | 56,130 | 199,769 | 1,715,925 | 3,106,759 | 2,198,132 | (1,769,011) | (480,250) | (800,162) | 413,795 | 38,485 | 4,679,572 |

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Adjusted Billing Determinants

Weather Normalized Sales

| | | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 65,566 | 53,044 | 59,386 | 68,639 | 81,948 | 110,190 | 125,424 | 142,173 | 142,327 | 109,380 | 91,326 | 71,491 | 1,120,894 |
| 2 | R-3 | 1,247,212 | 1,054,369 | 1,227,363 | 1,936,525 | 4,463,395 | 7,071,241 | 8,526,467 | 9,555,154 | 9,152,545 | 5,467,465 | 3,325,949 | 1,717,986 | 54,745,672 |
| 3 | R-4 | 109,164 | 70,161 | 80,681 | 114,575 | 132,637 | 304,978 | 478,080 | 584,230 | 795,579 | 665,388 | 430,338 | 129,313 | 3,895,123 |
| 4 | Total Residential | 1,421,942 | 1,177,574 | 1,367,430 | 2,119,739 | 4,677,980 | 7,486,409 | 9,129,970 | 10,281,556 | 10,090,451 | 6,242,233 | 3,847,613 | 1,918,790 | 59,761,688 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 275,155 | 131,273 | 279,441 | 481,431 | 1,303,692 | 2,272,081 | 3,032,956 | 3,533,707 | 3,608,627 | 1,991,804 | 1,134,213 | 433,390 | 18,477,770 |
| 7 | G-42 | 615,787 | 522,097 | 693,962 | 1,110,983 | 2,425,577 | 3,760,580 | 4,724,536 | 5,074,982 | 5,419,357 | 3,397,141 | 2,074,003 | 945,709 | 30,764,715 |
| 8 | G-43 | 178,774 | 149,560 | 160,032 | 212,703 | 447,577 | 595,666 | 729,984 | 800,290 | 831,007 | 909,901 | 110,977 | 277,002 | 5,403,472 |
| 9 | G-51 | 204,371 | 198,488 | 190,832 | 232,084 | 286,738 | 387,433 | 459,704 | 518,488 | 531,535 | 368,802 | 299,995 | 238,447 | 3,916,916 |
| 10 | G-52 | 453,313 | 347,272 | 380,216 | 438,569 | 493,248 | 679,574 | 736,835 | 757,169 | 802,104 | 571,198 | 503,592 | 428,806 | 6,591,896 |
| 11 | G-53 | 415,756 | 647,022 | 473,723 | 875,558 | 797,183 | 842,310 | 933,881 | 1,044,981 | 1,013,783 | 908,603 | 832,822 | 690,246 | 9,475,870 |
| 12 | G-54 | 18,417 | 6,995 | 15,098 | 23,840 | 22,599 | 12,344 | 10,159 | 20,453 | 25,073 | 19,854 | 24,820 | 22,253 | 221,906 |
| 13 | G-63 | 1,354,894 | 1,330,859 | 1,377,755 | 1,116,511 | 1,226,355 | 805,525 | 824,485 | 1,100,041 | 500,587 | 713,232 | 1,014,632 | 1,252,742 | 12,617,617 |
| 14 | Total C/I | 3,516,467 | 3,333,567 | 3,571,060 | 4,491,679 | 7,002,969 | 9,355,513 | 11,452,539 | 12,850,111 | 12,732,074 | 8,880,534 | 5,995,054 | 4,288,596 | 87,470,163 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 4,938,409 | 4,511,141 | 4,938,490 | 6,611,417 | 11,680,949 | 16,841,922 | 20,582,510 | 23,131,668 | 22,822,525 | 15,122,767 | 9,842,667 | 6,207,386 | 147,231,852 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 10,950 | 45,095 | 56,109 | 68,029 | 73,205 | 8,794 | 0 | 0 | 0 | 17383 | 10585 | 10543 | 300,693 |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | - | 13,511 | 2,004 | 21,432 | 24,354 | 7,061 | 0 | 0 | 0 | 0 | 4781 | 115 | 73,258 |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 4,949,359 | 4,569,747 | 4,996,602 | 6,700,879 | 11,778,508 | 16,857,777 | 20,582,510 | 23,131,668 | 22,822,525 | 15,140,150 | 9,858,033 | 6,218,044 | 147,605,802 |

EnergyNorth Natural Gas Inc
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Per Books Data

| | Calendar Month Sales - Actual | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 59,186 | 60,055 | 60,204 | 87,879 | 93,408 | 129,126 | 143,866 | 138,928 | 121,746 | 106,882 | 72,559 | 61,083 | 1,134,922 |
| 2 | R-3 | 1,149,619 | 1,207,242 | 1,410,532 | 3,043,835 | 4,473,828 | 7,140,797 | 9,466,628 | 9,594,008 | 7,174,129 | 4,507,284 | 2,084,102 | 1,299,346 | 52,551,350 |
| 3 | R-4 | 89,028 | 80,030 | 88,988 | 129,068 | 157,737 | 347,671 | 558,287 | 714,833 | 745,226 | 568,120 | 219,165 | 105,073 | 3,803,225 |
| 4 | Total Residential | 1,297,833 | 1,347,327 | 1,559,725 | 3,260,782 | 4,724,974 | 7,617,594 | 10,168,781 | 10,447,769 | 8,041,100 | 5,182,286 | 2,375,826 | 1,465,502 | 57,489,497 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 200,517 | 211,582 | 331,598 | 809,251 | 1,329,245 | 2,362,124 | 3,426,604 | 3,679,845 | 2,735,891 | 1,585,749 | 617,949 | 305,813 | 17,596,168 |
| 7 | G-42 | 568,400 | 639,135 | 801,273 | 1,693,230 | 2,391,311 | 3,861,821 | 5,151,836 | 5,400,341 | 4,355,720 | 2,803,558 | 1,227,576 | 680,013 | 29,574,214 |
| 8 | G-43 | 163,961 | 164,729 | 169,525 | 330,442 | 429,867 | 618,421 | 806,707 | 839,309 | 896,776 | 451,373 | 187,690 | 197,042 | 5,255,842 |
| 9 | G-51 | 201,856 | 208,353 | 196,322 | 286,275 | 291,413 | 414,166 | 518,097 | 532,047 | 443,741 | 357,098 | 238,071 | 196,612 | 3,884,053 |
| 10 | G-52 | 399,002 | 386,258 | 382,022 | 524,365 | 514,926 | 709,949 | 799,150 | 785,899 | 675,659 | 581,239 | 416,332 | 395,624 | 6,572,425 |
| 11 | G-53 | 538,110 | 600,865 | 605,734 | 973,643 | 754,480 | 899,961 | 1,050,620 | 1,032,714 | 970,057 | 942,424 | 677,256 | 481,673 | 9,527,536 |
| 12 | G-54 | 12,483 | 11,631 | 17,662 | 27,367 | 18,206 | 12,624 | 16,120 | 22,794 | 22,405 | 24,731 | 20,808 | 17,935 | 224,766 |
| 13 | G-63 | 1,346,066 | 1,449,059 | 1,201,327 | 1,379,790 | 1,044,776 | 900,237 | 1,021,994 | 771,906 | 621,772 | 983,917 | 1,059,600 | 1,172,820 | 12,953,263 |
| 14 | Total C/I | 3,430,395 | 3,673,612 | 3,705,464 | 6,024,363 | 6,774,224 | 9,779,304 | 12,791,128 | 13,064,855 | 10,722,020 | 7,730,089 | 4,445,282 | 3,447,531 | 85,588,265 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 4,728,227 | 5,020,939 | 5,265,188 | 9,285,145 | 11,499,198 | 17,396,897 | 22,959,910 | 23,512,623 | 18,763,121 | 12,912,375 | 6,821,107 | 4,913,033 | 143,077,763 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | - | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 4,728,227 | 5,020,939 | 5,265,188 | 9,285,145 | 11,499,198 | 17,396,897 | 22,959,910 | 23,512,623 | 18,763,121 | 12,912,375 | 6,821,107 | 4,913,033 | 143,077,763 |

Adjustments to Per Books Data

Weather Normalization Adjustments to Calendar Month Sales, therms

| | | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | R-3 | 0 | 0 | 20,653 | 85,877 | 806,260 | 1,424,520 | 992,302 | (773,875) | (198,017) | (319,620) | 170,207 | 12,994 | 2,221,301 |
| 3 | R-4 | 0 | 0 | 973 | 2,520 | 29,757 | 69,964 | 57,834 | (57,526) | (20,752) | (41,641) | 19,306 | 1,814 | 62,248 |
| 4 | Total Residential | 0 | 0 | 21,626 | 88,397 | 836,017 | 1,494,484 | 1,050,136 | (831,402) | (218,769) | (361,261) | 189,513 | 14,808 | 2,283,549 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 0 | 0 | 10,033 | 27,622 | 271,993 | 518,690 | 387,447 | (315,595) | (83,069) | (129,160) | 74,274 | 9,136 | 771,351 |
| 7 | G-42 | 0 | 0 | 16,033 | 49,769 | 440,499 | 784,108 | 546,463 | (440,662) | (123,228) | (208,368) | 114,610 | 7,255 | 1,186,478 |
| 8 | G-43 | 0 | 0 | 1,534 | 7,972 | 56,495 | 107,804 | 75,935 | (63,627) | (24,151) | (27,804) | 7,062 | 5,501 | 146,721 |
| 9 | G-51 | 0 | 0 | 448 | 3,961 | 26,813 | 49,542 | 36,618 | (32,246) | (7,670) | (15,898) | 6,275 | 0 | 67,844 |
| 10 | G-52 | 0 | 0 | 982 | 6,181 | 39,748 | 74,547 | 46,164 | (40,752) | (8,947) | (21,372) | 5,615 | 1,563 | 103,728 |
| 11 | G-53 | 0 | 0 | 5,426 | 15,281 | 44,361 | 77,583 | 55,370 | (43,975) | (14,134) | (35,438) | 15,478 | 0 | 119,953 |
| 12 | G-54 | 0 | 0 | 50 | 585 | 0 | 0 | 0 | (753) | (263) | (860) | 968 | 221 | (52) |
| 13 | G-63 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total C/I | 0 | 0 | 34,504 | 111,372 | 879,908 | 1,612,275 | 1,147,996 | (937,610) | (261,481) | (438,901) | 224,282 | 23,677 | 2,396,023 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 0 | 0 | 56,130 | 199,769 | 1,715,925 | 3,106,758 | 2,198,132 | (1,769,011) | (480,250) | (800,162) | 413,795 | 38,485 | 4,679,572 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 0 | 0 | 56,130 | 199,769 | 1,715,925 | 3,106,758 | 2,198,132 | (1,769,011) | (480,250) | (800,162) | 413,795 | 38,485 | 4,679,572 |

EnergyNorth Natural Gas Inc
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Development of Billing Determinants

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Adjusted Billing Determinants

Weather Normalized Calendar Month Sales- WET

| | | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 59,166 | 60,055 | 60,204 | 87,879 | 93,408 | 129,126 | 143,866 | 138,928 | 121,746 | 106,882 | 72,559 | 61,083 | 1,134,922 |
| 2 | R-3 | 1,149,619 | 1,207,242 | 1,431,185 | 3,129,713 | 5,280,088 | 8,565,317 | 10,458,931 | 8,820,132 | 6,976,112 | 4,187,665 | 2,254,308 | 1,312,340 | 54,772,651 |
| 3 | R-4 | 89,028 | 80,030 | 89,962 | 131,587 | 187,495 | 417,634 | 616,121 | 657,307 | 724,474 | 526,478 | 238,471 | 106,887 | 3,865,474 |
| 4 | Total Residential | 1,297,833 | 1,347,327 | 1,581,350 | 3,349,179 | 5,560,991 | 9,112,077 | 11,218,917 | 9,616,367 | 7,822,332 | 4,821,025 | 2,565,338 | 1,480,310 | 59,773,047 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 200,517 | 211,582 | 341,631 | 836,873 | 1,601,238 | 2,880,814 | 3,814,051 | 3,364,250 | 2,652,802 | 1,456,589 | 692,223 | 314,949 | 18,367,519 |
| 7 | G-42 | 568,400 | 639,135 | 817,305 | 1,742,999 | 2,831,810 | 4,645,929 | 5,698,300 | 4,959,679 | 4,232,492 | 2,595,190 | 1,342,186 | 687,268 | 30,760,693 |
| 8 | G-43 | 163,961 | 164,729 | 171,059 | 338,414 | 486,361 | 726,225 | 882,641 | 775,682 | 872,625 | 423,569 | 194,752 | 202,543 | 5,402,563 |
| 9 | G-51 | 201,856 | 208,353 | 196,770 | 290,237 | 318,226 | 463,708 | 554,715 | 499,801 | 436,071 | 341,200 | 244,346 | 196,612 | 3,951,896 |
| 10 | G-52 | 399,002 | 388,258 | 383,004 | 530,546 | 554,674 | 784,496 | 845,314 | 745,146 | 666,712 | 559,867 | 421,946 | 397,187 | 6,676,153 |
| 11 | G-53 | 538,110 | 600,865 | 611,160 | 988,924 | 798,841 | 977,545 | 1,105,990 | 988,739 | 955,923 | 906,985 | 692,734 | 481,673 | 9,647,489 |
| 12 | G-54 | 12,483 | 11,631 | 17,712 | 27,952 | 18,206 | 12,624 | 16,120 | 22,041 | 22,142 | 23,871 | 21,776 | 18,156 | 224,714 |
| 13 | G-63 | 1,346,066 | 1,449,059 | 1,201,327 | 1,379,790 | 1,044,776 | 900,237 | 1,021,994 | 771,906 | 621,772 | 983,917 | 1,059,600 | 1,172,820 | 12,953,263 |
| 14 | Total C/I | 3,430,395 | 3,673,612 | 3,739,968 | 6,135,735 | 7,654,132 | 11,391,578 | 13,939,124 | 12,127,245 | 10,460,539 | 7,291,188 | 4,669,564 | 3,471,208 | 87,984,288 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 4,728,227 | 5,020,939 | 5,321,318 | 9,484,914 | 13,215,123 | 20,503,656 | 25,158,042 | 21,743,612 | 18,282,871 | 12,112,214 | 7,234,902 | 4,951,518 | 147,757,335 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 4,728,227 | 5,020,939 | 5,321,318 | 9,484,914 | 13,215,123 | 20,503,656 | 25,158,042 | 21,743,612 | 18,282,871 | 12,112,214 | 7,234,902 | 4,951,518 | 147,757,335 |

**EnergyNorth Natural Gas Inc**
**Test Year July 2006 - June 2007**
**Development of Billing Determinants**



Adjusted Billing Determinants

Weather Normalized Calendar Month Sales- DRY THERMS

| | | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Dry Monthly Therm | 1.055 | 1.053 | 1.041 | 1.038 | 1.050 | 1.034 | 1.029 | 1.047 | 1.050 | 1.062 | 1.078 | 1.0650 | |
| | Wet Monthly Therm | 1.037 | 1.035 | 1.023 | 1.020 | 1.032 | 1.016 | 1.011 | 1.029 | 1.032 | 1.043 | 1.059 | 1.0460 | |
| 1 | R-1 | 60,214 | 61,100 | 61,263 | 89,429 | 95,037 | 131,414 | 146,427 | 141,358 | 123,869 | 108,829 | 73,860 | 62,192 | 1,154,994 |
| 2 | R-3 | 1,169,574 | 1,228,237 | 1,456,367 | 3,184,943 | 5,372,183 | 8,717,064 | 10,645,143 | 8,974,420 | 7,097,788 | 4,263,950 | 2,294,754 | 1,336,178 | 55,740,602 |
| 3 | R-4 | 90,573 | 81,422 | 91,544 | 133,910 | 190,765 | 425,033 | 627,090 | 668,805 | 737,111 | 536,069 | 242,750 | 108,829 | 3,933,900 |
| 4 | Total Residential | 1,320,360 | 1,370,758 | 1,609,175 | 3,408,282 | 5,657,985 | 9,273,512 | 11,418,661 | 9,784,584 | 7,958,768 | 4,908,848 | 2,611,364 | 1,507,199 | 60,829,496 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 203,998 | 215,261 | 347,642 | 851,641 | 1,629,166 | 2,931,852 | 3,881,957 | 3,423,100 | 2,699,072 | 1,483,123 | 704,642 | 320,670 | 18,692,125 |
| 7 | G-42 | 576,266 | 650,251 | 831,686 | 1,773,758 | 2,881,202 | 4,728,239 | 5,799,753 | 5,046,437 | 4,306,314 | 2,642,466 | 1,366,267 | 699,752 | 31,304,390 |
| 8 | G-43 | 166,807 | 167,594 | 174,069 | 344,386 | 494,844 | 739,091 | 898,356 | 789,251 | 887,845 | 431,285 | 198,246 | 206,223 | 5,497,997 |
| 9 | G-51 | 205,360 | 211,977 | 200,232 | 295,358 | 323,777 | 471,923 | 564,591 | 508,544 | 443,677 | 347,416 | 248,730 | 200,183 | 4,021,769 |
| 10 | G-52 | 405,927 | 395,010 | 389,743 | 539,909 | 564,349 | 798,395 | 860,364 | 758,181 | 678,341 | 570,066 | 429,517 | 404,402 | 6,794,203 |
| 11 | G-53 | 547,450 | 611,315 | 621,914 | 1,006,376 | 812,774 | 994,863 | 1,125,681 | 1,006,035 | 972,596 | 923,508 | 705,163 | 490,422 | 9,818,096 |
| 12 | G-54 | 12,699 | 11,833 | 18,023 | 28,445 | 18,524 | 12,848 | 16,407 | 22,427 | 22,528 | 24,305 | 22,167 | 18,486 | 228,693 |
| 13 | G-63 | 1,369,430 | 1,474,260 | 1,222,465 | 1,404,140 | 1,062,999 | 916,186 | 1,040,189 | 785,409 | 632,616 | 1,001,840 | 1,078,611 | 1,194,124 | 13,182,269 |
| 14 | Total C/I | 3,489,939 | 3,737,501 | 3,805,774 | 6,244,013 | 7,787,635 | 11,593,397 | 14,187,299 | 12,339,383 | 10,642,990 | 7,424,010 | 4,753,343 | 3,534,260 | 89,539,543 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 4,810,299 | 5,108,259 | 5,414,949 | 9,652,295 | 13,445,619 | 20,866,909 | 25,605,959 | 22,123,967 | 18,601,758 | 12,332,858 | 7,364,707 | 5,041,460 | 150,369,039 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 4,810,299 | 5,108,259 | 5,414,949 | 9,652,295 | 13,445,619 | 20,866,909 | 25,605,959 | 22,123,967 | 18,601,758 | 12,332,858 | 7,364,707 | 5,041,460 | 150,369,039 |

**EnergyNorth Natural Gas Inc**
**Test Year July 2006 - June 2007**
**Development of Billing Determinants**

Adjusted Billing Determinants

Actual Calendar Month Sales- DRY THERMS

| | | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Dry Monthly Therm | 1.055 | 1.053 | 1.041 | 1.038 | 1.050 | 1.034 | 1.029 | 1.047 | 1.050 | 1.062 | 1.078 | 1.0650 | |
| | Wet Monthly Therm | 1.037 | 1.035 | 1.023 | 1.020 | 1.032 | 1.016 | 1.011 | 1.029 | 1.032 | 1.043 | 1.059 | 1.0460 | |
| 1 | R-1 | 60,214 | 61,100 | 61,263 | 89,429 | 95,037 | 131,414 | 146,427 | 141,358 | 123,869 | 108,829 | 73,860 | 62,192 | 1,154,994 |
| 2 | R-3 | 1,169,574 | 1,228,237 | 1,435,351 | 3,097,550 | 4,551,860 | 7,267,307 | 9,635,174 | 9,761,833 | 7,299,259 | 4,589,392 | 2,121,493 | 1,322,948 | 53,479,978 |
| 3 | R-4 | 90,573 | 81,422 | 90,554 | 131,346 | 160,489 | 353,830 | 568,227 | 727,337 | 758,224 | 578,469 | 223,098 | 106,982 | 3,870,549 |
| 4 | Total Residential | 1,320,360 | 1,370,758 | 1,587,168 | 3,318,325 | 4,807,386 | 7,752,551 | 10,349,828 | 10,630,529 | 8,181,352 | 5,276,690 | 2,418,451 | 1,492,122 | 58,505,521 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 203,998 | 215,261 | 337,433 | 823,531 | 1,352,429 | 2,403,973 | 3,487,612 | 3,744,215 | 2,783,610 | 1,614,636 | 629,036 | 311,367 | 17,907,103 |
| 7 | G-42 | 578,266 | 650,251 | 815,371 | 1,723,110 | 2,433,020 | 3,930,239 | 5,243,561 | 5,494,808 | 4,431,692 | 2,854,630 | 1,249,600 | 692,365 | 30,096,913 |
| 8 | G-43 | 166,807 | 167,594 | 172,508 | 336,274 | 437,364 | 629,377 | 821,069 | 853,991 | 912,417 | 459,596 | 191,058 | 200,621 | 5,348,676 |
| 9 | G-51 | 205,360 | 211,977 | 199,776 | 291,327 | 296,496 | 421,504 | 527,322 | 541,354 | 451,481 | 363,603 | 242,342 | 200,183 | 3,952,725 |
| 10 | G-52 | 405,927 | 395,010 | 388,744 | 533,619 | 523,908 | 722,527 | 813,378 | 799,646 | 687,444 | 591,827 | 423,801 | 402,810 | 6,688,642 |
| 11 | G-53 | 547,450 | 611,315 | 616,392 | 990,825 | 767,639 | 915,906 | 1,069,325 | 1,050,779 | 986,976 | 959,591 | 689,407 | 490,422 | 9,696,028 |
| 12 | G-54 | 12,699 | 11,833 | 17,973 | 27,850 | 18,524 | 12,848 | 16,407 | 23,193 | 22,795 | 25,181 | 21,182 | 18,260 | 228,746 |
| 13 | G-63 | 1,369,430 | 1,474,260 | 1,222,465 | 1,404,140 | 1,062,999 | 916,186 | 1,040,189 | 785,409 | 632,616 | 1,001,840 | 1,078,611 | 1,194,124 | 13,182,269 |
| 14 | Total C/I | 3,489,939 | 3,737,501 | 3,770,662 | 6,130,675 | 6,892,379 | 9,952,559 | 13,018,864 | 13,293,394 | 10,909,032 | 7,870,906 | 4,525,036 | 3,510,153 | 87,101,101 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 4,810,299 | 5,108,259 | 5,357,831 | 9,449,000 | 11,699,765 | 17,705,110 | 23,368,691 | 23,923,923 | 19,090,384 | 13,147,596 | 6,943,488 | 5,002,275 | 145,606,622 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportation Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 4,810,299 | 5,108,259 | 5,357,831 | 9,449,000 | 11,699,765 | 17,705,110 | 23,368,691 | 23,923,923 | 19,090,384 | 13,147,596 | 6,943,488 | 5,002,275 | 145,606,622 |

EnergyNorth Natural Gas, Inc.
Analysis of Individual C&I Records
Customer Sales Statistics



Calendar Month Sales & Transportation

| | Class Descriptions | Rate Code | 2006 July | 2006 August | 2006 September | 2006 October | 2006 November | 2006 December | 2007 January | 2007 February | 2007 March | 2007 April | 2007 May | 2007 June | 12 Month Total | Winter | Summer |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential Non-Heating | R-1 | 59,166 | 60,055 | 60,204 | 87,879 | 93,408 | 129,126 | 143,866 | 138,928 | 121,746 | 106,882 | 72,559 | 61,083 | 1,134,922 | 733,957 | 400,966 |
| 2 | Residential Heating | R-3 | 1,149,619 | 1,207,242 | 1,431,185 | 3,129,713 | 5,280,086 | 8,565,317 | 10,458,931 | 8,820,132 | 6,976,112 | 4,187,665 | 2,254,308 | 1,312,340 | 54,772,651 | 44,288,244 | 10,484,407 |
| 3 | Low Income Discount Res Heating | R-4 | 89,028 | 80,030 | 89,962 | 131,587 | 187,495 | 417,634 | 616,121 | 657,307 | 724,474 | 526,478 | 238,471 | 106,687 | 3,865,474 | 3,129,509 | 735,965 |
| 4 | C&I - Low Annual Use, High Winter Use | G-41 | 200,517 | 211,582 | 341,631 | 636,873 | 1,601,238 | 2,880,814 | 3,814,051 | 3,364,250 | 2,652,802 | 1,455,589 | 692,223 | 314,949 | 18,367,519 | 15,769,744 | 2,597,774 |
| 5 | C&I-Medium Annual Use, High Winter Use | G-42 | 568,400 | 639,135 | 817,305 | 1,742,999 | 2,831,810 | 4,645,929 | 5,698,300 | 4,959,679 | 4,232,492 | 2,595,190 | 1,342,185 | 687,268 | 30,760,693 | 24,963,399 | 5,797,293 |
| 6 | C&I - High Annual Use, High Winter Use | G-43 | 163,961 | 164,729 | 171,059 | 338,414 | 486,361 | 726,225 | 882,641 | 775,682 | 872,625 | 423,569 | 194,752 | 202,543 | 5,402,563 | 4,167,103 | 1,235,459 |
| 7 | C&I - Low Annual Use, Low Winter Use | G-51 | 201,856 | 208,353 | 195,770 | 290,237 | 318,226 | 463,708 | 554,715 | 499,801 | 436,071 | 341,200 | 244,346 | 196,612 | 3,951,896 | 2,613,722 | 1,338,174 |
| 8 | C&I - Medium Annual Use, Low Winter Use | G-52 | 399,002 | 368,258 | 383,004 | 530,546 | 554,674 | 784,496 | 845,314 | 745,146 | 666,712 | 559,067 | 421,946 | 397,187 | 6,676,153 | 4,156,210 | 2,519,943 |
| 9 | C&I - High Annual Use Load Factor Less Th | G-53 | 538,110 | 600,865 | 611,160 | 988,924 | 798,841 | 977,545 | 1,105,990 | 988,739 | 955,923 | 906,965 | 692,734 | 481,673 | 9,647,489 | 5,734,022 | 3,913,466 |
| 10 | C&I - High Annual Use Load Factor Less Th | G-54 | 12,483 | 11,631 | 17,712 | 27,952 | 18,206 | 12,624 | 16,120 | 22,041 | 22,142 | 23,871 | 21,776 | 18,156 | 224,714 | 115,005 | 109,709 |
| 11 | C&I - High Annual Use Load Factor Greater | G-63 | 1,346,066 | 1,449,059 | 1,201,327 | 1,379,790 | 1,044,776 | 900,237 | 1,021,994 | 771,906 | 621,772 | 983,917 | 1,059,600 | 1,172,820 | 12,953,263 | 5,344,601 | 7,608,662 |
| 12 | Total | | 4,726,227 | 5,020,939 | 5,321,318 | 9,464,914 | 13,215,123 | 20,503,656 | 25,158,042 | 21,743,612 | 18,282,071 | 12,112,214 | 7,234,902 | 4,951,518 | 147,757,335 | 111,015,516 | 36,741,819 |

Actual

| | Class Descriptions | Rate Code | 2006 July | 2006 August | 2006 September | 2006 October | 2006 November | 2006 December | 2007 January | 2007 February | 2007 March | 2007 April | 2007 May | 2007 June | 12 Month Total | Winter | Summer |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | Residential Non-Heating | R-1 | 59,186 | 60,055 | 60,204 | 87,879 | 93,408 | 129,126 | 143,866 | 138,928 | 121,746 | 106,882 | 72,559 | 61,083 | 1,134,922 | 733,957 | 400,966 |
| 14 | Residential Heating | R-3 | 1,149,619 | 1,207,242 | 1,410,532 | 3,043,835 | 4,473,828 | 7,140,797 | 9,466,628 | 9,594,008 | 7,174,129 | 4,507,284 | 2,084,102 | 1,299,346 | 52,551,350 | 42,356,674 | 10,194,676 |
| 15 | Low Income Discount Res Heating | R-4 | 89,028 | 80,030 | 88,988 | 129,068 | 157,737 | 347,671 | 558,287 | 714,833 | 745,226 | 568,120 | 219,165 | 105,073 | 3,803,225 | 3,091,674 | 711,352 |
| 16 | C&I - Low Annual Use, High Winter Use | G-41 | 200,517 | 211,582 | 331,598 | 809,251 | 1,329,245 | 2,362,124 | 3,426,604 | 3,679,845 | 2,735,891 | 1,585,749 | 617,949 | 305,813 | 17,596,168 | 15,119,458 | 2,476,709 |
| 17 | C&I-Medium Annual Use, High Winter Use | G-42 | 568,400 | 639,135 | 801,273 | 1,693,230 | 2,391,311 | 3,861,821 | 5,151,836 | 5,400,341 | 4,355,720 | 2,803,558 | 1,227,576 | 680,013 | 29,574,214 | 23,964,588 | 5,609,626 |
| 18 | C&I - High Annual Use, High Winter Use | G-43 | 163,961 | 164,729 | 169,525 | 330,442 | 429,867 | 618,421 | 806,707 | 839,309 | 896,776 | 451,373 | 187,690 | 197,042 | 5,255,842 | 4,042,452 | 1,213,390 |
| 19 | C&I - Low Annual Use, Low Winter Use | G-51 | 201,856 | 208,353 | 196,322 | 286,275 | 291,413 | 414,166 | 518,097 | 532,047 | 443,741 | 357,098 | 238,071 | 196,612 | 3,884,053 | 2,556,563 | 1,327,490 |
| 20 | C&I - Medium Annual Use, Low Winter Use | G-52 | 399,002 | 388,258 | 302,022 | 524,365 | 514,926 | 709,949 | 799,150 | 785,899 | 675,659 | 581,239 | 416,332 | 395,624 | 6,572,425 | 4,066,822 | 2,505,602 |
| 21 | C&I - High Annual Use Load Factor Less Th | G-53 | 538,110 | 600,865 | 605,734 | 973,643 | 754,480 | 899,961 | 1,050,620 | 1,032,714 | 970,057 | 942,424 | 677,256 | 481,673 | 9,527,536 | 5,650,255 | 3,877,280 |
| 22 | C&I - High Annual Use Load Factor Less Th | G-54 | 12,483 | 11,631 | 17,662 | 27,367 | 18,206 | 12,624 | 16,120 | 22,794 | 22,405 | 24,731 | 20,808 | 17,935 | 224,766 | 116,880 | 107,885 |
| 23 | C&I - High Annual Use Load Factor Greater | G-63 | 1,346,066 | 1,449,059 | 1,201,327 | 1,379,790 | 1,044,776 | 900,237 | 1,021,994 | 771,906 | 621,772 | 983,917 | 1,059,600 | 1,172,820 | 12,953,263 | 5,344,601 | 7,608,662 |
| 24 | Total | | 4,728,227 | 5,020,939 | 5,265,168 | 9,285,145 | 11,499,198 | 17,396,897 | 22,959,910 | 23,512,623 | 18,763,121 | 12,912,375 | 6,821,107 | 4,913,033 | 143,077,763 | 107,044,124 | 36,033,639 |

Weather

| | Class Descriptions | Rate Code | 2006 July | 2006 August | 2006 September | 2006 October | 2006 November | 2006 December | 2007 January | 2007 February | 2007 March | 2007 April | 2007 May | 2007 June | 12 Month Total | Winter | Summer |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 25 | Residential Non-Heating | R-1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | Residential Heating | R-3 | 0 | 0 | 20,663 | 85,877 | 806,260 | 1,424,520 | 992,302 | (773,875) | (198,017) | (319,620) | 170,207 | 12,994 | 2,221,301 | 1,931,570 | 289,731 |
| 27 | Low Income Discount Res Heating | R-4 | 0 | 0 | 973 | 2,520 | 29,757 | 69,954 | 57,834 | (57,526) | (20,752) | (41,641) | 19,306 | 1,814 | 62,248 | 37,635 | 24,613 |
| 28 | C&I - Low Annual Use, High Winter Use | G-41 | 0 | 0 | 10,033 | 27,822 | 271,993 | 518,690 | 387,447 | (315,595) | (83,089) | (129,160) | 74,274 | 9,136 | 771,351 | 650,286 | 121,065 |
| 29 | C&I-Medium Annual Use, High Winter Use | G-42 | 0 | 0 | 16,033 | 49,769 | 440,499 | 784,108 | 546,463 | (440,662) | (123,228) | (200,368) | 114,610 | 7,255 | 1,166,478 | 998,811 | 187,667 |
| 30 | C&I - High Annual Use, High Winter Use | G-43 | 0 | 0 | 1,534 | 7,972 | 55,495 | 107,804 | 75,935 | (63,627) | (24,151) | (27,804) | 7,062 | 5,501 | 146,721 | 124,651 | 22,070 |
| 31 | C&I - Low Annual Use, Low Winter Use | G-51 | 0 | 0 | 448 | 3,951 | 26,813 | 49,542 | 36,618 | (32,246) | (7,670) | (15,898) | 6,275 | 0 | 67,844 | 57,159 | 10,684 |
| 32 | C&I - Medium Annual Use, Low Winter Use | G-52 | 0 | 0 | 982 | 6,181 | 39,746 | 74,547 | 46,164 | (40,752) | (8,947) | (21,372) | 5,615 | 1,563 | 103,728 | 89,368 | 14,340 |
| 33 | C&I - High Annual Use Load Factor Less Th | G-53 | 0 | 0 | 5,426 | 15,281 | 44,361 | 77,593 | 55,370 | (43,975) | (14,134) | (35,438) | 15,478 | 0 | 119,953 | 83,767 | 36,186 |
| 34 | C&I - High Annual Use Load Factor Less Th | G-54 | 0 | 0 | 50 | 585 | 0 | 0 | 0 | (753) | (263) | (860) | 968 | 221 | (52) | (1,875) | 1,824 |
| 35 | C&I - High Annual Use Load Factor Greater | G-63 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - | - |
| 36 | Total | | 0 | 0 | 56,130 | 199,769 | 1,715,925 | 3,106,750 | 2,198,132 | (1,769,011) | (480,250) | (800,162) | 413,795 | 38,485 | 4,679,572 | 3,971,393 | 708,180 |

**Total Weather Normalized- DRY**

| | Class Descriptions | Rate Code | 2006 July | 2006 August | 2006 September | 2006 October | 2006 November | 2006 December | 2007 January | 2007 February | 2007 March | 2007 April | 2007 May | 2007 June | 12 Month Total | Winter | Summer |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential Non-Heating | R-1 | 60,214 | 61,100 | 61,263 | 89,429 | 95,037 | 131,414 | 146,427 | 141,358 | 123,869 | 108,829 | 73,860 | 62,192 | 1,154,994 | 746,936 | 408,059 |
| 2 | Residential Heating | R-3 | 1,169,574 | 1,228,237 | 1,456,367 | 3,184,943 | 5,372,183 | 8,717,064 | 10,645,143 | 8,974,420 | 7,097,788 | 4,263,950 | 2,294,754 | 1,336,178 | 55,740,602 | 45,070,549 | 10,670,053 |
| 3 | Low Income Discount Res Heating | R-4 | 90,573 | 81,422 | 91,544 | 133,910 | 190,765 | 425,033 | 627,090 | 668,805 | 737,111 | 536,069 | 242,750 | 108,829 | 3,933,900 | 3,184,873 | 749,027 |
| 4 | C&I - Low Annual Use, High Winter Use | G-41 | 203,998 | 215,261 | 347,642 | 851,641 | 1,629,166 | 2,931,852 | 3,861,957 | 3,423,100 | 2,699,072 | 1,483,123 | 704,642 | 320,670 | 18,692,125 | 16,048,271 | 2,643,854 |
| 5 | C&I-Medium Annual Use, High Winter Use | G-42 | 578,266 | 650,251 | 831,686 | 1,773,758 | 2,881,202 | 4,728,239 | 5,799,753 | 5,046,437 | 4,306,314 | 2,642,466 | 1,366,267 | 699,752 | 31,304,390 | 25,404,411 | 5,899,979 |
| 6 | C&I - High Annual Use, High Winter Use | G-43 | 166,807 | 167,594 | 174,069 | 344,386 | 494,844 | 739,091 | 898,356 | 789,251 | 887,845 | 431,285 | 198,246 | 206,223 | 5,497,997 | 4,240,672 | 1,257,325 |
| 7 | C&I - Low Annual Use, Low Winter Use | G-51 | 205,360 | 211,977 | 200,232 | 295,358 | 323,777 | 471,923 | 564,591 | 508,544 | 443,677 | 347,416 | 248,730 | 200,183 | 4,021,769 | 2,659,928 | 1,361,841 |
| 8 | C&I - Medium Annual Use, Low Winter Use | G-52 | 405,927 | 395,010 | 389,743 | 539,909 | 564,349 | 798,395 | 860,364 | 758,181 | 678,341 | 570,066 | 429,517 | 404,402 | 6,794,203 | 4,229,696 | 2,564,508 |
| 9 | C&I - High Annual Use Load Factor Less Th | G-53 | 547,450 | 611,315 | 621,914 | 1,006,376 | 812,774 | 994,863 | 1,125,681 | 1,006,035 | 972,596 | 923,508 | 705,163 | 490,422 | 9,818,096 | 5,835,457 | 3,982,639 |
| 10 | C&I - High Annual Use Load Factor Less Th | G-54 | 12,699 | 11,833 | 18,023 | 28,445 | 18,524 | 12,848 | 16,407 | 22,427 | 22,528 | 24,305 | 22,167 | 18,486 | 228,693 | 117,040 | 111,654 |
| 11 | C&I - High Annual Use Load Factor Greater | G-63 | 1,369,430 | 1,474,260 | 1,222,465 | 1,404,140 | 1,062,999 | 916,186 | 1,040,189 | 785,409 | 632,616 | 1,001,840 | 1,078,611 | 1,194,124 | 13,182,269 | 5,439,240 | 7,743,029 |
| 12 | Total | | 4,810,299 | 5,108,259 | 5,414,949 | 9,652,295 | 13,445,619 | 20,866,909 | 25,605,959 | 22,123,967 | 18,601,758 | 12,332,858 | 7,364,707 | 5,041,460 | 150,369,039 | 112,977,070 | 37,391,960 |

**Total Actual Calendar- DRY**

| | Class Descriptions | Rate Code | 2006 July | 2006 August | 2006 September | 2006 October | 2006 November | 2006 December | 2007 January | 2007 February | 2007 March | 2007 April | 2007 May | 2007 June | 12 Month Total | Winter | Summer |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential Non-Heating | R-1 | 60,214 | 61,100 | 61,263 | 89,429 | 95,037 | 131,414 | 146,427 | 141,358 | 123,869 | 108,829 | 73,860 | 62,192 | 1,154,994 | 746,936 | 408,059 |
| 2 | Residential Heating | R-3 | 1,169,574 | 1,228,237 | 1,435,351 | 3,097,550 | 4,551,860 | 7,267,307 | 9,635,174 | 9,761,833 | 7,299,259 | 4,589,392 | 2,121,493 | 1,322,948 | 53,479,978 | 43,104,824 | 10,375,153 |
| 3 | Low Income Discount Res Heating | R-4 | 90,573 | 81,422 | 90,554 | 131,346 | 160,489 | 353,830 | 568,227 | 727,337 | 758,224 | 578,469 | 223,098 | 106,982 | 3,870,549 | 3,146,576 | 723,973 |
| 4 | C&I - Low Annual Use, High Winter Use | G-41 | 203,998 | 215,261 | 337,433 | 823,531 | 1,352,429 | 2,403,973 | 3,487,612 | 3,744,215 | 2,783,610 | 1,614,636 | 629,036 | 311,367 | 17,907,103 | 15,386,476 | 2,520,627 |
| 5 | C&I-Medium Annual Use, High Winter Use | G-42 | 578,266 | 650,251 | 815,371 | 1,723,110 | 2,433,020 | 3,930,239 | 5,243,561 | 5,494,808 | 4,431,692 | 2,854,630 | 1,249,600 | 692,365 | 30,096,913 | 24,387,949 | 5,708,964 |
| 6 | C&I - High Annual Use, High Winter Use | G-43 | 166,807 | 167,594 | 172,508 | 336,274 | 437,364 | 629,377 | 821,069 | 853,991 | 912,417 | 459,696 | 191,058 | 200,621 | 5,348,676 | 4,113,815 | 1,234,861 |
| 7 | C&I - Low Annual Use, Low Winter Use | G-51 | 205,360 | 211,977 | 199,776 | 291,327 | 296,496 | 421,504 | 527,322 | 541,354 | 451,481 | 363,603 | 242,342 | 200,183 | 3,952,725 | 2,601,759 | 1,350,966 |
| 8 | C&I - Medium Annual Use, Low Winter Use | G-52 | 405,927 | 395,010 | 388,744 | 533,619 | 523,908 | 722,527 | 813,378 | 799,646 | 687,444 | 591,827 | 423,801 | 402,810 | 6,688,642 | 4,138,730 | 2,549,912 |
| 9 | C&I - High Annual Use Load Factor Less Th | G-53 | 547,450 | 611,315 | 616,392 | 990,825 | 767,639 | 915,906 | 1,069,325 | 1,050,779 | 986,976 | 959,591 | 689,407 | 490,422 | 9,696,028 | 5,750,217 | 3,945,811 |
| 10 | C&I - High Annual Use Load Factor Less Th | G-54 | 12,699 | 11,833 | 17,973 | 27,850 | 18,524 | 12,048 | 16,407 | 23,193 | 22,795 | 25,161 | 21,182 | 18,260 | 228,746 | 118,948 | 109,797 |
| 11 | C&I - High Annual Use Load Factor Greater | G-63 | 1,369,430 | 1,474,260 | 1,222,465 | 1,404,140 | 1,062,999 | 916,166 | 1,040,189 | 785,409 | 632,616 | 1,001,840 | 1,078,611 | 1,194,124 | 13,182,269 | 5,439,240 | 7,743,029 |
| 12 | Total | | 4,810,299 | 5,108,259 | 5,357,831 | 9,449,[illegible]00 | 11,599,765 | 17,705,110 | 23,368,691 | 23,923,923 | 19,090,384 | 13,147,596 | 6,943,488 | 5,002,275 | 145,606,622 | 108,935,470 | 36,671,152 |

**EnergyNorth Natural Gas Inc**
**Test Year July 2006 - June 2007**
**Development of Billing Determinants**

**Development of Pro Forma Revenue**

Per Books Data

**Cost of Gas Revenue:**

| | Revenue | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 62,343 | 51,733 | 58,255 | 67,268 | 84,882 | 130,600 | 149,017 | 162,781 | 167,104 | 133,873 | 104,298 | 75,332 | 1,247,486 |
| 2 | R-3 | 1,223,586 | 1,022,845 | 1,187,054 | 1,797,010 | 3,872,317 | 6,772,481 | 9,022,121 | 11,937,999 | 11,084,808 | 7,114,059 | 3,632,561 | 1,796,200 | 60,463,043 |
| 3 | R-4 | 111,477 | 68,623 | 78,055 | 109,263 | 108,245 | 279,052 | 501,727 | 745,323 | 960,478 | 849,382 | 476,767 | 134,697 | 4,423,088 |
| 4 | Total Residential | 1,397,405 | 1,143,201 | 1,323,363 | 1,973,542 | 4,065,444 | 7,182,133 | 9,672,865 | 12,846,104 | 12,212,390 | 8,097,314 | 4,213,627 | 2,006,229 | 66,133,617 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 239,265 | 202,355 | 232,264 | 394,716 | 1,013,904 | 1,940,811 | 2,954,136 | 4,077,692 | 3,986,983 | 2,376,236 | 1,092,836 | 383,281 | 18,894,477 |
| 7 | G-42 | 483,990 | 393,425 | 503,032 | 831,340 | 1,726,169 | 2,949,727 | 4,172,781 | 5,217,361 | 5,326,768 | 3,568,561 | 1,807,021 | 767,157 | 27,747,332 |
| 8 | G-43 | 59,415 | 72,707 | 70,336 | 104,895 | 219,746 | 313,156 | 426,437 | 510,192 | 535,787 | 405,321 | 166,516 | 136,499 | 3,021,007 |
| 9 | G-51 | 181,510 | 175,089 | 171,357 | 197,992 | 244,939 | 366,661 | 464,487 | 586,483 | 584,783 | 426,002 | 300,347 | 225,632 | 3,925,281 |
| 10 | G-52 | 358,075 | 262,162 | 302,681 | 329,002 | 373,782 | 572,773 | 671,887 | 749,688 | 752,173 | 580,016 | 433,601 | 339,190 | 5,725,030 |
| 11 | G-53 | 29,380 | 92,488 | 46,266 | 129,086 | 53,317 | 79,225 | 86,521 | 140,470 | 120,096 | 97,346 | 61,985 | 47,709 | 983,889 |
| 12 | G-54 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | G-63 | 22,777 | 16,814 | 27,344 | 24,485 | 30,848 | 34,948 | 43,614 | 47,463 | 32,033 | 28,173 | 8,299 | 3,807 | 320,603 |
| 14 | Total C/I | 1,374,413 | 1,215,038 | 1,353,279 | 2,011,517 | 3,662,704 | 6,257,302 | 8,819,863 | 11,329,350 | 11,338,624 | 7,481,654 | 3,870,604 | 1,903,273 | 60,617,620 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 2,771,818 | 2,358,239 | 2,676,643 | 3,985,059 | 7,728,147 | 13,439,435 | 18,492,728 | 24,175,453 | 23,551,014 | 15,578,968 | 8,084,231 | 3,909,502 | 126,751,237 |
| 17 | | | | | | | | | | | | | | |
| 18 | G-41T | 0 | 0 | 0 | 0 | 26 | 102 | 132 | 237 | 234 | 145 | 63 | 0 | 940 |
| 19 | G-42T | 0 | 0 | 0 | 0 | 133 | 401 | 537 | 758 | 785 | 520 | 211 | 0 | 3,346 |
| 20 | G-43T | 0 | 0 | 0 | 0 | 9 | 180 | 238 | 326 | 321 | 483 | (38) | 0 | 1,519 |
| 21 | G-51T | 0 | 0 | 0 | 0 | 8 | 23 | 25 | 30 | 32 | 28 | 13 | 0 | 160 |
| 22 | G-52T | 0 | 0 | 0 | 0 | 28 | 100 | 102 | 115 | 137 | 95 | 57 | 0 | 632 |
| 23 | G-53T | 0 | 0 | 0 | 0 | 0 | 568 | 655 | 772 | 739 | 691 | 611 | 0 | 4,036 |
| 24 | G-54T | 0 | 0 | 0 | 0 | 18 | 10 | 0 | 17 | 20 | 17 | 19 | 0 | 101 |
| 25 | G-63T | 0 | 0 | 0 | 0 | 0 | 640 | 598 | 846 | 379 | 552 | 806 | 0 | 3,821 |
| 26 | Total Firm Trans | 0 | 0 | 0 | 0 | 221 | 2,024 | 2,288 | 3,102 | 2,647 | 2,531 | 1,741 | 0 | 14,554 |
| 27 | | | | | | | | | | | | | | |
| 28 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 29 | | | | | | | | | | | | | | |
| 30 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 31 | | | | | | | | | | | | | | |
| 32 | Non-firm Transportatio | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 33 | | | | | | | | | | | | | | |
| 34 | Total | 2,771,818 | 2,358,239 | 2,676,643 | 3,985,059 | 7,728,369 | 13,441,459 | 18,495,016 | 24,178,556 | 23,553,661 | 15,581,498 | 8,085,972 | 3,909,502 | 126,765,791 |

**EnergyNorth Natural Gas Inc**
**Test Year July 2006 - June 2007**
**Development of Billing Determinants**

**Development of Pro Forma Revenue**

Adjustments to Per Books Data

**Weather Normalization Adjustments to Gas Cost Revenue:**

| | Gas Cost Adjustments | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | R-3 | 0 | 0 | 20,316 | 83,388 | 853,699 | 1,708,520 | 1,188,277 | (894,423) | (234,743) | (392,908) | 195,924 | 13,689 | 2,541,739 |
| 3 | R-4 | 0 | 0 | 953 | 2,457 | 31,309 | 83,073 | 69,047 | (66,810) | (24,416) | (50,025) | 22,393 | 1,917 | 69,898 |
| 4 | Total Residential | 0 | 0 | 21,269 | 85,845 | 885,008 | 1,791,594 | 1,257,324 | (961,233) | (259,159) | (442,933) | 218,318 | 15,606 | 2,611,638 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 0 | 0 | 9,882 | 26,811 | 286,567 | 618,097 | 460,995 | (362,188) | (97,457) | (158,233) | 86,208 | 9,655 | 880,338 |
| 7 | G-42 | 0 | 0 | 14,997 | 48,465 | 462,925 | 932,514 | 650,055 | (505,746) | (144,502) | (254,803) | 132,481 | 7,537 | 1,343,925 |
| 8 | G-43 | 0 | 0 | 1,514 | 7,761 | 59,348 | 126,630 | 89,626 | (72,106) | (28,117) | (33,691) | 8,116 | 5,803 | 164,883 |
| 9 | G-51 | 0 | 0 | 438 | 3,858 | 27,964 | 58,799 | 43,428 | (36,917) | (9,007) | (19,419) | 7,137 | 0 | 76,281 |
| 10 | G-52 | 0 | 0 | 960 | 6,032 | 41,063 | 88,495 | 54,826 | (46,713) | (10,509) | (26,138) | 6,403 | 1,648 | 116,068 |
| 11 | G-53 | 0 | 0 | 5,283 | 14,823 | 45,573 | 91,109 | 65,136 | (49,871) | (16,212) | (43,279) | 17,821 | 0 | 130,383 |
| 12 | G-54 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | G-63 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total C/I | 0 | 0 | 33,073 | 107,750 | 923,440 | 1,915,644 | 1,364,067 | (1,073,542) | (305,804) | (535,562) | 258,167 | 24,643 | 2,711,878 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 0 | 0 | 54,343 | 193,595 | 1,808,449 | 3,707,238 | 2,621,391 | (2,034,775) | (564,963) | (978,495) | 476,485 | 40,249 | 5,323,516 |
| 17 | | | | | | | | | | | | | | |
| 18 | G-41T | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | G-42T | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | G-43T | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | G-51T | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | G-52T | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 23 | G-53T | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | G-54T | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 25 | G-63T | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | Total Firm Trans | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 27 | | | | | | | | | | | | | | |
| 28 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 29 | | | | | | | | | | | | | | |
| 30 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 31 | | | | | | | | | | | | | | |
| 32 | Non-firm Transportatio | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 33 | | | | | | | | | | | | | | |
| 34 | Total | 0 | 0 | 54,343 | 193,595 | 1,808,449 | 3,707,238 | 2,621,391 | (2,034,775) | (564,963) | (978,495) | 476,485 | 40,249 | 5,323,516 |

Adjusted Billing Determinants

**Weather Normalized Gas Cost Revenue**

| | Normalized Gas Costs | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 62,343 | 51,733 | 56,255 | 67,268 | 64,882 | 130,600 | 149,017 | 162,781 | 167,104 | 133,873 | 104,298 | 75,332 | 1,247,486 |
| 2 | R-3 | 1,223,586 | 1,022,845 | 1,207,370 | 1,880,399 | 4,726,016 | 8,481,001 | 10,210,398 | 11,043,576 | 10,850,066 | 6,721,151 | 3,828,486 | 1,809,889 | 63,004,762 |
| 3 | R-4 | 111,477 | 68,623 | 79,008 | 111,720 | 139,554 | 362,125 | 570,774 | 678,513 | 936,062 | 799,356 | 499,160 | 136,614 | 4,492,987 |
| 4 | Total Residential | 1,397,405 | 1,143,201 | 1,344,633 | 2,059,387 | 4,950,452 | 8,973,727 | 10,930,189 | 11,884,871 | 11,953,231 | 7,654,381 | 4,431,944 | 2,021,834 | 68,745,255 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 239,265 | 202,355 | 242,146 | 421,528 | 1,300,471 | 2,558,908 | 3,415,131 | 3,715,504 | 3,889,525 | 2,218,003 | 1,179,044 | 392,935 | 19,774,815 |
| 7 | G-42 | 483,990 | 393,425 | 518,029 | 879,805 | 2,189,095 | 3,882,241 | 4,822,836 | 4,711,615 | 5,182,267 | 3,313,758 | 1,939,502 | 774,694 | 29,091,257 |
| 8 | G-43 | 59,415 | 72,707 | 71,850 | 112,656 | 279,094 | 439,786 | 516,063 | 438,086 | 507,670 | 371,629 | 174,633 | 142,302 | 3,185,890 |
| 9 | G-51 | 181,510 | 175,089 | 171,795 | 201,850 | 272,903 | 425,460 | 507,915 | 549,566 | 575,777 | 406,583 | 307,484 | 225,632 | 4,001,563 |
| 10 | G-52 | 358,075 | 262,162 | 303,641 | 335,034 | 414,845 | 661,269 | 726,713 | 702,975 | 741,664 | 553,878 | 440,004 | 340,838 | 5,841,098 |
| 11 | G-53 | 29,380 | 92,488 | 51,548 | 143,909 | 98,889 | 170,334 | 151,657 | 90,599 | 103,884 | 54,068 | 79,806 | 47,709 | 1,114,272 |
| 12 | G-54 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | G-63 | 22,777 | 16,814 | 27,344 | 24,485 | 30,848 | 34,948 | 43,614 | 47,463 | 32,033 | 28,173 | 8,299 | 3,807 | 320,603 |
| 14 | Total C/I | 1,374,413 | 1,215,038 | 1,386,353 | 2,119,267 | 4,586,144 | 8,172,946 | 10,183,930 | 10,255,808 | 11,032,820 | 6,946,091 | 4,128,772 | 1,927,917 | 63,329,498 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 2,771,818 | 2,358,239 | 2,730,986 | 4,178,654 | 9,536,596 | 17,146,673 | 21,114,119 | 22,140,678 | 22,986,051 | 14,600,472 | 8,560,716 | 3,949,751 | 132,074,753 |
| 17 | | | | | | | | | | | | | | |
| 18 | G-41T | 0 | 0 | 0 | 0 | 26 | 102 | 132 | 237 | 234 | 145 | 63 | 0 | 940 |
| 19 | G-42T | 0 | 0 | 0 | 0 | 133 | 401 | 537 | 758 | 785 | 520 | 211 | 0 | 3,346 |
| 20 | G-43T | 0 | 0 | 0 | 0 | 9 | 180 | 238 | 326 | 321 | 483 | (38) | 0 | 1,519 |
| 21 | G-51T | 0 | 0 | 0 | 0 | 8 | 23 | 25 | 30 | 32 | 28 | 13 | 0 | 160 |
| 22 | G-52T | 0 | 0 | 0 | 0 | 28 | 100 | 102 | 115 | 137 | 95 | 57 | 0 | 632 |
| 23 | G-53T | 0 | 0 | 0 | 0 | 0 | 568 | 655 | 772 | 739 | 691 | 611 | 0 | 4,036 |
| 24 | G-54T | 0 | 0 | 0 | 0 | 18 | 10 | 0 | 17 | 20 | 17 | 19 | 0 | 101 |
| 25 | G-63T | 0 | 0 | 0 | 0 | 0 | 640 | 598 | 846 | 379 | 552 | 806 | 0 | 3,821 |
| 26 | Total Firm Trans | 0 | 0 | 0 | 0 | 221 | 2,024 | 2,288 | 3,102 | 2,647 | 2,531 | 1,741 | 0 | 14,554 |
| 27 | | | | | | | | | | | | | | |
| 28 | 260 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 29 | | | | | | | | | | | | | | |
| 30 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 31 | | | | | | | | | | | | | | |
| 32 | Non-firm Transportatio | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 33 | | | | | | | | | | | | | | |
| 34 | Total | 2,771,818 | 2,358,239 | 2,730,986 | 4,178,654 | 9,536,817 | 17,148,697 | 21,116,406 | 22,143,781 | 22,988,698 | 14,603,003 | 8,562,457 | 3,949,751 | 132,089,307 |

**EnergyNorth Natural Gas Inc**
**Test Year July 2006 - June 2007**
**Development of Billing Determinants**

## Development of Pro Forma Revenue

Per Books Data

**Actual Base Revenue before Therm billing correction**

| | Actual Revenue | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 53,060 | 48,429 | 50,106 | 52,010 | 52,129 | 63,814 | 67,771 | 68,056 | 70,489 | 59,095 | 57,053 | 52,341 | 694,353 |
| 2 | R-3 | 983,185 | 905,358 | 947,147 | 1,066,376 | 1,496,266 | 2,232,229 | 2,665,012 | 3,050,163 | 2,915,620 | 2,140,139 | 1,443,843 | 1,062,203 | 20,907,541 |
| 3 | R-4 | 38,884 | 30,569 | 31,414 | 33,435 | 19,590 | 39,069 | 62,831 | 81,834 | 107,198 | 101,545 | 67,589 | 31,285 | 645,241 |
| 4 | Total Residential | 1,075,129 | 984,355 | 1,028,667 | 1,151,820 | 1,567,985 | 2,335,113 | 2,795,614 | 3,200,053 | 3,093,307 | 2,300,779 | 1,568,485 | 1,145,829 | 22,247,136 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 248,679 | 210,732 | 238,027 | 260,632 | 415,159 | 628,614 | 840,651 | 1,070,048 | 1,055,488 | 693,725 | 445,919 | 283,422 | 6,411,096 |
| 7 | G-42 | 242,851 | 222,685 | 283,827 | 335,142 | 525,103 | 773,239 | 1,023,435 | 1,193,344 | 1,232,586 | 865,714 | 531,909 | 322,469 | 7,552,302 |
| 8 | G-43 | 23,108 | 26,714 | 27,087 | 39,871 | 58,451 | 107,033 | 112,457 | 149,667 | 142,151 | 152,796 | 11,584 | 26,253 | 877,170 |
| 9 | G-51 | 74,761 | 72,895 | 70,337 | 77,487 | 81,081 | 99,698 | 115,716 | 131,260 | 132,932 | 103,243 | 89,613 | 79,855 | 1,128,877 |
| 10 | G-52 | 68,839 | 60,249 | 61,477 | 66,351 | 73,500 | 109,566 | 121,700 | 128,905 | 133,475 | 103,699 | 84,805 | 65,796 | 1,078,360 |
| 11 | G-53 | 28,474 | 49,935 | 41,618 | 68,557 | 51,799 | 103,491 | 121,093 | 126,374 | 117,239 | 99,264 | 90,082 | 39,098 | 937,022 |
| 12 | G-54 | 1,328 | 432 | 968 | 1,251 | 1,420 | 1,234 | 3,107 | 2,366 | 1,927 | 2,221 | 2,058 | 575 | 18,887 |
| 13 | G-63 | 29,189 | 33,421 | 26,444 | 27,871 | 29,280 | 31,525 | 28,189 | 37,588 | 29,128 | 26,257 | 48,928 | 24,517 | 372,337 |
| 14 | Total C/I | 717,228 | 677,063 | 749,783 | 897,160 | 1,235,793 | 1,854,399 | 2,366,348 | 2,839,552 | 2,844,925 | 2,046,916 | 1,304,897 | 841,985 | 18,376,050 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 1,792,357 | 1,661,419 | 1,778,450 | 2,048,980 | 2,803,778 | 4,189,511 | 5,161,962 | 6,039,605 | 5,938,231 | 4,347,695 | 2,873,382 | 1,987,814 | 40,623,185 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportatio | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 1,792,357 | 1,661,419 | 1,778,450 | 2,048,980 | 2,803,778 | 4,189,511 | 5,161,962 | 6,039,605 | 5,938,231 | 4,347,695 | 2,873,382 | 1,987,814 | 40,623,185 |

EnergyNorth Natural Gas Inc.
Test Year July 2006 - June 2007
Development of Billing Determinants

Development of Pro Forma Revenue

Attachment AEL-2
National Grid NH
DG 08-009
Page 5 of 8

Per Books Data

**Therm Billing Correction**

| | Actual Revenue | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | (291) | (238) | (268) | (291) | (341) | (466) | (529) | 0 | 0 | 0 | 0 | 0 | (2,424) |
| 2 | R-3 | (5,750) | (4,971) | (5,630) | (6,331) | (11,600) | (22,922) | (25,249) | 0 | 0 | 0 | 0 | 0 | (82,453) |
| 3 | R-4 | (252) | (168) | (188) | (194) | (130) | (338) | (586) | 0 | 0 | 0 | 0 | 0 | (1,857) |
| 4 | Total Residential | (6,294) | (5,377) | (6,085) | (6,816) | (12,070) | (23,726) | (26,365) | 0 | 0 | 0 | 0 | 0 | (86,734) |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | (1,135) | (589) | (1,121) | (1,778) | (3,878) | (6,791) | (10,121) | 0 | 0 | 0 | 0 | 0 | (25,414) |
| 7 | G-42 | (2,406) | (2,067) | (2,654) | (3,628) | (6,389) | (9,752) | (13,430) | 0 | 0 | 0 | 0 | 0 | (40,326) |
| 8 | G-43 | (226) | (189) | (203) | (263) | (647) | (1,370) | (1,853) | 0 | 0 | 0 | 0 | 0 | (4,750) |
| 9 | G-51 | (686) | (666) | (649) | (719) | (784) | (1,004) | (1,247) | 0 | 0 | 0 | 0 | 0 | (5,756) |
| 10 | G-52 | (806) | (679) | (710) | (642) | (685) | (1,287) | (1,478) | 0 | 0 | 0 | 0 | 0 | (6,287) |
| 11 | G-53 | (371) | (572) | (424) | (780) | (693) | (1,455) | (1,680) | 0 | 0 | 0 | 0 | 0 | (5,975) |
| 12 | G-54 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | G-63 | (442) | (435) | (455) | (370) | (404) | (492) | (538) | 0 | 0 | 0 | 0 | 0 | (3,137) |
| 14 | Total C/I | (6,072) | (5,197) | (6,217) | (8,181) | (13,480) | (22,152) | (30,346) | 0 | 0 | 0 | 0 | 0 | (91,645) |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | (12,366) | (10,575) | (12,302) | (14,997) | (25,550) | (45,878) | (56,711) | 0 | 0 | 0 | 0 | 0 | (178,379) |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportatio | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | (12,366) | (10,575) | (12,302) | (14,997) | (25,550) | (45,878) | (56,711) | 0 | 0 | 0 | 0 | 0 | (178,379) |

Development of Pro Forma Revenue

EnergyNorth Natural Gas Inc
Test Year July 2006 - June 2007
Development of Billing Determinants

Attachment AEL-2
National Grid NH
DG 08-009
Page 6 of 8

Per Books Data

**Base Revenue (without Gas Cost, Environmental or DSM surcharge revenue)**

| | Actual Revenue | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 52,769 | 48,191 | 49,838 | 51,719 | 51,788 | 63,348 | 67,242 | 68,056 | 70,489 | 59,095 | 57,053 | 52,341 | 691,929 |
| 2 | R-3 | 977,435 | 900,386 | 941,518 | 1,060,045 | 1,484,666 | 2,209,307 | 2,639,763 | 3,050,163 | 2,915,620 | 2,140,139 | 1,443,843 | 1,062,203 | 20,825,088 |
| 3 | R-4 | 38,631 | 30,401 | 31,227 | 33,240 | 19,461 | 38,731 | 62,244 | 81,834 | 107,198 | 101,545 | 67,589 | 31,285 | 643,384 |
| 4 | Total Residential | 1,068,835 | 978,978 | 1,022,582 | 1,145,003 | 1,555,915 | 2,311,387 | 2,769,249 | 3,200,053 | 3,093,307 | 2,300,779 | 1,568,485 | 1,145,829 | 22,160,401 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 247,544 | 210,143 | 236,906 | 278,854 | 411,280 | 621,823 | 830,530 | 1,070,048 | 1,055,488 | 693,725 | 445,919 | 283,422 | 6,385,682 |
| 7 | G-42 | 240,445 | 220,618 | 281,172 | 331,514 | 518,714 | 763,486 | 1,010,005 | 1,193,344 | 1,232,586 | 865,714 | 531,909 | 322,469 | 7,511,976 |
| 8 | G-43 | 22,882 | 26,524 | 26,883 | 39,608 | 57,804 | 105,663 | 110,604 | 149,667 | 142,151 | 152,796 | 11,584 | 26,253 | 872,419 |
| 9 | G-51 | 74,075 | 72,229 | 69,688 | 76,769 | 80,297 | 98,694 | 114,469 | 131,260 | 132,932 | 103,243 | 89,613 | 79,855 | 1,123,121 |
| 10 | G-52 | 68,033 | 59,570 | 60,767 | 65,709 | 72,816 | 108,279 | 120,222 | 128,905 | 133,475 | 103,699 | 84,805 | 65,796 | 1,072,073 |
| 11 | G-53 | 28,103 | 49,363 | 41,194 | 67,776 | 51,106 | 102,036 | 119,413 | 126,374 | 117,239 | 99,264 | 90,082 | 39,098 | 931,047 |
| 12 | G-54 | 1,328 | 432 | 968 | 1,251 | 1,420 | 1,234 | 3,107 | 2,366 | 1,927 | 2,221 | 2,058 | 575 | 18,887 |
| 13 | G-63 | 28,747 | 32,986 | 25,988 | 27,500 | 28,876 | 31,033 | 27,652 | 37,588 | 29,128 | 26,257 | 48,928 | 24,517 | 369,199 |
| 14 | Total C/I | 711,156 | 671,866 | 743,566 | 888,980 | 1,222,313 | 1,832,247 | 2,336,002 | 2,839,552 | 2,844,925 | 2,046,916 | 1,304,897 | 841,985 | 18,284,405 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 1,779,991 | 1,650,844 | 1,766,148 | 2,033,983 | 2,778,228 | 4,143,633 | 5,105,251 | 6,039,605 | 5,938,231 | 4,347,695 | 2,873,382 | 1,987,814 | 40,444,806 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportatio | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 1,779,991 | 1,650,844 | 1,766,148 | 2,033,983 | 2,778,228 | 4,143,633 | 5,105,251 | 6,039,605 | 5,938,231 | 4,347,695 | 2,873,382 | 1,987,814 | 40,444,806 |

Adjustments to Per Books Data

**Weather Normalization Adjustments to Net Revenue**

| | Gas Cost Adjustments | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | R-3 | 0 | 0 | 3,534 | 14,694 | 237,443 | 243,735 | 169,783 | (132,410) | (33,881) | (94,128) | 29,122 | 2,223 | 440,116 |
| 3 | R-4 | 0 | 0 | 67 | 172 | 3,505 | 4,786 | 3,956 | (3,935) | (1,419) | (4,905) | 1,321 | 124 | 3,671 |
| 4 | Total Residential | 0 | 0 | 3,600 | 14,866 | 240,949 | 248,521 | 173,739 | (136,345) | (35,300) | (99,033) | 30,443 | 2,347 | 443,787 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 0 | 0 | 2,137 | 5,884 | 57,934 | 110,481 | 82,526 | (67,222) | (17,898) | (27,511) | 15,820 | 1,946 | 164,298 |
| 7 | G-42 | 0 | 0 | 2,876 | 8,929 | 79,025 | 140,669 | 98,035 | (79,055) | (22,107) | (37,381) | 20,561 | 1,302 | 212,854 |
| 8 | G-43 | 0 | 0 | 112 | 580 | 8,988 | 17,152 | 12,081 | (10,123) | (3,842) | (4,424) | 514 | 401 | 21,439 |
| 9 | G-51 | 0 | 0 | 73 | 646 | 4,373 | 8,080 | 5,972 | (5,259) | (1,251) | (2,593) | 1,023 | 0 | 11,065 |
| 10 | G-52 | 0 | 0 | 72 | 454 | 4,678 | 8,774 | 5,433 | (4,797) | (1,053) | (2,515) | 412 | 115 | 11,574 |
| 11 | G-53 | 0 | 0 | 279 | 785 | 4,764 | 8,332 | 5,947 | (4,723) | (1,518) | (3,806) | 796 | 0 | 10,857 |
| 12 | G-54 | 0 | 0 | 2 | 24 | 0 | 0 | 0 | (60) | (21) | (69) | 40 | 9 | (75) |
| 13 | G-63 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total C/I | 0 | 0 | 5,551 | 17,302 | 159,764 | 293,489 | 209,995 | (171,238) | (47,490) | (78,299) | 39,166 | 3,772 | 432,011 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 0 | 0 | 9,151 | 32,168 | 400,713 | 542,009 | 383,734 | (307,583) | (82,791) | (177,333) | 69,609 | 6,119 | 875,796 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportatio | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 0 | 0 | 9,151 | 32,168 | 400,713 | 542,009 | 383,734 | (307,583) | (82,791) | (177,333) | 69,609 | 6,119 | 875,798 |

Adjusted Billing Determinants

Weather Normalized Net Revenue

| | Normalized Gas Costs | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | R-1 | 52,769 | 48,191 | 49,838 | 51,719 | 51,788 | 63,348 | 67,242 | 68,056 | 70,489 | 59,095 | 57,053 | 52,341 | 691,929 |
| 2 | R-3 | 977,435 | 900,386 | 945,051 | 1,074,738 | 1,722,110 | 2,453,043 | 2,809,546 | 2,917,753 | 2,881,740 | 2,046,011 | 1,472,965 | 1,064,426 | 21,265,204 |
| 3 | R-4 | 38,631 | 30,401 | 31,293 | 33,413 | 22,966 | 43,517 | 66,200 | 77,899 | 105,778 | 96,639 | 68,909 | 31,409 | 647,055 |
| 4 | Total Residential | 1,068,835 | 978,978 | 1,026,182 | 1,159,869 | 1,796,864 | 2,559,908 | 2,942,988 | 3,063,708 | 3,058,006 | 2,201,746 | 1,598,928 | 1,148,176 | 22,604,188 |
| 5 | | | | | | | | | | | | | | |
| 6 | G-41 | 247,544 | 210,143 | 239,043 | 284,737 | 469,215 | 732,304 | 913,056 | 1,002,827 | 1,037,790 | 666,213 | 461,739 | 285,368 | 6,549,980 |
| 7 | G-42 | 240,445 | 220,618 | 284,048 | 340,442 | 597,740 | 904,155 | 1,108,041 | 1,114,289 | 1,210,479 | 828,332 | 552,470 | 323,771 | 7,724,830 |
| 8 | G-43 | 22,882 | 26,524 | 26,995 | 40,186 | 66,792 | 122,815 | 122,685 | 139,544 | 138,309 | 148,372 | 12,098 | 26,654 | 893,858 |
| 9 | G-51 | 74,075 | 72,229 | 69,761 | 77,415 | 84,670 | 106,774 | 120,441 | 126,001 | 131,681 | 100,650 | 90,636 | 79,855 | 1,134,187 |
| 10 | G-52 | 68,033 | 59,570 | 60,839 | 66,162 | 77,494 | 117,053 | 125,655 | 124,108 | 132,422 | 101,183 | 85,217 | 65,911 | 1,083,647 |
| 11 | G-53 | 28,103 | 49,363 | 41,473 | 68,562 | 55,870 | 110,368 | 125,360 | 121,651 | 115,721 | 95,457 | 90,877 | 39,098 | 941,903 |
| 12 | G-54 | 1,328 | 432 | 970 | 1,275 | 1,420 | 1,234 | 3,107 | 2,306 | 1,906 | 2,152 | 2,097 | 584 | 18,812 |
| 13 | G-63 | 28,747 | 32,966 | 25,988 | 27,500 | 28,876 | 31,033 | 27,652 | 37,588 | 29,128 | 26,257 | 48,928 | 24,517 | 369,199 |
| 14 | Total C/I | 711,156 | 671,866 | 749,117 | 906,281 | 1,382,077 | 2,125,735 | 2,545,997 | 2,668,314 | 2,797,434 | 1,968,617 | 1,344,063 | 845,757 | 18,716,416 |
| 15 | | | | | | | | | | | | | | |
| 16 | Total Firm Sales | 1,779,991 | 1,650,844 | 1,775,299 | 2,066,151 | 3,178,941 | 4,685,643 | 5,488,985 | 5,732,022 | 5,855,441 | 4,170,363 | 2,942,991 | 1,993,934 | 41,320,604 |
| 17 | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | |
| 19 | 280 Day Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | | | | | | | | | | | | | | |
| 21 | Interruptible Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | | | | | | | | | | | | | | |
| 23 | Non-firm Transportatio | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | | | | | | | | | | | | | | |
| 25 | Total | 1,779,991 | 1,650,844 | 1,775,299 | 2,066,151 | 3,178,941 | 4,685,643 | 5,488,985 | 5,732,022 | 5,855,441 | 4,170,363 | 2,942,991 | 1,993,934 | 41,320,604 |

# STATE OF NEW HAMPSHIRE
# BEFORE THE
# PUBLIC UTILITIES COMMISSION

ORIGINAL
Case No. DG 08-009
Exhibit No. #14

**EnergyNorth Natural Gas, Inc.**
**d/b/a National Grid NH**

**Docket DG 08-009**

**Direct Testimony**
**of**
**Gary Bennett**

**February 25, 2008**

## I. Introduction

**Q. Please state your name and business address.**

A. My name is Gary Bennett. My business address is 52 Second Ave, Waltham, MA

**Q. By whom are you employed and in what capacity?**

A. I am the Director Customer Meter Services, New England North, for National Grid USA, with responsibility for Gas and Electric metering services in Northern New England. Metering services includes the field operations of emergency response, metering work and field collections. My responsibilities include the territory served by EnergyNorth Natural Gas, Inc. d/b/a National Grid NH (the "Company" or "National Grid NH").

**Q. Please briefly describe your educational background and your professional experience.**

A. I graduated from Massachusetts Maritime Academy in 1982 with a B.S. in Engineering. In 1988, I received an M.B.A. from Rensselaer Polytechnic Institute. I began my career with General Dynamics Electric Boat division as a Nuclear Test Engineer, after which I joined LTXX Corporation in 1998 as a Manufacturing Engineer. In 1991, I joined Boston Gas Company as Customer Service Coordinator, then became Service Dispatch Supervisor, followed by Distribution Field Coordinator. In 1997, I was one of seven core team members involved in the startup of ServicEdge (now KeySpan Home Energy Services (KHES), an unregulated subsidiary of KeySpan Corporation that provides HVAC services). At KHES, I was named Director of Human Resources and Support

Services, including the Customer Call Center and Billing departments. Following the KeySpan acquisition of Eastern Enterprises, in 2001 I returned to the regulated side of the business with KeySpan Corporate Services. I held the position of Director of Customer Relations, New England, with responsibility for Accounts Processing and the Customer Call Center. In October 2007, I was named to my current position

**Q. Are you a member of any professional organizations?**

A. I am a member of the Northeast Gas Association.

**Q. Have you previously testified before this Commission or any other regulatory agency?**

A. No, I have not.

**Q. What is the purpose of your testimony?**

A. I will provide an overview of the changes that National Grid NH is proposing to make to its collections process and the costs and anticipated benefits of implementing those changes.

**Q. Why is the Company presenting those changes in this proceeding?**

A. In Docket DG 07-050, the Commission staff ("Staff") expressed concern regarding whether the Company's collections efforts were sufficiently rigorous. In particular, the Staff pointed to the bad debt ratio for Northern Utilities in New Hampshire and noted that it was substantially lower than that of the Company. The Company believed then, as it does now, that there are many appropriate reasons that its uncollectible expense, and therefore its bad debt ratio, has historically been and remains higher than that of Northern. However, as the Company made clear when it reached agreement with Staff and the Office of Consumer Advocate ("OCA") on most of the issues in that proceeding, the Company would prefer to work constructively with Staff and the OCA on these issues, to the mutual benefit of customers and the Company. As a result, the Company agreed to submit to Staff a proposal for changes to its collections process, and the Staff and OCA agreed that the prudently incurred incremental costs of that process would be included in this rate case on an annualized basis. Specifically, the settlement provided:

> The Company will file a written plan setting forth its proposed collections process on a going-forward basis for review by Staff. The plan will be filed no later than with the Company's upcoming base rate case filing. The prudently incurred costs of the collections process described in the plan (including, on an annualized basis, any costs that are incremental to those in the Company's test year) shall be recoverable through rates set in the base rate case....

**Q. Has the settlement in DG 07-050 been approved by the Commission?**

A. Not as of the date of the filing of this testimony. The resolution of that docket has been delayed by an issue that is unrelated to the collections process. Because the Company feels it is important to demonstrate its commitment to the terms of the settlement, it is proceeding in accordance with the terms of that agreement, notwithstanding the fact that the case is still pending before the Commission.

**Q. Has the Company developed a proposal for modifications to its collections process, as contemplated by the settlement agreement in DG 07-050?**

A. Yes. That proposal is included with my testimony as Attachment GB-1.

**Q. Please provide an overview of the Company's plan for modifying its collections process.**

A. The cornerstone of the proposal is a plan to substantially increase the number of field visits to customers. Ideally, every account that has arrears of sixty days or more will receive a field visit under the proposal. If the initial visit does not resolve the account issue, an additional visit would then be performed.

**Q. What impact will such a procedure have on the number of field visits?**

A. During the past twelve months, the peak number of customers whose accounts were in arrears for sixty days or more was 7,250. During the same period, the Company made 6,600 visits to customers with arrears, 29% of which were effective, meaning that they resulted in a payment or a collection lock. In order to make an initial visit to every account in sixty days arrears status plus one additional visit for those accounts where the initial visit is not effective, 12,398 visits (i.e., almost double the current level) would be required.

**Q. What costs are associated with performing the additional field visits?**

A. The incremental cost of performing the additional field visits would be $644,078, which reflects the cost of adding two collections technicians who can handle twenty-three jobs per day during the collections season (April 15 through November 15) plus one technician to work the subsequent 1,398 reconnects at a rate of six jobs per day (which assumes that 95% of customers who are turned off will eventually be turned back on). There are also substantial additional costs related to the Company's call center and a number of lesser costs, all of which are detailed in Attachment GB-1.

**Q. Will the Company's plan reduce the level of uncollectible expense it has experienced?**

A. Over the long run, the Company is confident that the more intensive collections efforts will have a beneficial impact. However, initially the additional collections activity is likely to increase the level of uncollectible accounts. It is impossible to predict exactly how much the uncollectible account expense will increase at first or how long that increase is likely to last. In addition, the level of uncollectible accounts is influenced significantly by the level of gas costs, something that is outside the Company's control.

**Q. Has the increased cost of the Company's collections process proposal been included in the costs that the Company is proposing to include in rates in this case?**

A. Yes. However, the amount that was included was only $442,458, which was based on a preliminary estimate that was available at the time that the Company was preparing the financial schedules for this case. The actual amount will need to be included once the collections plan has been finalized through discussions with Staff and the OCA.

**Q. Are you saying that the Company's plan is still not final?**

A. The Company is prepared to proceed with implementation of the plan. However, it has committed to meet with Staff to discuss its proposal, and it plans to do that as soon as possible. Once Staff has had an opportunity to comment on the plan, the Company will be able to provide the final costs associated with its implementation. The Company's goal is to achieve the most cost-effective collections process in light of applicable regulatory constraints and policy considerations.

**Q. Does that conclude your testimony?**

A. Yes.

**National Grid NH**
**2008 Collections Plan**
**February 25, 2008**

## I. Background

On April 10, 2007 the Commission opened Docket DG 07-050 to review a number of issues, one of which was whether the Company's bad debt allowance was reasonable. During the course of the proceeding, the Company responded to numerous data requests regarding the Company's collection practices and their effectiveness in controlling the Company's uncollectible accounts expense, and therefore its bad debt ratio. Subsequently, on November 11, 2007, the Company the PUC Staff and the Office of Consumer Advocate entered into a partial settlement, which included the following provision related to the Company's bad debt allowance:[1]

> The Company will file a written plan setting forth its proposed collections process on a going-forward basis for review by Staff. The plan will be filed no later than with the Company's upcoming base rate case filing. The prudently incurred costs of the collections process described in the plan (including, on an annualized basis, any costs that are incremental to those in the Company's test year) shall be recoverable through rates set in the base rate case.

As discussed below, the Company has reviewed its collection processes and determined that an increase in field collection activity would have a positive impact on the percentage of write offs incurred by the Company.

[1] The Commission has not yet ruled on the partial settlement or the contested matters under review in the docket.

## II. Timeline of Collection Activity

As an initial matter, the Company reviewed its time line of collection activities for accounts that are not protected from termination by PUC rules. The table below represents the current timeline of collections activities performed by National Grid NH.

| Customer In Good Standing[2] | | Customer Not In Good Standing | |
|---|---|---|---|
| Day 1 | Create Bill | Day 1 | Create Bill |
| Day 31 | Late Charge Applied<br>Reminder Notice<br>Outbound Calls | Day 31 | Late Charge Applied<br>Reminder Notice<br>Outbound Calls |
| Day 61 | Late Charge Applied<br>Reminder<br>Outbound Calls | Day 61 | Late Charge Applied<br>Shutoff Notice (Summer)<br>Reminder Notice (Winter)<br>Outbound Calls |
| Day 91 | Late Charge Applied<br>Shutoff Notice<br>(Summer)Reminder<br>Notice (Winter)<br>Outbound Calls | Day 68 | Disconnect Notice<br>Mailed Separately<br>Outbound Calls |
| Day 98 | Disconnection Notice<br>Mailed Separately<br>Outbound Calls | Day 81 | Create Field job to<br>disconnect<br>service |
| Day 112 | Create Field job to<br>Disconnect service | | |

The Company refrains from disconnecting residential heating accounts in the winter period due to concerns for the health and safety of its customers and to avoid the possibility of freeze up damages to unheated homes.

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[2] A customer in good standing is a customer who has a proven track record of paying KeySpan over a period of time. Based on that, the Company allows the customer, as a "low risk" customer, an additional 30 days before disconnect action

## III. Field Activity

During 2007, the Company performed 6,600 field visits. 1, 902 (29%) of these visits were considered effective, as they resulted in either a payment or collection lock. The remaining 4,698 (71%) visits were recorded as can not get in ("CGI"). A review of the year end data shows that there were a total of 7,250 customers with collectible arrears greater than 60 days past due and eligible for a field visit. The table below indicates how these accounts are broken out between residential and non-residential.

| | Residential | Non-Residential | Total |
|---|---|---|---|
| Peak Customers>60 Days | 6,800 | 450 | 7,250 |
| Annual Field Visits | 5,700 | 900 | 6,600 |
| Effectiveness Rate | 28% | 34% | 29% |
| Effective Visits | 1,596 | 306 | 1,902 |
| | | | |
| Accounts without Effective Visit | 4,104 | 594 | 4,698 |
| Accounts Not Visited | 1,100 | 0 | 1,100 |
| Total Incremental Required Visits | 5,204 | 594 | 5,798 |

For the Company to schedule and perform field visits to the eligible customers who did not receive an initial field collection visit following a disconnect notice as well as to perform an additional follow up field visit to CGI accounts, the Company would need to add resources for an additional 5,798 field visits. The field cost to conduct 5,798 incremental field visits with the subsequent reconnect is $539,053. The cost is based on two collections technicians working 23 jobs/day during the collections season (April 15 through November 15) plus one technician to work the subsequent 1,398 reconnects at six jobs per day (this assumes 95% of customers turned off will eventually be turned back on).

The total incremental cost of adding these resources plus the contact center costs would be $644,078 as shown below:

| | | |
|---|---|---|
| **Field Costs for Visits and Reconnects** | | |
| Total Incremental Jobs | 5,798 | |
| Incremental Field Collection Employee Labor | $112,764 | |
| Incremental Field Collection Employee Labor Burdens | $230,873 | |
| Non-Labor Costs | $37,499 | |
| Total Incremental Field Collection Costs | $381,136 | |
| Total Turn Ons | 1,398 | |
| Incremental "Reconnect" Field Employee Labor | $59,504 | |
| Incremental "Reconnect" Field Employee Labor Burden | $60,914 | |
| Non-Labor Costs | $37,499 | |
| Total Incremental Field "Reconnect" Costs | $157,917 | |
| Total Field Collections Cost | $539,053 | |
| **Contact Center Costs for Accounts Terminated** | | |
| Call Center Costs | | |
| Number of Locks | | 1,472 |
| Calls per Lock | | 3.0 |
| Total Calls | | 4,416 |
| Cost per Call | | $7.70 |
| Sub - Total Call Center Cost | | $34,000 |
| **Contact Center Costs for Accounts Noticed but not Terminated** | | |
| Incremental Visits | | 5,798 |
| Required Increase in Term Notices | | 11,596 |
| Resolution Rate for Term Notices | | 50% |
| Incremental Accounts Resolved | | 5,798 |
| Calls Per Account Resolved | | 1.5 |
| Incremental Calls to Resolve Accounts | | 8,697 |
| Cost per Call | | $7.70 |
| Sub - Total Call Center Cost | | $66,967 |
| Total Call Center Cost | | $100,966 |
| Cost of Sending Incremental Notices | | |
| Incremental Notices | | 11,596 |
| Cost per Notice | | $0.35 |
| Total Noticing Cost (Facilities) | | $4,059 |
| **Grand Total Cost** | | **$644,078** |

This significant increase in field collections is expected to yield net savings in uncollectible account expense over the long run. However, uncollectible accounts are expected to increase in the short run as more accounts are visited and some are locked off and do not restore service. The long run benefits are not subject to precise calculation until sufficient data regarding the effectiveness rates of these incremental field visits can be gathered and analyzed. Accordingly, the Company is prepared to implement this plan, subject to further discussion with Commission Staff and the OCA as contemplated by the settlement agreement in Docket DG 07-050 and to meet with Staff and the OCA periodically to monitor the plan's progress.

# STATE OF NEW HAMPSHIRE
# BEFORE THE
# PUBLIC UTILITIES COMMISSION



**EnergyNorth Natural Gas, Inc.**
**d/b/a National Grid NH**

**Docket DG 08-009**

**Direct Testimony**
**of**
**Gary L. Goble**
**Regarding Lead-Lag Study**

**February 25, 2008**

Prepared by:

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## LIST OF ATTACHMENTS

## I. POSITION AND QUALIFICATIONS

**Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.**

A. My name is Gary L. Goble. I am a managing consultant with the firm of Management Applications Consulting, Inc. ("MAC"). MAC's headquarters is 1103 Rocky Drive, Suite 201, Reading, Pennsylvania 19609. My business office is 2218 Equestrian Trail, Austin, Texas 78727.

**Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.**

A. I am a consultant with 34 years of experience in regulatory matters. I have an undergraduate degree (BSPA) from the University of Arkansas at Fayetteville, Arkansas, and a graduate degree (MBA) from St. Edward's University in Austin, Texas. I have worked as a staff analyst for two regulatory commissions and as a consultant to natural gas utilities, electric utilities, municipalities, electric cooperatives, and industrial consumers. I have testified before state and local regulatory agencies and boards on numerous occasions. The primary focus of my work experience has been in the areas of cost analysis, pricing, and economic and financial analysis. A more detailed list of my qualifications and experience is provided in Attachment GLG-LL-1.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A. I have been retained by and am testifying on behalf of EnergyNorth Natural Gas, Inc. d/b/a National Grid NH ("National Grid NH" or "the Company").

## II. PURPOSE OF TESTIMONY

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to present and sponsor the cash working capital ("CWC") requirements of National Grid NH. CWC is a component of rate base upon which investors are entitled to earn a fair rate of return. In order to quantify the CWC requirements, I prepared a lead-lag study that develops and documents National Grid's cash flow patterns in accordance with generally accepted practices.

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. My testimony consists of four sections. Section I introduces my background information. Section II describes the purpose and organization of my testimony. Section III presents the lead-lag study I prepared on behalf of National Grid NH to determine the per-books CWC. A summary schedule detailing the lead and lag days by revenue and cost component for the test year on a per books basis is provided as Attachment GLG-LL-2. Finally, Section IV of my direct testimony summarizes my conclusions and recommendations.

## III. CASH WORKING CAPITAL

### 1. Definition of CWC

**Q. PLEASE DEFINE CASH WORKING CAPITAL.**

A. CWC is the amount of investor-supplied capital required to fund the day-to-day operations of a company after accounting for the timing differences between booked and actual revenues and expenses. CWC represents amounts funded by investors to provide service prior to payment for such service by customers. As such, CWC is typically an addition to a company's rate base.

**Q. DID YOU PERFORM A STUDY TO ESTIMATE THE CWC OF NATIONAL GRID NH FOR THE ADJUSTED TEST YEAR?**

A. Yes. Attachment GLG-LL-2 presents the results of the lead-lag study conducted for National Grid NH using the per books revenue requirements for the test year ending June 30, 2007. As shown on this attachment, the Company's rate base addition for CWC related to purchased gas expense is $4,464,340. Work on computing the non-gas cash working capital has not yet been completed, but should be finalized in the near future. I will submit that information in a separate filing as soon as possible. However, I have included in this testimony a description of the methodology for that aspect of my lead-lag study, so that my supplemental testimony will be limited to providing the results of that process.

**Q. WHAT IS A LEAD-LAG STUDY?**

A. A lead-lag study is an analysis designed to determine the funding required to operate a company on a day-to-day basis. A lead-lag study compares (1) the timing difference between the receipt of service by customers and their subsequent payment for these services and (2) the timing difference between the incurrence of costs by National Grid NH and its subsequent payment of these costs. Therefore, a lead-lag study must compute both a revenue lag (or lead) and an expense lead (or lag). Attachment GLG-LL-2, page 1 of 3, summarizes the lead lag study results for National Grid NH. The CWC was developed using systematic reviews of all cash flows for National Grid NH's revenues and operations expenses. The lead-lag study measured the CWC provided by National Grid NH's day-to-day natural gas operations for the 12-month period ending June 30, 2007. The CWC was measured separately for purchased gas and for those costs that comprise the base revenue requirement.

**Q. PLEASE DEFINE THE TERMS "LAG DAYS" AND "LEAD DAYS" AS USED IN YOUR TESTIMONY.**

A. Revenue lag days are the number of days between delivery of service to National Grid NH's customers and the subsequent receipt by the Company of payment for the service (revenue lag). Expense lag days are the number of days between the receipt of goods or services provided to National Grid NH by vendors and the payment by the Company for those goods and services.

Because National Grid NH's customers receive service prior to paying for it, the Company experiences a revenue lag in its daily operations. This revenue lag is computed based upon a study of the time lag between the date when customers receive service and the date when the customers pay for such service. The longer the revenue lag, the greater the length of time that investor capital is employed to fund the Company's day-to-day operations. The revenue lag of National Grid NH is 50.98 days, as developed on Attachment GLG-LL-2, page 2 of 3.

Generally, expenses are paid by National Grid NH after vendors have provided their goods or services, which results in an expense lag. On occasion, National Grid NH pays for services before they are provided. For example, rents are typically paid in advance of the rental period. In these instances, the expenses lead their service period. Rather than keeping track of both lead and lag days, this study employs only lag days as a matter of convention. The expense lag is calculated as the number of days between the date when National Grid NH receives goods or services from a vendor and the date when the Company pays for such goods or services. If the expenses are paid before the services are provided, then the expense lag is expressed as a negative amount. Consequently, any increase in the number of expense lag days results in a reduction of the amount of working capital required for ongoing National Grid NH operations. The number of lag days for purchased gas expense is -38.94 days, as shown on Attachment GLG-LL-2, page 3 of 3. Note that as a matter of convention, I will generally refer to lead days as lag days with a negative sign (i.e., gas purchases lead the payment for this service, so there is a negative number of "lag" days).

The arithmetic difference between the computed revenue lag and the computed expense lag is the number of days that stockholders must provide funding for the utility's daily operations. As shown on Attachment GLG-LL-2, page 1 of 3, line 47, the Company's revenues lag the recovery of purchased gas costs by 12.04 days.

## 2. <u>Lead-Lag Study General Approach</u>

**Q. PLEASE DESCRIBE THE APPROACH YOU USED IN PREPARING YOUR LEAD-LAG STUDY.**

I began the lead-lag study with the selection of the per-books revenues and expenses for the12-month period ended June 30, 2007 to form the basis for my analysis. I determined the lag days in the recovery of revenue by type of revenue (i.e., sales and other revenues). For operation and maintenance ("O&M") expenses, I developed lag days for each of several types of expenses (i.e., purchased gas, labor, employee pensions and benefits, uncollectible accounts, and other O&M expenses). In addition, I developed lag days for taxes, including property taxes, other taxes excluding property taxes, federal income tax, state income tax, and deferred taxes. Once the lag days for the test year are established on a per-books basis, they are applied to the test year pro forma revenue requirements. The lead or lag days for each of the items described above are then multiplied by the test year pro forma amounts to determine the dollar-days of CWC. The dollar-days of revenue less the dollar-days of expenses and taxes may then be divided by 365 days to obtain the average daily CWC.

### 3. <u>Methods of Computation</u>

**Q. PLEASE DESCRIBE YOUR CALCULATION OF REVENUE LAGS.**

A. The calculation of revenue lags is summarized on Attachment GLG-LL-2, page 2. As previously described, "revenue lag" is the length of time that occurs between the Company's provision of service to its customers and the subsequent receipt of payment for those services. The existence of a revenue lag makes it necessary for investors to provide the funding for the Company to pay its operating costs during the lag period.

The measurement of revenue lag days typically consists of four components: (1) service lag, (2) billing lag, (3) collection lag and (4) revenue float. Since the time periods for these four components are mutually exclusive, revenue lag is computed by adding together the total number of days associated with each of the four revenue lag components. This total number of lag days represents the amount of time between the recorded delivery of service to customers and the receipt of the related revenues from customers.

**Q. PLEASE DESCRIBE HOW YOU CALCULATE SERVICE LAG.**

A. The service lag is the average time span between the mid-point of the customer's consumption interval, also known as the usage period, and the time that such usage is recorded by the Company for billing purposes. This service period determines the average length of time over which the billed services are provided and establishes a common point in time from which to measure (1) the time of reimbursement for the billed services, and (2) the time at which the accrued costs for the service period are actually paid. For virtually all utilities, the service lag is one-half of an average month or 15.22 days.

**Q. PLEASE DESCRIBE YOUR CALCULATION OF BILLING LAG.**

A. The billing lag is the time required to process and send out customer bills. The billing lag begins at the end of the service period when customer consumption is metered, and it ends when the bills are rendered and billings are posted to accounts receivable. The billing lag may be influenced by factors such as whether automated or manual meter reading systems are employed, the generation of invoices from metering data and other processes affecting the time to post billings to accounts receivable. National Grid NH utilizes an automated meter reading system and posts its meter reading daily for billing later the same night. As a result, weekends and holidays do not influence the Company's billing lag.

National Grid NH's billing lag was approximately one day, among the shortest billing lag periods MAC has observed.

**Q. PLEASE DESCRIBE YOUR CALCULATION OF COLLECTION LAG.**

A. The collection lag identifies the time delay between the issuance of customer bills and the receipt of the billed revenues. Collection lag begins with the posting of bills and ends with the receipt of payment. Collection lag may be influenced by payment arrangements, contract terms, postal delivery delays, customer inquiries, delinquent accounts, service termination practices, and other factors. As I will discuss later in my testimony, I have employed the accounts receivable turnover ratio method to determine the collection lag of slightly less than 35 days, as contemplated by the settlement in Docket DG 07-050.

**Q. PLEASE DESCRIBE THE FINAL COMPONENT OF REVENUE LAG, REVENUE FLOAT.**

A. Revenue float is the time difference between when funds are received from customers until customer payments clear the banks and are available to the Company. To clarify, there are two periods of float. The first is associated with the Company's payment of services from vendors. Expense float, or lag, is discussed later in my direct testimony. The second period of float is the delay in receipt of cash from customer payments. In this latter instance, National Grid NH's cash requirements are reduced by the delay in mailing and check processing. Many lead-lag studies assume that revenue float and check float are equal and offsetting and, therefore, can be removed. A closer examination reveals that the issue is much more complex. The majority of National Grid NH's larger payments are made by wire transfer with a much shorter lag than a conventional mailed check. On the revenue side, only a small portion of customer payments are made by cash, credit card or bank transfer. Again, these payments have smaller lag times to clear than conventional checks. Since the dollar volume of utility payments exceed their receipts made by cash, credit card and bank transfer, the inclusion of check float in the lead-lag study should slightly increase CWC requirements. I have chosen to avoid this level of complexity with the knowledge that our simplifying assumption will slightly understate CWC and will not disadvantage customers. The inclusion of float would logically cause a slight increase to total net lag and a commensurate increase in cash working capital requirements, albeit with a significant level of additional complexity to quantify the actual impact. Therefore, I have chosen not to quantify float for revenues or expenses in this study.

**Q. TURNING TO THE TIMING OF CASH FLOWS ASSOCIATED WITH EXPENSES, HOW DID YOU DETERMINE THE LAG ASSOCIATED WITH PURCHASED GAS EXPENSE?**

A. The calculation of expense lags is summarized on Attachment GLG-LL-2, page 3. Purchased gas expense, shown on line 2, is the largest category of expense and comprises over three-quarters of the Company's total revenue requirements. Each purchased gas invoice for the year was scrutinized in the preparation of this calculation. Consistent with general industry practice and without exception, each invoice represents billings for the prior calendar month. The service period for each monthly invoice is defined as the 24-hour period ending at 10:00 AM.

purchased gas expense is calculated as -38.94 days. Note that our calculations do not address gas placed in storage. The lead-lag study identifies the lag between receipt of gas and payment of invoices. The additional working capital required to support gas in fuel inventory after the payment of invoices is recognized through an addition to rate base and is outside of the lead-lag study. That is, the lead-lag study addresses the working capital requirements to the Company from the time gas is delivered until it is recorded in fuel inventory. After being recorded in fuel inventory, the fuel inventory amount is an addition to rate base and is, therefore, excluded from the lead-lag calculation.

**Q. WITH RESPECT TO YOUR SUPPLEMENTAL TESTIMONY THAT WILL ADDRESS THE LAG FOR COSTS OTHER THAN PURCHASED GAS, HOW IS THE LAG FOR LABOR EXPENSE DETERMINED?**

A. The majority of the Company's payroll stems from weekly or bi-weekly payroll disbursements. Using sample data, we measured the lag between the mid-point of the pay period and the pay date. However, not all labor costs earned by employees in the pay period are paid out as salary, the difference being payroll



Consequently, each invoice is for the period beginning at 10:00 AM day of the previous month and ending at the same time in the cu Payments are made on approximately the 25th of the following mont on weekend and holiday schedules. The column labeled "Lag Day lag between two mid-point of the service period and the payment date compute the average lag, the individual invoices were weighted b amount of the invoice. The weighted average of the lag from e

purchased gas expense is calculated as -38.94 days. Note that our ca not address gas placed in storage. The lead-lag study identifies the receipt of gas and payment of invoices. The additional working ca to support gas in fuel inventory after the payment of invoices i through an addition to rate base and is outside of the lead-lag study. lead-lag study addresses the working capital requirements to the Co the time gas is delivered until it is recorded in fuel inventory. recorded in fuel inventory, the fuel inventory amount is an additior and is, therefore, excluded from the lead-lag calculation.

Q. WITH RESPECT TO YOUR SUPPLEMENTAL TESTIMO WILL ADDRESS THE LAG FOR COSTS OTHER THAN PU GAS, HOW IS THE LAG FOR LABOR EXPENSE DETEPMIN

withholdings. In order to make an accurate calculation of total labor costs, we identified all labor-related costs and identified when the Company actually expended the cash. These labor-related costs include all salary including incentive compensation, payroll taxes including withholding taxes, and a wide range of benefits. Regular payroll costs are the largest component of labor costs and have the shortest payment lag. However, other components of labor costs have relatively long delays. For example, incentive compensation pay earned during the course of the year is paid in mid-March in the following year, resulting in a much longer expense lag. In addition to direct labor expense, we examined other labor-related costs to the Company, including payroll taxes and pension and benefits expense as will be discussed below.

**Q. PLEASE DESCRIBE HOW THE LAG IS CALCULATED FOR PENSIONS AND BENEFIT EXPENSE.**

A. The method for calculating pensions and benefit expense follows the same approach used for all other lag calculations. For each expense, the service period and its mid-point were determined. Then the payment date was established. The lag was then computed as the difference between the payment date and the mid-point of the service period. Next, a weighted average of each expense was computed to determine the overall average for this category.

**Q. ARE THERE OTHER O&M EXPENSES THAT WERE INCLUDED IN THE CALCULATION OF EXPENSE LAG?**

A. Yes, the Company provided a comprehensive list of all cash disbursements made during the year. In terms of total dollar expenditures, the majority of these expenses have already been identified and their lags computed. However, approximately $7 million of expenses were not accounted for in these calculations. These remaining expenses will be shown under the heading of "Other O&M" in Attachment GLG-LL-3, which will be included with my supplemental testimony. Because these expenses are made up of thousands of vouchers prepared throughout the course of the test year, it is a daunting task to examine each voucher, identify its service period and payment date, and calculate the expense lag. From a practical standpoint, statistical sampling is the only reasonable solution, and, therefore, that is the approach I have taken.

**Q. PLEASE DESCRIBE THE PROCESS FOR SAMPLING OF "OTHER O&M" EXPENSE.**

A. In order to develop an efficient sampling plan to study the remaining expenses, I used a stratified sequential sample to estimate the lag of this wide variety of expenses. In total, four strata totaling nearly 350 samples were drawn from the population of all test year vouchers. Based on a sample of this size relative to the size of the population, I can estimate the lag on the entire population of invoices to within plus or minus one percent at a 90 percent confidence level. Narrowing this bandwidth would require much larger samples without any reasonable expectation that the average lag would change. Considering the thousands of cash expenses incurred by National Grid NH in this general category of Other O&M Expenses, the sampling procedure provides a reasonable estimate for the expense lag for this category without the considerable and unnecessary burden of reviewing huge quantities of data.

**Q. HOW DID YOU DETERMINE THE LAG FOR THE ACCOUNTING ENTRIES APPEARING IN THE COMPANY'S REVENUE?**

A. Utility revenue requirements include a number of non-cash expenses or accrual accounting entries in addition to operating and maintenance expenses. These accounting entries recognize the accrual of expenses commensurate with the service rendered in the test period. The most notable items in this category are depreciation and amortization, uncollectible accounts expense, and provision for deferred income taxes. Since the timing and amount of these payments are established to coincide with their accounting liability, the expense occurs at the time service is rendered, and the net lag is zero days.

### 4. <u>Results of National Grid Lead-Lag Study</u>

**Q. WHERE HAVE YOU PRESENTED THE RESULTS OF THE CWC CALCULATIONS FOR THE PER-BOOKS TEST YEAR?**

A. The results of the lead-lag study are summarized on Attachment GLG-LL-2, page 1. This page summarizes the revenues from page 2 and the expenses from page 3 and presents the Company's CWC for test year purchased gas expense on a per-books basis. Several cells on pages 1 and 3 are currently blank, but will be provided with my supplemental testimony.

**Q. HAVE YOU IDENTIFIED THE NET LAG DAYS BETWEEN REVENUE AND EXPENSE FOR NATIONAL GRID NH FOR THE TWELVE MONTHS ENDING JUNE 30, 2007 ON A PER-BOOKS BASIS?**

A. Yes. As indicated by the data in Attachment GLG-LL-2, page 1, the net lag for National Grid NH's purchased gas expense as measured by the lead-lag study is 12.04 days. The positive lag indicates that the system requires stockholder capital to compensate for the fact that the lag in the recovery of revenues is greater than the lead (i.e., negative lag) in the payment of expenses. On a per-books basis, National Grid NH's CWC requirement for purchased gas expense for the June 30, 2007 test year is $4,464,340, as shown on Attachment GLG-LL-2. The results with regard to the Company's non-gas expenses will be provided in my supplemental testimony.

**Q. REFERRING TO ATTACHMENT GLG-LL-2, COULD YOU DISCUSS THE STRUCTURE OF YOUR PER-BOOKS LEAD-LAG STUDY SUMMARY?**

A. The summary of the National Grid NH lead-lag study consists of three sections. Lines 1 through 4 summarize the revenue lag. Lines 6 through 32 detail the expense lag data. Lines 34 to 55 show CWC in total and segregated between purchased gas and all other costs.

The calculations are based on the actual, per-books, costs. In a number of instances (for example, income taxes) the actual annual data is not indicative of the cash working capital requirements of the Company on an ongoing basis. For example, under normal conditions, the rates in effect are expected to allow the Company's stockholders to earn a reasonable return on their investment, and the utility must pay income taxes on this return. Therefore, the level of CWC computed on a per-books basis at the test year return understates the level of

CWC required for normal operations at the proposed return level because the CWC does not reflect the taxes that will have to be paid on the proposed increase in return. The importance of the per-books study is to determine the appropriate number of lag days applicable to revenue and expense items. The actual level of CWC will be derived as set forth in Attachment GLG-LL-3, which will be provided with my supplemental testimony. That calculation will use the lag days taken from Attachment GLG-LL-2 and apply the lags day for each identified revenue requirement cost component to the pro forma revenue requirement filed in this case.

In order to compute subtotals and totals, the rightmost working column, labeled "Day Weighted Amount," is also shown in Attachment GLG-LL-2. For those categories with known lag days, this column is the product of the annual expense and the lag days. For rows displaying subtotals and totals, this column will be computed and then used along with the appropriate figure from the Annual Expense column to compute the average lag. Row 32 of supplemental Attachment GLG-LL-3 will show the weighted average lag of all expenses.

**Q. PLEASE EXPLAIN THE CALCULATION OF CWC FOR PURCHASED GAS EXPENSES.**

A. Attachment GLG-LL 2, page 1, shows that revenues are received 50.98 days after the service is provided to customers (line 1), and purchased gas expenses are paid 38.94 days after service has been provided by vendors (line 7). Thus, there is a net lag of 12.04 days (50.98 revenue lag days - 38.94 expense lag days = 12.04 net lag days) for revenues less expenses, as shown on Row 47. Because the recovery of revenues lags the payment of expenses, investors must provide the funds to pay for the daily operations of the Company, and the CWC amount is a positive addition to rate base. The CWC required to support purchased gas expense is computed by multiplying the 12.04 days of lag, dividing by 365 and then multiplying by the purchased gas expense, as shown on line 49.

**Q. HOW WILL YOU COMPUTE THE CWC FOR THE COMPANY'S REVENUE REQUIREMENTS ON A PRO FORMA BASIS?**

A. In my supplemental testimony, I will present Attachment GLG-LL-3 to develop the CWC requirements for the pro forma test year revenue requirements. This attachment will be very similar to and will employ the same format as Attachment GLG-LL-2. However, Attachment GLG-LL-3 will take the individual lag days from Attachment GLG-LL-2 and apply these lag days on a line-by-line basis to the test year pro forma revenue requirements. The resulting CWC represents the capital that must be provided by stockholders and which must be included as an addition to rate base.

## IV. SUMMARY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. I have prepared a lead-lag study to separately compute the lag days associated with revenue collection from customers and the lag days associated with the utility revenue requirements, segregated between purchased gas expense and all other. These lagged revenues and expenses are combined to determine the net lag days for National Grid NH. I have computed the CWC associated with the per-books purchased gas expense for the Company, and my supplemental testimony will provide the CWC associated with the per books and pro forma non-gas CWC requirements.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does, subject to the information I will include in my supplemental testimony.

QUALIFICATIONS AND EXPERIENCE
OF
GARY L. GOBLE

I graduated from the University of Arkansas at Fayetteville in 1974 with a Bachelor of Science degree in Public Administration. In 1980, I received a Master of Business Administration degree from Saint Edward's University in Austin, Texas. Upon graduation from the University of Arkansas, I was employed by the Arkansas Public Service Commission ("APSC") and held several positions with the APSC staff, including Chief of the Rates Section and Interim Chief of the Finance Section. My activities in these positions included developing and presenting staff analyses and testimony concerning cost allocation studies and rate design for electric, natural gas, water, and telephone utilities; ensuring utility compliance with APSC rate and tariff requirements; and providing supervision and management to staff financial analysts in the determination of utility cost of capital, rate base components and capital structure.

In 1978, I accepted the position of Manager of Electric and Water Rates in the Economic Research Division of the Public Utility Commission of Texas ("PUC"). In this capacity, I was responsible for staff analyses, testimony, and activities concerning cost analysis, rate design, pricing strategies, tariffs, and econometric applications for regulated utilities.

In 1980, I was employed by Gilbert Associates, Inc. as a Management Consultant. I was promoted to Senior Management Consultant in March 1981 and to Principal Management Consultant in July 1981. In July 1981, I became Manager of Cost and Load Analysis in Gilbert Associates' Austin office. My responsibilities at this consulting firm included the duties and areas of expertise previously described, as well as undertaking or supervising activities in the area of finance and pro forma adjustments to test year costs of service. In addition, I was responsible for management of projects and project teams working on behalf of utility clients.

I became a principal at MAC at the time of its formation in May 1984. My experience at MAC included continued work in the electric and gas utility industry representing investor-owned utilities, electric cooperatives, and municipally-owned utility systems. My duties at MAC included the duties and areas of expertise described above. In addition, I participated in the analysis of financial and accounting information on behalf of utility clients. This work included the analysis and development of lead lag studies and quantification of cash working capital requirements. I remained a principal at MAC from May 1984 until January 2006.

From January 2006 through March 2007, I was employed as a management consultant by R. J. Covington Consulting, LLC. While employed by this firm, I continued to provide consulting services similar to those previously described as well as work in the areas of business valuation, affiliate transactions, cash working capital and revenue requirement adjustments in regulatory proceedings.

In April 2007 I returned to MAC as a managing consultant. My responsibilities and job duties at MAC are the same as those previously described.

I have previously testified before the PUC, the APSC, the Louisiana Public Service Commission, the Railroad Commission of Texas, and the Public Service Commission of Wyoming. In addition, I have provided formal rate presentations to a number of municipally-owned and cooperative electric utilities.

I am currently, or have in the past, been a member of the following organizations: Association of Energy Economics, Association of Energy Engineers, Association of Energy Services Professionals, American Statistical Association, NARUC Committee on Utility Billing Practices (past member), and the NARUC Ad Hoc Committee on Section 133 of PURPA (past member). During the past 34 years, I have made a number of presentations at various industry associations and trade groups.

National Grid NH
Cash Working Capital Requirements
12 Months Ended Jun 30, 2007
Lead Lag Summary

| Line No | | Annual Expense (1) | Lead (Lag) Days (2) | Day Weighted Amount (3) | Source (4) |
|---|---|---|---|---|---|
| | **Revenues** | | | | |
| 1 | Sales Revenues | $176,006,960 | 50.97 | $8,970,833,775 | Page 2 of 3 - Line 14 |
| 2 | Unbilled Revenues | 310,864 | 51.18 | 15,910,123 | Page 2 of 3 - Line 16 |
| 3 | Other Revenues | 202,363 | 58.21 | 11,780,151 | Page 2 of 3 - Line 18-26 |
| 4 | **Total Revenue Lag** | 176,520,187 | 50.98 | $8,998,524,049 | Page 2 of 3 - Line 28 |
| 5 | | | | | |
| 6 | **Operation & Maintenance Expense** | | | | |
| 7 | Purchased Gas | $135,339,224 | 38.94 | $5,270,109,385 | Page 3 of 3 - Line 2 |
| 8 | Labor | 8,482,884 | | | Page 3 of 3 - Line 3 |
| 9 | Employee Pensions & Benefits | 2,043,633 | | | Page 3 of 3 - Line 4 |
| 10 | Uncollectible Accounts | 3,693,923 | | | Page 3 of 3 - Line 5 |
| 11 | Other O&M Expenses | 6,783,136 | | | Page 3 of 3 - Line 6 |
| 12 | | | | | |
| 13 | **Depreciation Expense** | 8,824,109 | | | Page 3 of 3 - Line 9 |
| 14 | | | | | |
| 15 | **Other Taxes** | | | | |
| 16 | Other Taxes Excluding Property Taxes | 228,713 | | | Page 3 of 3 - Line 12 |
| 17 | Property Taxes | 3,533,834 | | | Page 3 of 3 - Line 13 |
| 18 | | | | | |
| 19 | **Income Taxes** | | | | |
| 20 | Federal Income Taxes | 1,670,259 | | | Page 3 of 3 - Line 17 |
| 21 | State Income Taxes | 1,007,476 | | | Page 3 of 3 - Line 18 |
| 22 | | | | | |
| 23 | **Provision for Deferred Income Taxes** | -1,034,057 | | | Page 3 of 3 - Line 21 |
| 24 | | | | | |
| 25 | **Loss From Disposition of Property** | 113,812 | | | Page 3 of 3 - Line 23 |
| 26 | | | | | |
| 27 | **Return** | | | | |
| 28 | Interest on Long-Term Debt | 2,900,000 | | | Page 3 of 3 - Line 26 |
| 29 | Interest on Short'-Term Debt | 508,859 | | | Page 3 of 3 - Line 27 |
| 30 | Income for Return | 2,424,382 | | | Page 3 of 3 - Line 28 |
| 31 | | | | | |
| 32 | **Total Expense Lag** | $176,520,187 | | | Sum of Lines 7 to 30 |
| 33 | | | | | |
| 34 | **Net of Reveune less Expense Lag** | | | | Line 4 - Line 32 |
| 35 | Days | | | | |
| 36 | | | | | |
| 37 | | | | | |
| 38 | **Avg Daily Cash Working Capital Requirements** | | | | Line 34 / Line 35 |
| 39 | | | | | |
| 40 | | | | | |
| 41 | **Cash Working Capital Requirements** | | | | Line 38 |
| 42 | | | | | |
| 43 | Numbers may vary due to rounding. | | | | |
| 44 | | | | | |
| 45 | | | | | |
| 46 | **Purchased Gas Working Capital** | | | | |
| 47 | Purchased Gas Net Lag Days | | 12.04 | | Line 4 - line 7 |
| 48 | Purchased Gas Cost | | | $135,339,224 | Line 7 |
| 49 | Purchased Gas CWC | | | **$4,464,340** | Line 48 / 365 X Line 47 |
| 50 | | | | | |
| 51 | **Base Revenue Requirements Working Capital** | | | | |
| 52 | Total Cash Working Capital Requirements | | | | Line 41 |
| 53 | Less: Purchased Gas Cash Working Capital | | | | Line 49 |
| 54 | Base Revenue Requirements Working Capital | | | | Line 52 - Line 53 |
| 55 | Base Revenue Net Lag Days | | | | Line 54/(Line32-Line7) X 365 |
| 56 | | | | | |

National Grid NH
Cash Working Capital Requirements
12 Months Ended Jun 30, 2007
Revenues Lag Summary

| Line No | Revenue Lag | Revenues Billed | Lead (Lag) Days | Source | Wtg Delivery Dollar Days |
|---|---|---|---|---|---|
| 1 | Service Lag | | 15.22 | See Note 1 | |
| 2 | | | | | |
| 3 | Billing Lag | | | | |
| 4 | Cycle Read Customers | | 1 00 | See Note 3 | |
| 5 | | | | | |
| 6 | Collection Lag | | 34.96 | W/P Supporting Page 1 Line 21 | |
| 7 | | | | | |
| 8 | Total Firm Gas Sales Revenues | $167,620,007 | 51.18 | Line 1 + 4 + 6 | $8,578,847,598 |
| 9 | | | | | |
| 10 | Sales for Resale | $3,044,423 | 38.94 | W/P Supporting Page 2 Line 21 | $118,553,693 |
| 11 | Gas Revenues Total | $170,664,430 | 50.96 | | $8,697,401,292 |
| 12 | | | | | |
| 13 | Revenues from Transportation of Gas of Others | $5,342,530 | 51.18 | Line 8 | $273,432,484 |
| 14 | Total Sales Revenues | $176,006,960 | 50.97 | | $8,970,833,775 |
| 15 | | | | | |
| 16 | Unbilled Revenues | $310,864 | 51.18 | Line 8 | $15,910,123 |
| 17 | | | | | |
| 18 | Reconnect Fees | $298,420 | 51.18 | Line 8 | $15,273,235 |
| 19 | | | | | |
| 20 | NG Check Charge | $7,225 | 40.36 | See Note 2 | $291,612 |
| 21 | | | | | |
| 22 | Broker Balancing Charges | -$9,841 | 51 18 | Line 8 | -$503,667 |
| 23 | | | | | |
| 24 | Deferred Profit Off System Sales | -$122,666 | 38.94 | Line 10 | -$4,776,755 |
| 25 | | | | | |
| 26 | Default Activity | $29,225 | 51.18 | Line 8 | $1,495,745 |
| 27 | | | | | |
| 28 | Total Revenue Lag | $176,520,187 | 50 98 | | $8,998,524,049 |
| 29 | | | | | |
| 30 | | | | | |
| 31 | Notes: | | | | |
| 32 | 1. Computed as 365.25/12/2 | | | | |
| 33 | 2. Fees are assessed on the next billing. Lag is computed as the collection lag on Line 6 plus the average of 5.4 days from due date. | | | | |
| 34 | 3. Meters are read from 7AM to 3PM and posted to accounts receivable on the following day. | | | | |
| 35 | | | | | |
| 36 | | | | | |

National Grid NH
Cash Working Capital Requirements
12 Months Ended Jun 30, 2007
Cost of Service Lead Lag Summary

| Line No | | Revenue Req Amount | Lead (Lag) Days | Source | Weighted Amount |
|---|---|---|---|---|---|
| 1 | **Operation & Maintenance Expense** | | | | |
| 2 | Purchased Gas | $135,339,224 | 38.94 | W/P Supporting Page 2 Line 21 | $5,270,280,270 |
| 3 | Labor | $8,482,884 | | | |
| 4 | Employee Pensions & Benefits - Acct 926 | $2,043,633 | | | |
| 5 | Uncollectible Accounts - Acct 904 | $3,693,923 | | | |
| 6 | Other O&M Expenses | $6,783,136 | | | |
| 7 | Total Operating & Maintenance Expenses | $156,342,800 | | | |
| 8 | | | | | |
| 9 | **Depreciation & Amortization Expense** | $8,824,109 | | | |
| 10 | | | | | |
| 11 | **Other Taxes** | | | | |
| 12 | Other Taxes Excluding Property Taxes | $228,713 | | | |
| 13 | Property Taxes | $3,533,834 | | | |
| 14 | Total Other Taxes | $3,762,548 | | | |
| 15 | | | | | |
| 16 | **Income Taxes** | | | | |
| 17 | Federal Income Taxes | $1,670,259 | | | |
| 18 | State Income Taxes | $1,007,476 | | | |
| 19 | Total Income Taxes | $2,677,735 | | | |
| 20 | | | | | |
| 21 | **Provision for Deferred Income Taxes** | -$1,034,057 | | | |
| 22 | | | | | |
| 23 | **Loss From Disposition of Property** | $113,812 | | | |
| 24 | | | | | |
| 25 | **Return** | | | | |
| 26 | Interest on Long-Term Debt - Push Down Debt | $2,900,000 | | | |
| 27 | Interest on Short'-Term Debt | $508,859 | | | |
| 28 | Income for Return | $2,424,382 | | | |
| 29 | Total Return | $5,833,241 | | | |
| 30 | | | | | |

ORIGINAL
N.H.P.U.C. Case No. DG 08-009
Exhibit No. #11
Witness
DO NOT REMOVE FROM FILE

# STATE OF NEW HAMPSHIRE
# BEFORE THE
# PUBLIC UTILITIES COMMISSION

**EnergyNorth Natural Gas, Inc.**
**d/b/a National Grid NH**

**DOCKET DG 08-009**

**Direct Testimony**
**of**
**Gary L. Goble**
**Regarding Rate Design**

**February 25, 2008**

Prepared by:

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**List of Attachments**

## I. INTRODUCTION

**Q. Please state your name, position and business address.**

A. My name is Gary L. Goble. I am a managing consultant with the firm of Management Applications Consulting, Inc. ("MAC"). MAC's headquarters is located at 1103 Rocky Drive, Suite 201, Reading, Pennsylvania 19609 while my business office is at 2218 Equestrian Trail, Austin, Texas 78727.

**Q. Are you the same Gary L. Goble who presented direct testimony on the subject of cash working capital and lead-lag studies?**

A. Yes, I am.

**Q. Please summarize your testimony.**

A. In this testimony, I will discuss the accounting and marginal cost of service studies that were performed by MAC that are used as the basis for the rates proposed in the filing by EnergyNorth Natural Gas, Inc. d/b/a National Grid NH ("Company" or "National Grid NH") in this proceeding. The accounting cost study functionalizes the Company's revenue requirement into delivery, production, direct gas costs, and indirect gas cost functions. The marginal cost study provides the basis for determining the level of revenues to be recovered from each class of service as well as component costs that are used to design rates. I sponsor and support the development of indirect gas costs that are included along with direct, or conventional, gas costs for recovery in the Cost of Gas clause ("COG"). These indirect gas costs, consisting of bad debt expense, local production costs, gas working capital and miscellaneous gas supply related costs, are recovered by means of the COG and therefore are not included for purposes of determining the Company's proposed base rates. I am also responsible for the development of class revenue requirements using the results of the marginal cost study. The marginal cost study identifies the changes in costs associated with changes in the number of customers, level of sales, and capacity requirements placed on National Grid NH's gas delivery system. Finally, I am responsible for determining the levels of revenue to be recovered from each rate class and the design of delivery rates for each customer class.

In addition to my testimony sponsoring National Grid NH's cost functionalization study, marginal cost study, and rate design, I also sponsor the Company's level of cash working capital using the results of a lead lag study prepared for National Grid NH's operations by MAC. My testimony relating to cash working capital is submitted as a separate document in this filing.

**Q. Please outline the organization of your testimony and schedules.**

A. My testimony consists of four sections beyond this one. Each one discusses the various cost and rate studies and analyses conducted as a part of this filing and is supported by attachments displaying a summary of the study results as well as key data employed in the calculations. These attachments are numbered GLG-RD-1 though GLG-RD-5.

Attachment GLG-RD-2 is described in the second section of my testimony. This schedule contains the fully allocated accounting cost of service study detailing the costs to serve the functional activities of the utility such as gas supply, delivery, direct gas costs, and indirect gas cost functions. I summarize the methods employed to create the cost study, the fundamental cost data included and the interpretation of the cost study's results. The indirect cost analysis provided in Attachment GLG-RD-

2-2 is employed to determine the level of indirect gas costs to include in the cost of gas adjustment clause.

The third section of my testimony summarizes the calculations incorporated into the Company's marginal cost of service study and presents its results as Attachment GLG-RD-3. The marginal cost to serve each class provides the basic measure of each class' proportionate share of the total costs to serve. Furthermore, the marginal cost study provides a guide to the development of the facilities charges included in the proposed rates.

The fourth section of my testimony relates to rate design. In this section, I employ the marginal cost study's results, after making an equi-proportional adjustment to class marginal costs to reconcile with National Grid NH's delivery service revenue requirements. The detailed rate design calculations are provided in Attachment GLG-RD-4 of my direct testimony.

Finally, in Attachment GLG-RD-5 I present a detailed explanation some of the more technical aspects of the accounting and marginal cost studies.

## II. ACCOUNTING COST OF SERVICE STUDY

**Q. Would you briefly define an accounting cost of service study?**

A. An accounting cost of service study may also be referred to as an "allocated" cost of service study, a "class" cost of service study or an "embedded" cost of service study. Regardless of the name, these studies all provide the same information – they divide, allocate or assign allowed revenue requirements as defined under conventional rate of return accounting to either cost functions or to individual customer classes. The costs to serve the customers of any utility company generally consist of operating expenses and return. For a historical test period, these costs have been recorded on the books and records of the utility and the overall cost to serve the collective customers of that company may be readily established. On the other hand, the costs to serve individual functions or classes of service are not directly recorded and, thus, must be derived by means of cost allocations. The purpose of an allocated cost of service study is to assign or allocate each relevant component of cost on an appropriate basis in order to determine the proper total cost to serve the respective functions or classes. The accounting cost of service study presented here, however, is not used to allocate costs to individual rate classes. That purpose is served by the marginal cost study described below. The accounting cost study presented here creates a cost matrix that enables the Commission to determine the detailed costs of the delivery function, the production/supply function, direct gas costs, and indirect gas costs.

Accounting Cost of Service Study - Summary of Costs by Function

**Q. How does the Company's accounting cost of service study relate to the development of the unbundled cost to serve the gas supply, transportation, and distribution functions?**

A. The Company's functional cost of service is presented in Attachment GLG-RD-2-1. The accounting cost study's vertical column shows the details of the rate base and expense items that determine total cost to serve. The horizontal dimension refers to functional categories, showing how each cost is allocated to each function. For example, metering investment was determined to be related to the delivery service function alone, and not to the gas supply function. As a result, the meter allocator was defined as 100% distribution customer-related. While many of the allocators used in the cost study were assigned directly to one function or another, other allocators were developed internally in the cost study, and result in allocations to more than one functional cost category. For example, some cost items were allocated on the computed value of rate base. Net plant and rate base consists of investments in liquid propane ("LP") and liquefied natural gas ("LNG") facilities, which are primarily gas supply related, and other investments that are primarily delivery service related, such as mains, services and meters. As a result, items allocated based on plant or rate base, such as deferred taxes or property taxes, reflect both a gas supply and delivery service component to their cost to serve.

**Q. Have you prepared any unbundled costs within the allocated cost of service study as part of your efforts to analyze the Company's overall costs?**

A. Yes. Following standard cost allocation procedures, Attachment GLG-RD-2-1 details unbundled cost of service results for two functions, delivery costs and production costs. Production costs are further segregated between direct gas costs and indirect gas costs. In addition, Attachment GLG-RD-2-1 provides the detailed allocations on an account by account basis, using the same methods employed in the Company's unbundling proceeding, Docket No. DG 00-063, and Cost of Gas Filing, Docket No. DG 06-121.

**Q. How do you determine the gas supply and delivery service-related costs from the unbundled cost of service study results you have presented?**

A. The delivery service costs consist solely of the distribution capacity costs and the distribution customer costs. The remaining costs are gas supply related production capacity or commodity costs. The delivery service functional costs specifically exclude direct and indirect gas costs.

Indirect Gas Costs

**Q. What are indirect gas costs?**

A. Indirect gas costs are those costs associated with supplying the gas commodity that are not included in the category of "direct" gas costs. Indirect gas costs consist primarily of the revenue requirements associated with the investment and operating expense for local manufactured gas facilities such as LP-air and liquefied natural gas facilities, bad debt expense related to the supply function, working capital related to the supply function, and other miscellaneous operations and maintenance expenses including gas acquisition (i.e., the contracting function), dispatching and administrative and general expenses relating to the supply function but not included in "direct" gas costs.

**Q. How are these functionalized costs used in the rate design process?**

A. The primary purpose of the functional cost study is to segregate revenue requirements between gas supply and delivery service revenue requirements and to simultaneously identify direct and indirect gas costs. These results are shown by function on Attachment GLG-RD-2-1. The details of indirect gas costs necessary to update the COG are summarized on Attachment GLG-RD-2-3.

**Q. How are indirect gas costs recovered?**

A. Indirect gas costs are currently recovered through the Company's COG.

**Q. Please describe in more detail the costs that are included in the indirect gas cost function.**

A. I have prepared Attachment GLG-RD-2-2 to segregate indirect gas costs into four categories:

1. LP and LNG Costs
2. Miscellaneous Production Costs
3. Bad Debt Costs and
4. Working Capital.

A major portion of LP-air and LNG-related costs are incurred to provide gas supplies on extremely cold days and are assigned to the gas supply function in the cost studies we performed. The remainder of the LP-air and LNG-related costs are incurred to provide support to the distribution system and are assigned to the distribution function in the cost studies.

I have also classified the portion of working capital associated with gas supply costs as gas supply-related and removed it from the delivery service revenue requirements. Similarly, operations and maintenance expenses associated with the gas acquisition and dispatching costs, services that are provided within the Gas Supply department, were unbundled and segregated between gas supply and delivery service. Consequently, the Company's functional cost study implicitly removes the gas supply related costs from the delivery service revenue requirement.

In an unbundled cost of service study, the uncollectible accounts expense is segregated between delivery service and gas supply functions on the basis of revenue requirements. In other words, if gas supply costs make up 50% of the cost to serve, then 50% of the bad debts are also considered gas supply-related. From this study the Company determines the fixed gas cost related bad debt percentage by dividing the gas supply related bad debt by the total gas costs. This percentage is then applied to the actual experienced gas costs to determine total gas cost related bad debt to be recovered through the Company's COG mechanism.

Finally, the proposed functionalized study assigns a portion of overhead costs, including general plant costs and administrative and general expenses, to the gas supply function through the selection of internally developed allocators. For example, the labor allocator includes the labor associated with peaking plant operations and maintenance expenses. Consequently, revenue requirements such as those stemming from general plant, that are allocated on the basis of labor will include an assignment of costs to the gas supply function.

## III. MARGINAL COST STUDY

Overview of Marginal Cost Study

**Q. Please summarize the objectives of a marginal cost study.**

A. The marginal cost study is provided in Attachment GLG-RD-3. A marginal cost study provides an estimate of the additional cost of providing an additional unit of service. These estimates are utilized as guideposts in setting rates to the extent allowed by considerations of rate continuity, intra-class equity, and customer impact.

The use of marginal costs in ratemaking tends to result in a level and pattern of prices that promotes economically rational consumption decisions, and thereby promotes an efficient allocation of society's resources. Sending customers accurate price signals regarding the costs that will result from their consumption decisions furthers efficiency. Customers, in turn, will be able to make informed decisions on their use of utility service.

**Q. How is a marginal cost study used in the rate design process?**

A. Following the precedent established by the New Hampshire Public Utilities Commission in DG 00-063, the marginal cost study is used to establish revenue levels and prices for each rate class on the basis of marginal costs, adjusted using the Equi-Proportional Method ("EPM") to recover the allowed revenue requirements. The proposed total system delivery service revenue requirements are established at the adjusted test year levels. Delivery service marginal costs by class (which differ from the revenue requirement) are then adjusted to match the delivery system total revenue requirements on a pro-rata basis using the EPM. The resulting scaled marginal costs by class and cost component become the theoretical targets for the design of delivery service rates.

**Q. Please summarize the different elements of a marginal cost study.**

A. A typical marginal cost estimate contains several components. The marginal commodity cost component is intended to reflect the short run variable cost of varying the Company's level of gas sendout by one unit, assuming the Company's production capacity is held constant. The short run marginal cost is, therefore, the cost of gas (plus indirect costs). The marginal production capacity cost component is intended to reflect the long-run cost, on a unitized basis, of expanding the Company's production facilities to meet an increase in customers' requirements for gas service.

The marginal transmission and distribution component is intended to reflect the unitized cost, based on historical data and recent trends, of expanding the local distribution network to accommodate growth in the number of customers and their requirements.

**Q. Could you provide an overview of the methodology you employed?**

A. Yes. My methods are essentially unchanged from the marginal cost study filed in Docket No. DG 00-063. I have computed the marginal costs to serve each of National Grid NH's rate classes based on test year costs. I employed the Company's supply plan alternatives to estimate production capacity costs. I have used regression and engineering techniques to estimate the hypothetical distribution costs of serving an increment of customer load, including the unit costs of adding distribution plant facilities as well as the additional costs for O&M. These distribution capacity costs were measured in terms of dollars per design day decatherm. Attachment GLG-RD-1 summarizes the development of class estimates of design day demand. I have used engineering estimates to identify the investment in services and meters and added O&M expenses necessary to serve a new customer. From these factors, I have developed the annual revenue requirements to serve each of National Grid NH's rate classes. These costs are stated in terms of customer, commodity and facilities charges. A more extensive discussion of the methods I employed in the marginal cost study is described in Attachment GLG-RD-5.

**Q. What were the results of the marginal cost study?**

A. Attachment GLG-RD-3, page 35 of 37, tabulates the long-run marginal costs to serve each customer class. In addition, the table on this page calculates the revenues that would be generated if the Company were to introduce full marginal cost-based pricing and if customers were to continue to consume as they have in the past. Attachment GLG-RD-3, page 36 of 37, provides marginal costs on a unit cost basis. Finally, Attachment GLG-RD-3, page 37 of 37, presents the EPM adjustment to restate marginal costs at a level that match the delivery service revenue requirements.

## IV. <u>RATE DESIGN</u>

<u>Rate Design Information</u>

**Q. Please describe your cost summary.**

A. Attachment GLG-RD-3, page 37 of 37, combines information from the accounting and marginal cost studies and current revenue. The schedule derives the theoretical revenue target for each class and compares it with the proposed revenue requirements. Each component of each class' rates is scaled upward or downward so that the total revenues derived from all classes at the resulting rates will produce the overall system revenue requirement proposed by National Grid NH. These costs are then employed as the basis for designing rates subject to certain limitations of customer bill impact for the upper level of prices.

<u>Class Revenue Targets</u>

**Q Please describe how you established class revenue targets.**

A. My revenue target calculations are shown on Attachment GLG-RD-4. This attachment, consisting of 5 sub-schedules was used both to establish class revenue targets and to design rates. Bill impact considerations for customers limited the maximum base rate increases that any rate class received to 125% of the system average increase. In other words, since the Company seeks a delivery system increase of 17.20% (see Attachment GLG-RD-4-3, page 2 of 5, line 38), the maximum amount any class' rates could be increased is 21.50% (i.e., 125% x 17.20%). The differences between the assigned revenue requirements and the maximum level of revenues allowed under the restriction described above were summed and then allocated on a pro-rata revenue basis to the classes whose rate increases were not affected by the limitation on the level of increase. If that redistribution of revenue resulted in any class exceeding its maximum allowed increase, the unrecovered revenue requirement for such classes were again allocated to the remaining classes unaffected by the rate caps. This process continued until the revenues produced from all classes summed to the proposed level of revenues. At that point, any classes with an indicated rate decrease were adjusted to have no change in revenues. The subsidy produced by raising these revenue targets was also allocated to the uncapped rate classes on a pro rata basis. These calculations are shown on Attachment GLG-RD-4-2.

**Q. Why did you select a revenue cap of 125%?**

A. I have selected the rate caps based on several considerations. First and foremost, I considered bill impacts. Since this rate cap is being applied to the design of delivery rates and since delivery rates are normally much less than half the customer's total energy bill, the use of the 125% rate cap did not result in undue hardship to any rate class. Second, I examined the relative difference between costs to serve and current revenues. At the present time the residential rate classes provide slightly over half of the Company's delivery revenues but account for over three quarters of its cost to serve. Assuming that the Company were to continue to experience increases in cost to serve at about 1.5% per year, the imposition of a 125% rate cap would mean that the residential subsidy would continue for well over 30 years into the future. These facts suggest that the rate cap could be much larger than 125%. Third, I examined recent regulatory practice for gas distribution utilities in the area. The Massachusetts Department of Public Utilities employed a 125% rate cap in designing delivery rates for Bay State Gas Company and Fitchburg Gas. These cases suggest that the 125% cap is not unusual and has been found to be reasonable by other regulatory authorities. Finally, I considered the period of time between rate cases. The Company's last general rate case was filed in 1991, and its most recent base rate design change occurred in 2001, so it is possible that there may not be frequent opportunities to make rate design changes going forward. Therefore, it is essential that significant progress toward cost-based rates be made when the opportunity arises. For these reasons, I concluded that a 125% rate cap would be reasonable.

Individual Rate Designs

**Q. How did you approach the design of individual rates?**

A. Once the revenue targets were established for each rate class, detailed rate design was conducted, as shown on Attachment GLG-RD-4-2. The rate design process was guided by three general principles – moving rates toward the marginal costs to serve, providing some level of rate stability for customers by controlling bill impacts, and better aligning the rate structure with the Commission's and the Company's energy efficiency goals by moving more of the revenue recovery from the volumetric portion of the rates to the customer charge.

Marginal costs to serve include two types of cost – costs that vary with the number of customers and costs that vary with the design day demands of customers. In essence, the utility must construct a distribution system capable of handling the anticipated loads of customers under extreme weather conditions. These costs are incurred regardless of the actual weather occurring in the test period, and are also independent of the volumes consumed by customers throughout the test year. Therefore, it is more appropriate to recover these costs through a fixed charge, rather than a volumetric therm charge. The very bottom of page 37 of 37 of the marginal cost study, Attachment GLG-RD-3, shows the marginal costs for each class expressed in terms of dollars per month per customer.

**Q. How did you determine customer charges?**

A. Using this general approach, the rate design process simply became a matter of raising customer charges to the limits imposed by rate stability and bill impact considerations. Once the revenue targets were established for each rate class, detailed rate design was conducted, as shown on Attachment GLG-RD-4-2. The customer charges for each class were limited to the lower of the marginal costs to serve the class or an increase of 100%.

**Q. How did you design the therm rates for each rate class?**

A. Having already established the revenue targets for each class, I subtracted the revenues derived from the proposed facility charges to compute the revenues to be produced through the therm charges. Then I made a simple pro rata adjustment to the existing therm charges to achieve the desired revenues from each class. Note that the billing units used in the design of rates are stated in terms of dry therms. Although wet therms were used to design rates in the past, the use of dry therms is standard in the natural gas industry, and it is appropriate to be adopted by the Company.

**Q. Have you provided a summary of the rates you designed?**

A. Yes, a table summarizing the rates is provided on page 3 of Attachment GLG-RD-4-3.

**Q. Did you verify that the proposed rates match the delivery revenue requirements?**

A. Yes, the proposed rates were multiplied by the appropriate weather normalized billing determinants to provide a revenue proof as shown on Attachment GLG-RD-4-4.

**Q. Have you analyzed the impact of the proposed rates on the customers within each rate class?**

A. Yes, I have prepared typical bill impact analyses for each rate class, showing the impact on the customer as a function of monthly use. I've prepared these comparisons separately for the summer and winter seasons as shown on Attachment GLG-RD-4-5. Each rate class is represented by two pages, the odd numbered pages show the bill impacts for the winter season and the even pages show the summer impacts. The monthly therm usage level is displayed vertically on these pages along the left side and the bill calculations are shown in columns both for the delivery service rate alone and in combination with gas supply charges and additional distribution charges stemming from the COG and LDAC, respectively. In addition to displaying the range of potential monthly usage, I have evaluated the distribution of monthly bills each season and shown the impact on customers located at the $25^{th}$, $50^{th}$ and $75^{th}$ percentile in terms of seasonal usage.

<u>Combining Classes</u>

**Q. Could you comment on the effectiveness of the commercial and industrial class rate definitions implemented when rates were unbundled in docket DG 00-063?**

A. The availability clauses for the rates currently in place are based on customer consumption patterns, rather than on the character of the customer. Thus, the rate class definitions result in the aggregation of customers with similar cost characteristics. This is clearly demonstrated by the unit costs to serve provided in the marginal cost study. Each rate class is well differentiated with the lowest costs to serve ascribed to the classes with the highest load factors. However, one can observe one problem that deserves attention. The G-54 rate, for large customers with load factors between 90% and 110%, has only one customer. The number of customers has declined substantially from when the rate was originally designed. In general, it is inappropriate to offer a generally available rate for only one customer.

**Q. Do you have a recommendation to resolve the issue concerning the G-54 rate?**

A. Yes, I suggest that the G-54 and G-63 classes be merged together under an availability clause of "load factor greater than 90%." The G-63 class currently has an availability clause of "load factor greater than 110%." Since the lone customer in the

G-54 class is small compared to the loads served under the G-63 rate, the impact of merging the rates would result in a minimal impact on the rates to the existing G-63 customers and would provide a 3% savings to the G-54 customer.

**Q. On what basis do you draw these conclusions?**

A. I have included an additional column on the far right side of Attachments GLG-RD-4-2, GLG-RD-4-3 and GLG-RD-4-4 to show the development of a combined G-54 and G-63 rate. In addition, the last two pages of Attachment GLG-RD-4-5 show the typical bill impacts for the combined customer class. A review of these attachments reveals that combining the two rates is a very practical alternative, and supports the conclusion that there is no reason to continue offering separate rates.

**Q. For purposes of calculating the bill impacts resulting from the new rates proposed by the Company as shown on Attachment GLG-RD-4-3, page 5 and Attachment GLG-RD-4-5, what assumptions did you make regarding the gas cost portion of customers' bills?**

A. For comparative purposes, the Company used the direct gas cost portion of the COG rates in effect from May 2007 through October 2007 for the off peak period and the direct gas cost portion of the COG rates approved in November 2007 for the peak period. These direct gas costs were assumed to be the same for both the period covered by current rates and the period covered by the proposed rates. For the indirect gas cost portion of the proposed COG rates, the Company used the proposed indirect gas costs contained in Attachment GLG-RD 2-3 for the period covered by the new rates. For the current COG rates, in order to be conservative, the Company used the last approved indirect gas costs. For bad debt and working capital percentages, these were the levels approved in Docket DG 00-063. Even though new bad debt and working capital rates were agreed to in Docket DG 07-050, the settlement in that case has not yet been approved, so the older rates were employed for bill comparison purposes. For the production and storage costs and miscellaneous gas costs, the levels were last approved in Docket DG 06-121, and so those costs were used.

**Q. In your opinion, are the costs and rates employed in your analyses just and reasonable?**

A. Yes, the costs and the proposed rates are just and reasonable. Further, the rates are not unduly discriminatory. Finally, the rates represent a careful balancing of the costs of providing gas delivery service with customer impact concerns.

**Q. Does this conclude your testimony?**

A. Yes, it does.

**National Grid NH**
**Rate Design Data**
**2006 Design Day Estimate**

| | | Econometric Specification (Based on Wet Sales) Intercept | HDD Coefficient | Base Use/Day | Htg Use | Estimated Design Day Wet Sales @ Meter | Estimated Design Day Dry Sales @ Gate | Adjusted Dry Total @ Gate | Adjusted Dry Sales @ Meter |
|---|---|---|---|---|---|---|---|---|---|
| 1 | R1 | 5,719 | 6.53 | 188 | 477 | 665 | 692 | 753 | 736 |
| 2 | R3 | 68,272 | 666.54 | 2,245 | 48,658 | 50,902 | 52,948 | | |
| 3 | R4 | 1,822 | 54.34 | 60 | 3,967 | 4,027 | 4,189 | 62,165 | 60,766 |
| 4 | G41 | (3,040) | 271.71 | (100) | 19,835 | 19,735 | 20,528 | 22,334 | 21,832 |
| 5 | G42 | 33,011 | 385.16 | 1,085 | 28,117 | 29,202 | 30,375 | 33,049 | 32,305 |
| 6 | G43 | 11,021 | 59.15 | 362 | 4,318 | 4,680 | 4,868 | 5,297 | 5,178 |
| 7 | G51 | 17,594 | 26.13 | 578 | 1,907 | 2,486 | 2,586 | 2,813 | 2,750 |
| 8 | G52 | 36,655 | 31.42 | 1,205 | 2,293 | 3,499 | 3,639 | 3,959 | 3,870 |
| 9 | G53 | 57,394 | 37.12 | 1,887 | 2,709 | 4,596 | 4,781 | 5,202 | 5,085 |
| 10 | G54 | Extrapolate from Peak | | | | | 77 | 84 | 82 |
| 11 | G63 | Month's Avg Use/Day {1} | | | | | 2,706 | 2,944 | 2,878 |
| 12 | | | | | | | | | |
| 13 | Sum | | | | | | 127,388 | | |
| 14 | | | | | | | | | |
| 15 | System Forecasted Total | | | | | | 138,600 | 138,600 | 135,482 |
| 16 | Difference | | | | | | 11,212 | | 3,118 |
| 17 | % | | | | | | 8.1% | | 2.25% |

{1} High load factor class regessions were not significant

| | | |
|---|---|---|
| Days/Month = | **30.42** | |
| Design Day HDD = | **73** | |
| Loss Factor = | **2.25%** | |
| Wet/Dry Factor = | **98.30%** | |
| Design Day Load = | **138,600** | (Dry) |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | SUMMARY OF RESULTS PRESENT RATES | | | | | | |
| | RATE BASE | | | | | | |
| 1 | GAS PLANT IN SERVICE | | 263,135,986 | 250,782,178 | 12,353,808 | 0 | 12,353,808 |
| 2 | LESS: DEPREC & AMORT RES | | 89,825,741 | 81,010,787 | 8,814,953 | 0 | 8,814,953 |
| 3 | PLUS: CWIP | | 4,510,701 | 4,510,701 | 0 | 0 | 0 |
| 4 | NET UTILITY PLANT IN SERVICE | | 177,820,946 | 174,282,092 | 3,538,854 | 0 | 3,538,854 |
| | ADD: | | | | | | |
| 5 | WORKING CAPITAL REQUIREMENTS | | 6,937,148 | 2,252,826 | 4,684,323 | 0 | 4,684,323 |
| 6 | PREPAYMENTS | | 155,604 | 148,299 | 7,305 | 0 | 7,305 |
| | DEDUCT: | | | | | | |
| 7 | DEFERRED FUEL COSTS | | 0 | 0 | 0 | 0 | 0 |
| 8 | DEFERRED DEMAND SIDE MGMNT COSTS | | 0 | 0 | 0 | 0 | 0 |
| 9 | DEFERRED ENVIORMENTAL COSTS | | 0 | 0 | 0 | 0 | 0 |
| 10 | UNAMORTIZED DEFERRED ASSETS - OTH | | (4,170,788) | (3,974,976) | (195,812) | 0 | (195,812) |
| 11 | ACCUM DEFERRED INCOME TAX | | 41,047,147 | 39,120,050 | 1,927,097 | 0 | 1,927,097 |
| 12 | RATE BASE | | 148,037,339 | 141,538,142 | 6,499,197 | 0 | 6,499,197 |
| | DEVELOPMENT OF RETURN | | | | | | |
| 13 | TOTAL SALES REVENUE | | 178,812,382 | 42,224,238 | 136,588,144 | 133,114,231 | 3,473,913 |
| 14 | OTHER OPERATING REVENUE | | 2,046,919 | 1,260,973 | 785,946 | 0 | 785,946 |
| 15 | TOTAL GAS OPERATING REV | | 180,859,301 | 43,485,211 | 137,374,090 | 133,114,231 | 4,259,859 |
| | LESS: | | | | | | |
| 16 | PURCHASE GAS COSTS | | 133,114,231 | 0 | 133,114,231 | 133,114,231 | 0 |
| 17 | OTHER OPER & MAINT EXPENSE EXCL UNCOLL | | 21,941,727 | 19,818,121 | 2,123,606 | 0 | 2,123,606 |
| 18 | UNCOLLECTIBLE ACCTS EXPENSE | | 4,593,826 | 1,208,248 | 3,385,578 | 0 | 3,385,578 |
| 19 | DEPRECIATION EXPENSE | | 7,770,704 | 7,566,466 | 204,237 | 0 | 204,237 |
| 20 | OTHER TAXES | | 3,812,961 | 3,625,908 | 187,052 | 0 | 187,052 |
| 21 | INCOME TAXES | | 1,803,600 | 2,566,634 | (763,034) | 0 | (763,034) |
| 22 | TOTAL OPERATING EXPENSES | | 173,037,048 | 34,785,377 | 138,251,671 | 133,114,231 | 5,137,440 |
| 23 | OPERATING INCOME | | 7,822,253 | 8,699,833 | (877,581) | 0 | (877,581) |
| 24 | RATE OF RETURN | | 5.28% | 6.15% | -13.50% | 0.00% | -13.50% |
| 25 | INDEX RATE OF RETURN | | 1.000 | 1.163 | -2.555 | 0.000 | -2.555 |
| 26 | NET REVENUES | | 45,698,151 | 42,224,238 | 3,473,913 | 0 | 3,473,913 |

| | SUMMARY OF RESULTS CLAIMED RATES-2 | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | RATE BASE | | | | | | |
| 1 | GAS PLANT IN SERVICE | | 263,135,986 | 250,782,178 | 12,353,808 | 0 | 12,353,808 |
| 2 | LESS: DEPREC & AMORT RES | | 89,825,741 | 81,010,787 | 8,814,953 | 0 | 8,814,953 |
| 3 | PLUS: CWIP | | 4,510,701 | 4,510,701 | 0 | 0 | 0 |
| 4 | NET UTILITY PLANT IN SERVICE | | 177,820,946 | 174,282,092 | 3,538,854 | 0 | 3,538,854 |
| | ADD: | | | | | | |
| 5 | WORKING CAPITAL REQUIREMENTS | | 6,937,148 | 2,252,826 | 4,684,323 | 0 | 4,684,323 |
| 6 | PREPAYMENTS | | 155,604 | 148,299 | 7,305 | 0 | 7,305 |
| | DEDUCT: | | | | | | |
| 7 | DEFERRED FUEL COSTS | | 0 | 0 | 0 | 0 | 0 |
| 8 | DEFERRED DEMAND SIDE MGMNT COSTS | | 0 | 0 | 0 | 0 | 0 |
| 9 | DEFERRED ENVIORMENTAL COSTS | | 0 | 0 | 0 | 0 | 0 |
| 10 | UNAMORTIZED DEFERRED ASSETS - OTH | | (4,170,788) | (3,974,976) | (195,812) | 0 | (195,812) |
| 11 | ACCUM DEFERRED INCOME TAX | | 41,047,147 | 39,120,050 | 1,927,097 | 0 | 1,927,097 |
| 12 | RATE BASE | | 148,037,339 | 141,538,142 | 6,499,197 | 0 | 6,499,197 |
| | DEVELOPMENT OF RETURN | | | | | | |
| 13 | TOTAL SALES REVENUE | | 188,708,985 | 49,633,399 | 139,075,586 | 133,114,231 | 5,961,355 |
| 14 | OTHER OPERATING REVENUE | | 2,046,919 | 1,260,973 | 785,946 | 0 | 785,946 |
| 15 | TOTAL GAS OPERATING REV | | 190,755,904 | 50,894,372 | 139,861,532 | 133,114,231 | 6,747,301 |
| | LESS: | | | | | | |
| 16 | PURCHASE GAS COSTS | | 133,114,231 | 0 | 133,114,231 | 133,114,231 | 0 |
| 17 | OTHER OPER & MAINT EXPENSE EXCL UNCOLL | | 21,941,727 | 19,818,121 | 2,123,606 | 0 | 2,123,606 |
| 18 | UNCOLLECTIBLE ACCTS EXPENSE | | 4,593,826 | 1,208,248 | 3,385,578 | 0 | 3,385,578 |
| 19 | DEPRECIATION EXPENSE | | 7,770,704 | 7,566,466 | 204,237 | 0 | 204,237 |
| 20 | OTHER TAXES | | 3,812,961 | 3,625,908 | 187,052 | 0 | 187,052 |
| 21 | INCOME TAXES | | 5,814,199 | 5,569,197 | 245,002 | 0 | 245,002 |
| 22 | TOTAL OPERATING EXPENSES | | 177,047,647 | 37,787,940 | 139,259,707 | 133,114,231 | 6,145,476 |
| 23 | OPERATING INCOME | | 13,708,258 | 13,106,432 | 601,826 | 0 | 601,826 |
| 24 | RATE OF RETURN | | 9.26% | 9.26% | 9.26% | 0.00% | 9.26% |
| 25 | INDEX RATE OF RETURN | | 1.000 | 1.000 | 1.000 | 0.000 | 1.000 |
| 26 | NET REVENUES | | 55,594,754 | 49,633,399 | 5,961,355 | 0 | 5,961,355 |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | REVENUE REQUIREMENTS-3 | | | | | | |
| | PRESENT RATES | | | | | | |
| 1 | RATE BASE | | 148,037,339 | 141,538,142 | 6,499,197 | 0 | 6,499,197 |
| 2 | NET OPER INC (PRESENT RATES) | | 7,822,253 | 8,699,833 | (877,581) | 0 | (877,581) |
| 3 | RATE OF RETURN (PRES RATES) | | 5.28% | 6.15% | -13.50% | 0.00% | -13.50% |
| 4 | RELATIVE RATE OF RETURN | | 1.000 | 1.163 | -2.555 | 0.000 | -2.555 |
| 5 | SALES REVENUE (PRE RATES) | | 178,812,382 | 42,224,238 | 136,588,144 | 133,114,231 | 3,473,913 |
| 6 | ANNUAL BOOKED THERM SALES | | 150,369,039 | 150,369,039 | 117,009,709 | 117,009,709 | 117,009,709 |
| 7 | SALES PRESENT REV ($/THERM) | | $1.1892 | $0.2808 | $1.1673 | $1.1376 | $0.0297 |
| 8 | NET REVENUES (PRE RATES) | | 45,698,151 | 42,224,238 | 3,473,913 | 0 | 3,473,913 |
| 9 | NET PRESENT REV ($/THERM) | | $0.3039 | $0.2808 | $0.0297 | $0.0000 | $0.0297 |
| | CLAIMED RATE OF RETURN | | | | | | |
| 10 | CLAIMED RATE OF RETURN | | 9.26% | 9.26% | 9.26% | 9.26% | 9.26% |
| 11 | RETURN REQ FOR CLAIMED ROR | | 13,708,258 | 13,106,432 | 601,826 | 0 | 601,826 |
| 12 | SALES REVENUE REQ CLAIMED ROR | | 188,708,985 | 49,633,399 | 139,075,586 | 133,114,231 | 5,961,355 |
| 13 | REVENUE DEFICIENCY SALES REV | | 9,896,603 | 7,409,161 | 2,487,442 | 0 | 2,487,442 |
| 14 | PERCENT INCREASE REQUIRED | | 5.53% | 17.55% | 1.82% | 0.00% | 71.60% |
| 15 | ANNUAL BOOKED THERM SALES | | 150,369,039 | 150,369,039 | 117,009,709 | 117,009,709 | 117,009,709 |
| 16 | SALES REV REQUIRED ($/THERM) | | $1.2550 | $0.3301 | $1.1886 | $1.1376 | $0.0509 |
| 17 | REVENUE DEFICIENCY ($/THERM) | | $0.0658 | $0.0493 | $0.0213 | $0.0000 | $0.0213 |
| 18 | NET REVENUES CLAIMED ROR | | 55,594,754 | 49,633,399 | 5,961,355 | 0 | 5,961,355 |
| 19 | NET REV REQUIRED ($/THERM) | | $0.3697 | $0.3301 | $0.0509 | $0.0000 | $0.0509 |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | DEVELOPMENT OF RATE BASE-4 | | | | | | |
| | GAS PLANT IN SERVICE | | | | | | |
| | INTANGIBLE PLANT | | | | | | |
| 1 | 901.1-ORGANIZATION COSTS | PLANT | 0 | 0 | 0 | 0 | 0 |
| 2 | 901.3-MISC INTANGIBLE PLANT | PLANT | 23,053 | 21,970 | 1,082 | 0 | 1,082 |
| 3 | TOTAL INTANGIBLE PLANT | | 23,053 | 21,970 | 1,082 | 0 | 1,082 |
| | PRODUCTION PLANT | | | | | | |
| 4 | 902.1-LAND & LAND RIGHTS | DPROD | 394,087 | 48,867 | 345,220 | 0 | 345,220 |
| 5 | 903.1-STRUCTURES & IMPROV | DPROD | 1,195,433 | 148,234 | 1,047,199 | 0 | 1,047,199 |
| 6 | 904.1-PROD EQ PUMPING & REGUL | DPROD | 2,465,980 | 305,781 | 2,160,198 | 0 | 2,160,198 |
| 7 | 904.2-PROD EQ-PEAK SHAVING | DPROD | 9,002,322 | 1,116,286 | 7,886,034 | 0 | 7,886,034 |
| 8 | 904.3-PROD EQUIP-OTHER | DPROD | 0 | 0 | 0 | 0 | 0 |
| 9 | 904.4-PROD EQ-VEHICLE REFUEL | DPROD | 0 | 0 | 0 | 0 | 0 |
| 10 | TOTAL PRODUCTION PLANT | | 13,057,822 | 1,619,170 | 11,438,652 | 0 | 11,438,652 |
| | DISTRIBUTION PLANT | | | | | | |
| 11 | 902.2-LAND & LAND RIGHTS | DISTR | 197,764 | 197,764 | 0 | 0 | 0 |
| 12 | 903.2-STRUCTURES & IMPROV | DISTR | 544,322 | 544,322 | 0 | 0 | 0 |
| 13 | 905-MAINS | DISTR | 135,833,500 | 135,833,500 | 0 | 0 | 0 |
| 14 | 907-SERVICES | CUST907 | 80,898,885 | 80,898,885 | 0 | 0 | 0 |
| 15 | 908-METERS | CUST908 | 21,313,537 | 21,313,537 | 0 | 0 | 0 |
| 16 | TOTAL DISTRIBUTION PLANT | | 238,788,008 | 238,788,008 | 0 | 0 | 0 |
| | GENERAL PLANT | | | | | | |
| 17 | 902.3-LAND & LAND RIGHTS | LABOR | 16,550 | 15,207 | 1,343 | 0 | 1,343 |
| 18 | 903.3-STRUCTURES & IMPROV | LABOR | 1,568,455 | 1,441,210 | 127,245 | 0 | 127,245 |
| 19 | 951-COMPUTER EQUIPMENT | LABOR | 7,157,593 | 6,576,914 | 580,679 | 0 | 580,679 |
| 20 | 952-COMMUNICATION EQUIP | LABOR | 327,188 | 300,644 | 26,544 | 0 | 26,544 |
| 21 | 953-LABORATORY EQUIPMENT | LABOR | 383,480 | 352,369 | 31,111 | 0 | 31,111 |
| 22 | 954-OFFICE FURNITURE & EQUIP | LABOR | 140,164 | 128,793 | 11,371 | 0 | 11,371 |
| 23 | 955-TRANSPORTATION EQUIPMENT | LABOR | 689,425 | 633,493 | 55,931 | 0 | 55,931 |
| 24 | 956.1-GENERAL TOOLS & IMPLEM | LABOR | 799,663 | 734,788 | 64,875 | 0 | 64,875 |
| 25 | 956.2-STORES EQUIPMENT | LABOR | 42,888 | 39,409 | 3,479 | 0 | 3,479 |
| 26 | 956.3-MISCELLANEOUS EQUIP | LABOR | 141,699 | 130,203 | 11,496 | 0 | 11,496 |
| 27 | 960-LEASEHOLD IMPROVEMENTS | LABOR | 0 | 0 | 0 | 0 | 0 |
| 28 | TOTAL GENERAL PLANT | | 11,267,103 | 10,353,030 | 914,073 | 0 | 914,073 |
| 29 | TOTAL GAS PLANT IN SERVICE | | 263,135,986 | 250,782,178 | 12,353,808 | 0 | 12,353,808 |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | DEVELOPMENT OF RATE BASE CONT-5 | | | | | | |
| | DEPRECIATION & AMORTIZATION RESERVE | | | | | | |
| | INTANGIBLE PLANT RESERVE | | | | | | |
| 1 | 901.1-ORGANIZATION COSTS | PLT901.1 | 0 | 0 | 0 | 0 | 0 |
| 2 | 901.3-MISC INTANGIBLE PLANT | PLT901.3 | 132 | 126 | 6 | 0 | 6 |
| 3 | TOTAL INTANGIBLE PLT RESERVE | | 132 | 126 | 6 | 0 | 6 |
| | PRODUCTION PLANT RESERVE | | | | | | |
| 1 | 903.1-STRUCTURES & IMPROV | PLT903.1 | 1,036,344 | 128,507 | 907,837 | 0 | 907,837 |
| 2 | 904.1-PROD EQ PUMPING & REGUL | PLT904.1 | 649,841 | 80,580 | 569,261 | 0 | 569,261 |
| 3 | 904.2-PROD EQ-PEAK SHAVING | PLT904.2 | 7,773,437 | 963,906 | 6,809,531 | 0 | 6,809,531 |
| 4 | 904.3-PROD EQUIP-OTHER | PLT904.3 | 0 | 0 | 0 | 0 | 0 |
| 5 | 904.4-PROD EQ-VEHICLE REFUEL | PLT904.4 | 0 | 0 | 0 | 0 | 0 |
| 6 | TOTAL PRODUCTION RESERVE | | 9,459,622 | 1,172,993 | 8,286,629 | 0 | 8,286,629 |
| | DISTRIBUTION PLANT RESERVE | | | | | | |
| 7 | 903.2-STRUCTURES & IMPROV | PLT903.2 | 333,667 | 333,667 | 0 | 0 | 0 |
| 8 | 905-MAINS | PLT905 | 39,398,677 | 39,398,677 | 0 | 0 | 0 |
| 9 | 907-SERVICES | PLT907 | 23,325,670 | 23,325,670 | 0 | 0 | 0 |
| 10 | 908-METERS | PLT908 | 10,795,782 | 10,795,782 | 0 | 0 | 0 |
| 11 | TOTAL DISTRIBUTION PLANT | | 73,853,797 | 73,853,797 | 0 | 0 | 0 |
| | GENERAL PLANT | | | | | | |
| 12 | 903.3-STRUCTURES & IMPROV | PLT903.3 | 1,328,139 | 1,220,390 | 107,749 | 0 | 107,749 |
| 13 | 951-COMPUTER EQUIPMENT | PLT951 | 3,213,298 | 2,952,611 | 260,687 | 0 | 260,687 |
| 14 | 952-COMMUNICATION EQUIP | PLT952 | 124,607 | 114,498 | 10,109 | 0 | 10,109 |
| 15 | 953-LABORATORY EQUIPMENT | PLT953 | 444,768 | 408,685 | 36,083 | 0 | 36,083 |
| 16 | 954-OFFICE FURNITURE & EQUIP | PLT954 | 150,454 | 138,248 | 12,206 | 0 | 12,206 |
| 17 | 955-TRANSPORTATION EQUIPMENT | PLT955 | 802,096 | 737,024 | 65,072 | 0 | 65,072 |
| 18 | 956.1-GENERAL TOOLS & IMPLEM | PLT956 | 309,163 | 284,081 | 25,082 | 0 | 25,082 |
| 19 | 956.2-STORES EQUIPMENT | PLT956.2 | 36,964 | 33,965 | 2,999 | 0 | 2,999 |
| 20 | 956.3-MISCELLANEOUS EQUIP | PLT956.3 | 102,701 | 94,369 | 8,332 | 0 | 8,332 |
| 21 | 960-LEASEHOLD IMPROVEMENTS | PLT960 | 0 | 0 | 0 | 0 | 0 |
| 22 | TOTAL GENERAL RESERVE | | 6,512,189 | 5,983,871 | 528,318 | 0 | 528,318 |
| 23 | TOTAL DEPRECIATION RESERVE | | 89,825,741 | 81,010,787 | 8,814,953 | 0 | 8,814,953 |
| 24 | CWIP | DISTPLT | 4,510,701 | 4,510,701 | 0 | 0 | 0 |
| 25 | NET UTILITY PLANT IN SERVICE | | 177,820,946 | 174,282,092 | 3,538,854 | 0 | 3,538,854 |

| | DEVELOPMENT OF RATE BASE CONT-6 | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | ADDITIONS TO NET PLANT | | | | | | |
| | WORKING CAPITAL REQUIREMENTS | | | | | | |
| | CASH WORKING CAPITAL | | | | | | |
| 1 | OTHER O&M | OMEXPX | 2,472,808 | 2,252,826 | 219,982 | 0 | 219,982 |
| 2 | GAS COSTS | | 4,464,340 | 0 | 4,464,340 | 0 | 4,464,340 |
| 3 | TOTAL CASH WORKING CAPITAL | | 6,937,148 | 2,252,826 | 4,684,323 | 0 | 4,684,323 |
| | MATERIALS & SUPPLIES | | | | | | |
| 4 | FUEL | | 0 | 0 | 0 | 0 | 0 |
| 5 | OTHER | PLANT | 0 | 0 | 0 | 0 | 0 |
| 6 | TOTAL MATERIALS & SUPPLIES | | 0 | 0 | 0 | 0 | 0 |
| 7 | TOTAL WORKING CAPITAL | | 6,937,148 | 2,252,826 | 4,684,323 | 0 | 4,684,323 |
| | PREPAYMENTS | | | | | | |
| 8 | FUEL | | 0 | 0 | 0 | 0 | 0 |
| 9 | OTHER | PLANT | 155,604 | 148,299 | 7,305 | 0 | 7,305 |
| 10 | TOTAL PREPAYMENTS | | 155,604 | 148,299 | 7,305 | 0 | 7,305 |
| 11 | TOTAL ADDITIONS TO NET PLANT | | 7,092,752 | 2,401,124 | 4,691,628 | 0 | 4,691,628 |

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| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | DEVELOPMENT OF RATE BASE CONT-7 | | | | | | |
| | DEDUCTIONS FROM NET PLANT | | | | | | |
| 1 | DEFERRED FUEL COSTS | | 0 | 0 | 0 | 0 | 0 |
| 2 | DEFERRED DEMAND SIDE MGMNT COSTS | PLANT | 0 | 0 | 0 | 0 | 0 |
| 3 | DEFERRED ENVIORMENTAL COSTS | PLANT | 0 | 0 | 0 | 0 | 0 |
| 4 | UNAMORTIZED DEFERRED ASSETS - OTHER | PLANT | (4,170,788) | (3,974,976) | (195,812) | 0 | (195,812) |
| 5 | ACCUM DEFERRED INCOME TAX | PLANT | 41,047,147 | 39,120,050 | 1,927,097 | 0 | 1,927,097 |
| 6 | TOTAL DEDUCTIONS TO NET PLANT | | 36,876,360 | 35,145,074 | 1,731,285 | 0 | 1,731,285 |
| 7 | TOTAL RATE BASE | | 148,037,339 | 141,538,142 | 6,499,197 | 0 | 6,499,197 |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | OPERATING REVENUES-8 | | | | | | |
| | GAS OPERATING REVENUES | | | | | | |
| 1 | TOTAL SALES REVENUES | | 178,812,362 | 42,224,238 | 136,588,144 | 133,114,231 | 3,473,913 |
| | OTHER OPERATING REVENUES | | | | | | |
| 2 | 609-LATE PAYMENT CHARGES | REVCLAIM | 1,044,760 | 274,788 | 769,972 | 0 | 769,972 |
| 3 | 610-BAD CHECK CHARGES | REVCLAIM | 21,675 | 5,701 | 15,974 | 0 | 15,974 |
| 4 | NON CORE SALES MARGINS | DISTR | 682,064 | 682,064 | 0 | 0 | 0 |
| 5 | RECONNECT FEES | CUSTCONN | 298,420 | 298,420 | 0 | 0 | 0 |
| 6 | TOTAL OTHER OPERATING REVENUE | | 2,046,919 | 1,260,973 | 785,946 | 0 | 785,946 |
| 7 | TOTAL OPERATING REVENUES | | 180,859,301 | 43,485,211 | 137,374,090 | 133,114,231 | 4,259,859 |
| | OPERATION & MAINTENANCE EXP | | | | | | |
| | GAS PRODUCTION EXPENSES | | | | | | |
| | LIQUEFIED PROPANE GAS PRODUCTION | | | | | | |
| | OPERATION EXPENSE | | | | | | |
| 7 | 701-SUPERVISION | TLABP | 0 | 0 | 0 | 0 | 0 |
| 8 | 707-OTHER PRODUCTION LABOR | DPROD | 365,318 | 45,299 | 320,019 | 0 | 320,019 |
| 9 | 718.1-LIQUID PETROLEOUM GAS | ELPG | 188,422 | 0 | 188,422 | 0 | 188,422 |
| 10 | 718.2-LIQUID NATURAL GAS PRO FORMA | ELNG | 1,971,218 | 0 | 1,971,218 | 1,971,218 | 0 |
| | 722-OTH PROD SUPPLIES & EXP | | | | | | |
| 11 | GAS SUPPLY | GASSUP | 150,067 | 0 | 150,067 | 0 | 150,067 |
| 12 | DELIVERY SERVICE | DISTR | 34,636 | 34,636 | 0 | 0 | 0 |
| 13 | TOTAL ACCOUNT 722 | | 184,703 | 34,636 | 150,067 | 0 | 150,067 |
| 14 | 735-OTH PROD RENT | DPROD | 8,080 | 1,002 | 7,078 | 0 | 7,078 |
| 15 | TOTAL OPERATION EXPENSE | | 2,717,741 | 80,937 | 2,636,804 | 1,971,218 | 665,585 |
| | MAINTENANCE | | | | | | |
| 16 | 726-MAINT OF GENERATION EQ | DPROD | 272,776 | 33,824 | 238,952 | 0 | 238,952 |
| 17 | 727-MAINT OF MISCELLANEOUS EQ | DPROD | 0 | 0 | 0 | 0 | 0 |
| 18 | TOTAL MAINTENANCE EXPENSE | | 272,776 | 33,824 | 238,952 | 0 | 238,952 |
| 19 | TOTAL PRODUCTION EXPENSE | | 2,990,517 | 114,762 | 2,875,755 | 1,971,218 | 904,537 |
| | PURCHASED GAS SUPPLY EXPENSES | | | | | | |
| 20 | 738.1-PURCHASED GAS PRO FORMA | GASCOSTS | 131,143,013 | 0 | 131,143,013 | 131,143,013 | 0 |
| 21 | 738.2-COST OF GAS ADJ | GASCOSTS | 0 | 0 | 0 | 0 | 0 |
| 22 | TOTAL PURCHASED GAS COST | | 131,143,013 | 0 | 131,143,013 | 131,143,013 | 0 |
| 23 | TOTAL PRODUCTION EXPENSE | | 134,133,529 | 114,762 | 134,018,768 | 133,114,231 | 904,537 |

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| | OPERATION & MAINT EXP CONT-9 | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | DISTRIBUTION EXPENSES | | | | | | |
| | OPERATION EXPENSE | | | | | | |
| 1 | 756-SUPERVISION | TLABDO | 0 | 0 | 0 | 0 | 0 |
| 2 | 761-OPER OF DISTR LINES | PLT905 | 1,377,777 | 1,377,777 | 0 | 0 | 0 |
| 3 | 762.1-METER OPER LABOR & EXP | PLT908 | 1,178,563 | 1,178,563 | 0 | 0 | 0 |
| 4 | 762.2-OTHER EXP ON CUST PREM | DISTR | 0 | 0 | 0 | 0 | 0 |
| 5 | TOTAL OPERATION EXPENSE | | 2,556,340 | 2,556,340 | 0 | 0 | 0 |
| | MAINTENANCE | | | | | | |
| 6 | 765-MAINT OF STRUCTURES | PLT903.2 | 18,207 | 18,207 | 0 | 0 | 0 |
| 7 | 768-MAINTENANCE OF DISTR LINES | PLT905 | 3,300,546 | 3,300,546 | 0 | 0 | 0 |
| 8 | 771-MAINTENANCE OF SERVICES | PLT907 | 1,036,763 | 1,036,763 | 0 | 0 | 0 |
| 9 | 772-MAINT OF CUSTOMER METERS | PLT908 | 155,808 | 155,808 | 0 | 0 | 0 |
| 10 | TOTAL MAINTENANCE EXPENSE | | 4,511,324 | 4,511,324 | 0 | 0 | 0 |
| 11 | TOTAL DISTRIBUTION EXPENSE | | 7,067,664 | 7,067,664 | 0 | 0 | 0 |
| | CUSTOMER ACCOUNTING EXPENSES | | | | | | |
| 12 | 780-CUST ORD, MET RDG & COLL | CUST780 | 231,135 | 231,135 | 0 | 0 | 0 |
| 13 | 781-CUSTOMER BILLING & ACCTG | CUST781 | 2,292,771 | 2,292,771 | 0 | 0 | 0 |
| 14 | 783-UNCOLLECTIBLE ACCTS PRO FORMA | REVCLAIM | 4,593,826 | 1,208,248 | 3,385,578 | 0 | 3,385,578 |
| 15 | TOTAL CUSTOMER ACCOUNTS | | 7,117,732 | 3,732,154 | 3,385,578 | 0 | 3,385,578 |
| | SALES EXPENSE | | | | | | |
| 16 | 787-OTHER EXPENSES | GENPLT | 1,680,591 | 1,544,248 | 136,342 | 0 | 136,342 |
| 17 | TOTAL SALES EXPENSE | | 1,680,591 | 1,544,248 | 136,342 | 0 | 136,342 |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | OPERATION & MAINT EXP CONT-10 | | | | | | |
| | ADMINISTRATIVE & GENERAL | | | | | | |
| | OPERATION | | | | | | |
| 1 | 791-GENERAL OFFICE SALARIES | LABOR | 3,644,581 | 3,348,904 | 295,676 | 0 | 295,676 |
| 2 | 793-OFFICE SUPPLIES & EXP | LABOR | 1,317,801 | 1,210,891 | 106,910 | 0 | 106,910 |
| 3 | 794-SUPERV FEES & SPEC SERV | LABOR | 516,396 | 474,502 | 41,894 | 0 | 41,894 |
| 4 | 797-REGULATORY COMM EXP | REVCLAIM | 670,498 | 176,351 | 494,147 | 0 | 494,147 |
| 5 | 798-INSURANCE | LABOR | 77,110 | 70,854 | 6,256 | 0 | 6,256 |
| 6 | 799-INJURIES & DAMAGES | LABOR | 128,900 | 118,443 | 10,457 | 0 | 10,457 |
| 7 | 800-EMPLOYEE WELFARE & RELIEF | LABOR | 2,099,215 | 1,928,911 | 170,304 | 0 | 170,304 |
| 8 | 801-MISC GENERAL EXPENSE | LABOR | 1,500 | 1,378 | 122 | 0 | 122 |
| 9 | 810-ACCOUNT SERVICE CHARGES | LABOR | 0 | 0 | 0 | 0 | 0 |
| 10 | TOTAL OPERATION EXPENSE | | 8,456,000 | 7,330,234 | 1,125,766 | 0 | 1,125,766 |
| | MAINTENANCE | | | | | | |
| 11 | 802.1-BLDG MAINT & EXP | GENPLT | 0 | 0 | 0 | 0 | 0 |
| 12 | 806-A&G TRANSFER | AGX806 | 36,196 | 31,377 | 4,819 | 0 | 4,819 |
| 13 | TOTAL ADMINISTRATIVE & GEN | | 8,492,196 | 7,361,612 | 1,130,585 | 0 | 1,130,585 |
| 14 | TOT OPER & MAINT EXP BEFORE ADJ BELOW | | 158,491,713 | 19,820,439 | 138,671,274 | 133,114,231 | 5,557,043 |
| | **PRO FORMA ADJUSTMENTS** | | | | | | |
| | GAS PRODUCTION | | | | | | |
| | NATURAL GAS PRODUCTION & GATHERING | | | | | | |
| 15 | OPERATION | PRODOPX | (454) | (66) | (388) | 0 | (388) |
| 16 | MAINTENANCE | PRODMNX | (104) | (13) | (91) | 0 | (91) |
| 17 | TOTAL NAT GAS PROD & GATHERING | | (558) | (79) | (479) | 0 | (479) |
| 18 | OTHER GAS SUPPLY EXPENSE | GASSUP | (1) | 0 | (1) | 0 | (1) |
| 19 | NATURAL GAS STORAGE | GASSUP | (25) | 0 | (25) | 0 | (25) |
| | DISTRIBUTION EXPENSES | | | | | | |
| 20 | DISTRIBUTION OPERATIONS | EXP7612 | 1,165,465 | 1,165,465 | 0 | 0 | 0 |
| 21 | DISTRIBUTION MAINTENANCE | EXP7652 | 36,835 | 36,835 | 0 | 0 | 0 |
| 22 | TOTAL DISTRIBUTION EXPENSES | | 1,202,300 | 1,202,300 | 0 | 0 | 0 |
| 23 | CUSTOMER ACCOUNTING EXPENSES | CUSTACCX | 480,279 | 480,279 | 0 | 0 | 0 |
| 24 | SALES EXPENSES | EXPSALES | 5,629 | 5,172 | 457 | 0 | 457 |
| 25 | ADMINISTRATIVE & GENERAL EXPENSES | LABOR | 89,447 | 82,190 | 7,257 | 0 | 7,257 |
| 26 | SYNERGY SAVINGS | OMEXPX | (619,000) | (563,933) | (55,067) | 0 | (55,067) |
| 27 | TOTAL ADJ EXCL GAS COST & UNCOLL ADJ | | 1,158,071 | 1,205,929 | (47,858) | 0 | (47,858) |
| 28 | TOTAL PRO FORMA OPERATION & MAINT EXP | | 159,649,784 | 21,026,369 | 138,623,415 | 133,114,231 | 5,509,184 |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | DEPRECIATION & AMORT EXPENSE-11 | | | | | | |
| | DEPRECIATION & AMORTIZATION EXPENSE | | | | | | |
| | AMORTIZATION EXPENSE OTHER | | | | | | |
| 1 | 901.1-ORGANIZATION COSTS | PLT901.1 | 0 | 0 | 0 | 0 | 0 |
| 2 | 901.3-MISC INTANGIBLE PLANT | PLT901.3 | (184) | (175) | (9) | 0 | (9) |
| 3 | TOTAL INTANGIBLE PLT RESERVE | | (184) | (175) | (9) | 0 | (9) |
| | DEPRECIATION EXPENSE | | | | | | |
| | PRODUCTION PLANT EXPENSE | | | | | | |
| 4 | 903.1-STRUCTURES & IMPROV | PLT903.1 | 18,630 | 2,310 | 16,320 | 0 | 16,320 |
| 5 | 904.1-PROD EQ PUMPING & REGUL | PLT904.1 | 76,820 | 9,526 | 67,294 | 0 | 67,294 |
| 6 | 904.2-PROD EQ-PEAK SHAVING | PLT904.2 | 55,767 | 6,915 | 48,852 | 0 | 48,852 |
| 7 | 904.3-PROD EQUIP-OTHER | PLT904.3 | 0 | 0 | 0 | 0 | 0 |
| 8 | TOTAL PRODUCTION PLANT | | 151,217 | 18,751 | 132,466 | 0 | 132,466 |
| | DISTRIBUTION PLANT EXPENSE | | | | | | |
| 9 | 903.2-STRUCTURES & IMPROV | PLT903.2 | 12,207 | 12,207 | 0 | 0 | 0 |
| 10 | 905-MAINS | PLT905 | 2,361,562 | 2,361,562 | 0 | 0 | 0 |
| 11 | 907-SERVICES | PLT907 | 3,966,630 | 3,966,630 | 0 | 0 | 0 |
| 12 | 908-METERS | PLT908 | 394,495 | 394,495 | 0 | 0 | 0 |
| 13 | TOTAL DISTRIBUTION PLANT | | 6,734,894 | 6,734,894 | 0 | 0 | 0 |
| | GENERAL PLANT | | | | | | |
| 14 | 903.3-STRUCTURES & IMPROV | PLT903.3 | 13,840 | 12,717 | 1,123 | 0 | 1,123 |
| 15 | 951-COMPUTER EQUIPMENT | PLT951 | 819,090 | 752,639 | 66,451 | 0 | 66,451 |
| 16 | 952-COMMUNICATION EQUIP | PLT952 | 18,516 | 17,014 | 1,502 | 0 | 1,502 |
| 17 | 953-LABORATORY EQUIPMENT | PLT953 | (7,287) | (6,696) | (591) | 0 | (591) |
| 18 | 954-OFFICE FURNITURE & EQUIP | PLT954 | (96,040) | (88,249) | (7,792) | 0 | (7,792) |
| 19 | 955-TRANSPORTATION EQUIPMENT | PLT955 | 135,213 | 124,244 | 10,970 | 0 | 10,970 |
| 20 | 956.1-GENERAL TOOLS & IMPLEM | PLT956 | (2,949) | (2,710) | (239) | 0 | (239) |
| 21 | 956.2-STORES EQUIPMENT | PLT956.2 | 251 | 231 | 20 | 0 | 20 |
| 22 | 956.3-MISCELLANEOUS EQUIP | PLT956.3 | 4,142 | 3,806 | 336 | 0 | 336 |
| 23 | TOTAL GENERAL PLANT | | 884,777 | 812,997 | 71,780 | 0 | 71,780 |
| 24 | TOTAL DEPRECIATION EXPENSE | | 7,770,704 | 7,566,466 | 204,237 | 0 | 204,237 |

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| | OTHER TAXES & OTHER EXP-12 | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | TAXES OTHER THAN INCOME | | | | | | |
| 1 | PROPERTY TAXES | PLANT | 3,577,756 | 3,409,786 | 167,970 | 0 | 167,970 |
| 2 | PAYROLL TAXES | LABOR | 235,235 | 216,151 | 19,084 | 0 | 19,084 |
| 3 | OTHER TAXES | PLANT | (31) | (30) | (1) | 0 | (1) |
| 4 | TOTAL TAXES OTHER THAN INCOME | | 3,812,961 | 3,625,908 | 187,052 | 0 | 187,052 |
| 5 | TOTAL INCOME TAX EXPENSE | | 1,803,600 | 2,566,634 | (763,034) | 0 | (763,034) |
| 6 | TOTAL OPERATING EXPENSES | | 173,037,048 | 34,785,377 | 138,251,671 | 133,114,231 | 5,137,440 |
| 7 | NET OPERATING INCOME | | 7,822,253 | 8,699,833 | (877,581) | 0 | (877,581) |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | DEVELOPMENT OF INCOME TAXES-13 | | | | | | |
| | FEDERAL & STATE TAX CALCULATION | | | | | | |
| 1 | OPERATING REVENUES | | 180,859,301 | 43,485,211 | 137,374,090 | 133,114,231 | 4,259,859 |
| | OPERATING EXPENSES | | | | | | |
| 2 | OPERATION & MAINTENANCE EXP | | 159,649,784 | 21,026,369 | 138,623,415 | 133,114,231 | 5,509,184 |
| 3 | DEPRECIATION | | 7,770,704 | 7,566,466 | 204,237 | 0 | 204,237 |
| 4 | TAXES OTHER THAN INCOME | | 3,812,961 | 3,625,908 | 187,052 | 0 | 187,052 |
| 5 | OPERATING INC BEFORE FED TAXES | | 9,625,853 | 11,266,468 | (1,640,615) | 0 | (1,640,615) |
| | LESS: | | | | | | |
| 6 | INTEREST EXPENSE | PLANT | 5,196,108 | 4,952,160 | 243,949 | 0 | 243,949 |
| 7 | NET OPERATING INC BEFORE TXS | | 4,429,744 | 6,314,308 | (1,884,564) | 0 | (1,884,564) |
| | PERMANENT / FLOW THROUGH DIFF | | | | | | |
| | ADDITIONS: | | | | | | |
| 8 | DISALLOWED TRAVEL & ENT | LABOR | (96) | (88) | (8) | 0 | (8) |
| 9 | PENALTIES & FINES | LABOR | 0 | 0 | 0 | 0 | 0 |
| 10 | LOBBYING EXPENSE | LABOR | 0 | 0 | 0 | 0 | 0 |
| 11 | TOTAL ADDITIONS | | (96) | (88) | (8) | 0 | (8) |
| | DEDUCTIONS: | | | | | | |
| 12 | MEDICARE INCOME | LABOR | (20,938) | (19,239) | (1,699) | 0 | (1,699) |
| 13 | TOTAL DEDUCTIONS | | (20,938) | (19,239) | (1,699) | 0 | (1,699) |
| 14 | TAXABLE BASIS FOR STATE TAXES | | 4,450,586 | 6,333,459 | (1,882,873) | 0 | (1,882,873) |
| 15 | NH STATE TAX EXPENSE @ 8.50% | | 378,300 | 538,344 | (160,044) | 0 | (160,044) |
| 16 | TOTAL STATE TAXES | | 378,300 | 538,344 | (160,044) | 0 | (160,044) |
| 17 | FEDERAL TAXABLE BASIS | | 4,072,286 | 5,795,115 | (1,722,829) | 0 | (1,722,829) |
| 18 | FEDERAL TAXES @ 35% | | 1,425,300 | 2,028,290 | (602,990) | 0 | (602,990) |
| 19 | TOTAL INCOME TAX EXPENSE | | 1,803,600 | 2,566,634 | (763,034) | 0 | (763,034) |
| 20 | NET INCOME AFTER TAX | | 7,822,253 | 8,699,833 | (877,581) | 0 | (877,581) |

| | |
|---|---|
| EFFECTIVE STATE TAX RATE | 8.50% |
| FEDERAL TAX RATE - CURRENT | 35.00% |
| 1 - INCREMENTAL TAX RATE | 0.59475 |
| INCREMENTAL TAX RATE | 0.40525 |
| EFFECTIVE INCREMENTAL FEDERAL RATE | 0.32025 |
| FACTOR FOR TAXABLE BASIS | 1.68138 |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | DEVELOPMENT OF LABOR ALLOCATOR-14 | | | | | | |
| | GAS PRODUCTION LABOR | | | | | | |
| | NATURAL GAS PRODUCTION & GATHERING | | | | | | |
| 1 | OPERATION | PRODOPX | 353,256 | 51,230 | 302,026 | 0 | 302,026 |
| 2 | MAINTENANCE | PRODMNX | 153,113 | 18,986 | 134,127 | 0 | 134,127 |
| 3 | TOTAL NAT GAS PROD & GATHERING | | 506,369 | 70,216 | 436,153 | 0 | 436,153 |
| 4 | OTHER GAS SUPPLY LABOR | GASSUP | 46 | 0 | 46 | 0 | 46 |
| 5 | NATURAL GAS STORAGE LABOR | GASSUP | 1,795 | 0 | 1,795 | 0 | 1,795 |
| | DISTRIBUTION LABOR | | | | | | |
| 6 | DISTRIBUTION OPERATIONS | EXP7612 | 1,598,148 | 1,598,148 | 0 | 0 | 0 |
| 7 | DISTRIBUTION MAINTENANCE | EXP7652 | 2,060,024 | 2,060,024 | 0 | 0 | 0 |
| 8 | TOTAL DISTRIBUTION LABOR | | 3,658,172 | 3,658,172 | 0 | 0 | 0 |
| 9 | CUSTOMER ACCOUNTING LABOR | CUSTACCX | 1,232,442 | 1,232,442 | 0 | 0 | 0 |
| 10 | SALES LABOR | EXPSALES | 556,309 | 511,177 | 45,132 | 0 | 45,132 |
| 11 | ADMINISTRATIVE & GENERAL LABOR | LABOR | 2,503,472 | 2,300,371 | 203,101 | 0 | 203,101 |
| 12 | SUM OF ALLOCATED LABOR EXP | | 8,458,605 | 7,772,378 | 686,227 | 0 | 686,227 |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | ALLOCATION FACTOR TABLE-15 | | | | | | |
| | CAPACITY RELATED | | | | | | |
| | PRODUCTION ALLOCATORS | | | | | | |
| 1 | PRODUCTION DEMAND ALLOC | | 1 | 0 | 1 | 0 | 1 |
| 2 | LPG & LNG PROD ALLOC-PROD | | 100.0000% | 0.0000% | 100 0000% | 0.0000% | 100.0000% |
| 3 | LPG & LNG PROD ALLOC-DISTR | | 100.0000% | 100.0000% | 0.0000% | 0.0000% | 0.0000% |
| 4 | | | | | | | |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | DISTRIBUTION ALLOCATORS | | | | | | |
| 9 | | | | | | | |
| 10 | DISTRIBUTION ALLOCATOR | DISTR | 100.0000% | 100.0000% | 0.0000% | 0.0000% | 0.0000% |
| 11 | | | | | | | |
| 12 | | | | | | | |
| 13 | | | | | | | |
| 14 | | | | | | | |
| 15 | | | | | | | |

ALLOCATION FACTOR TABLE CONT-16

COMMODITY RELATED

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| 1 | PROPANE COMMODITY | ELPG | 1 | 0 | 1 | 0 | 1 |
| 2 | LNG COMMODITY | ELNG | 1 | 0 | 1 | 1 | 0 |
| 3 | ALLOCATED GAS COSTS | GASCOSTS | 1 | 0 | 1 | 1 | 0 |
| 4 | GAS SUPPLY COSTS | GASSUP | 1 | 0 | 1 | 0 | 1 |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | | | | | | | |
| 10 | | | | | | | |

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ALLOCATION FACTOR TABLE CONT-17

CUSTOMER RELATED

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| 1 | ACCT 907-SERVICES | CUST907 | 1 | 1 | 0 | 0 | 0 |
| 2 | ACCT 908-METERS | CUST908 | 1 | 1 | 0 | 0 | 0 |
| 3 | ACCT 909-CUSTOMER PREMISES EQ | CUST909 | 1 | 1 | 0 | 0 | 0 |
| 4 | CUSTOMER DEPOSITS | CUSTDEP | 1 | 1 | 0 | 0 | 0 |
| 5 | ACCT 780-CUS ORD, MET RD & COLL | CUST780 | 1 | 1 | 0 | 0 | 0 |
| 6 | ACCT 781-CUST BILLING & ACCTG | CUST781 | 1 | 1 | 0 | 0 | 0 |
| 7 | RECONNECT FEES | CUSTCONN | 1 | 1 | 0 | 0 | 0 |
| 8 | | | | | | | |
| 9 | | | | | | | |
| 10 | | | | | | | |

NATIONAL GRID NH
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| | INTERNALLY DEVELOPED-18 | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| 1 | TOTAL GAS PLANT IN SERVICE | PLANT | 263,135,986 | 250,782,178 | 12,353,808 | 0 | 12,353,808 |
| 2 | SUM OF ALLOCATED LABOR EXP | LABOR | 8,458,605 | 7,772,378 | 686,227 | 0 | 686,227 |
| 3 | ACCT 903.1-STRUCTURES & IMPROV | PLT903.1 | 1,195,433 | 148,234 | 1,047,199 | 0 | 1,047,199 |
| 4 | ACCT 904.1-PROD EQ PUMP & REG | PLT904.1 | 2,465,980 | 305,781 | 2,160,198 | 0 | 2,160,198 |
| 5 | ACCT 904.2-PROD EQ-PK SHAVING | PLT904.2 | 9,002,322 | 1,116,288 | 7,886,034 | 0 | 7,886,034 |
| 6 | ACCT 904.3-PROD EQUIP-OTHER | PLT904.3 | 0 | 0 | 0 | 0 | 0 |
| 7 | ACCT 904.4-PR EQ-VEHICLE REFUEL | PLT904.4 | 0 | 0 | 0 | 0 | 0 |
| 8 | ACCT 903.2-STRUCTURES & IMPROV | PLT903.2 | 544,322 | 544,322 | 0 | 0 | 0 |
| 9 | ACCT 905-MAINS | PLT905 | 135,833,500 | 135,833,500 | 0 | 0 | 0 |
| 10 | ACCT 907-SERVICES | PLT907 | 80,898,885 | 80,898,885 | 0 | 0 | 0 |
| 11 | ACCT 908-METERS | PLT908 | 21,313,537 | 21,313,537 | 0 | 0 | 0 |
| 12 | ACCT 903.3-STRUCTURES & IMPROV | PLT903.3 | 1,568,455 | 1,441,210 | 127,245 | 0 | 127,245 |
| 13 | ACCT 951-COMPUTER EQUIPMENT | PLT951 | 7,157,593 | 6,576,914 | 580,679 | 0 | 580,679 |
| 14 | ACCT 952-COMMUNICATION EQUIP | PLT952 | 327,188 | 300,644 | 26,544 | 0 | 26,544 |
| 15 | ACCT 953-LABORATORY EQUIPMENT | PLT953 | 383,480 | 352,369 | 31,111 | 0 | 31,111 |
| 16 | ACCT 954-OFFICE FURNITURE & EQ | PLT954 | 140,164 | 128,793 | 11,371 | 0 | 11,371 |
| 17 | ACCT 955-TRANSPORTATION EQUIP | PLT955 | 689,425 | 633,493 | 55,931 | 0 | 55,931 |
| 18 | ACCT 956.1-GEN TOOLS & IMPLEM | PLT956 | 799,663 | 734,788 | 64,875 | 0 | 64,875 |
| 19 | ACCT 956.2-STORES EQUIPMENT | PLT956.2 | 42,888 | 39,409 | 3,479 | 0 | 3,479 |
| 20 | ACCT 956.3-MISCELLANEOUS EQUIP | PLT956.3 | 141,699 | 130,203 | 11,496 | 0 | 11,496 |
| 21 | ACCT 560-LEASEHOLD IMPROV | PLT960 | 0 | 0 | 0 | 0 | 0 |
| 22 | TOTAL DISTRIBUTION PLANT | DISTPLT | 238,788,008 | 238,788,008 | 0 | 0 | 0 |
| 23 | GAS PRODUCTION LABOR | TLABP | 506,369 | 70,216 | 436,153 | 0 | 436,153 |
| 24 | DISTR OPER EXP ACCTS 761 TO 762.2 | EXP7612 | 2,556,340 | 2,556,340 | 0 | 0 | 0 |
| 25 | TOTAL SALES EXPENSES | EXPSALES | 1,680,591 | 1,544,248 | 136,342 | 0 | 136,342 |
| 26 | DISTR MAINT EXP ACCTS 765-772 | EXP7652 | 4,511,324 | 4,511,324 | 0 | 0 | 0 |
| 27 | DISTRIBUTION OPERATING LABOR | TLABDO | 1,598,148 | 1,598,148 | 0 | 0 | 0 |
| 28 | ACCT 780-CUS ORD, MET RG & COLL | EXP780 | 231,135 | 231,135 | 0 | 0 | 0 |
| 29 | ACCT 781-CUST BILLING & ACCTG | EXP781 | 2,292,771 | 2,292,771 | 0 | 0 | 0 |
| 30 | TOTAL GENERAL PLANT | GENPLT | 11,267,103 | 10,353,030 | 914,073 | 0 | 914,073 |
| 31 | PROD EXP EX DIRECT GAS COSTS & SUPER | EXPPRODX | 830,877 | 114,762 | 716,115 | 0 | 716,115 |
| 32 | REVENUES AT CLAIMED RATE OF RETURN | REVCLAIM | 188,708,985 | 49,633,399 | 139,075,586 | 0 | 139,075,586 |
| 33 | ACCT 901.1-ORGANIZATION COSTS | PLT901.1 | 0 | 0 | 0 | 0 | 0 |
| 34 | ACCT 901.3-MISC INTANGIBLE PLANT | PLT901.3 | 23,053 | 21,970 | 1,082 | 0 | 1,082 |
| 35 | ADMIN & GENERAL EXP EXCL ACCT 806 | AGX806 | 8,456,000 | 7,330,234 | 1,125,766 | 0 | 1,125,766 |
| 36 | PRODUCTION OPERATING EXP EXCL GAS | PRODOPX | 558,101 | 80,937 | 477,163 | 0 | 477,163 |
| 37 | PRODUCTION MAINTENANCE EXP | PRODMNX | 272,776 | 33,824 | 238,952 | 0 | 238,952 |
| 38 | CUST ACCTS LABOR EXCL UNCOLL ACCTS | CUSTACCX | 2,523,906 | 2,523,906 | 0 | 0 | 0 |
| 39 | TOT PRO FORM O&M X EXCL GAS & UNCOLL | OMEXPX | 21,753,305 | 19,818,121 | 1,935,184 | 0 | 1,935,184 |
| 40 | | | | | | | |

NATIONAL GRID NH
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| | FIRM GAS SALES REVENUES-19 | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| 1 | FIRM SALES REVENUES | | 178,812,382 | 42,224,238 | 136,588,144 | 133,114,231 | 3,473,913 |
| 2 | GAS COST REVENUES | | 133,114,231 | 0 | 133,114,231 | 133,114,231 | 0 |
| 3 | PRODUCTION & STORAGE MARGIN | | 2,306,405 | 0 | 2,306,405 | 0 | 2,306,405 |
| 4 | BAD DEBT MARGIN | | 1,167,508 | 0 | 1,167,508 | 0 | 1,167,508 |
| 5 | MISCELLANEOUS GAS SUPPLY MARGIN | | 0 | 0 | 0 | 0 | 0 |
| 6 | DISTRIBUTION MARGIN SALES | | 42,224,238 | 42,224,238 | 0 | 0 | 0 |
| | **REVENUE REQUIREMENT INPUTS** | | | | | | |
| 1 | CLAIMED RATE OF RETURN | | 9.26% | 9.26% | 9.26% | 9.26% | 9.26% |
| 2 | PROPOSED SALES REVENUES | | 188,708,985 | 49,633,399 | 139,075,586 | 133,114,231 | 5,961,355 |
| 3 | ANNUAL BOOKED THERM SALES | | 150,369,039 | 150,369,039 | 117,009,709 | 117,009,709 | 117,009,709 |
| 4 | | | | | | | |
| 5 | | | | | | | |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | RATIO TABLE-20 | | | | | | |
| | CAPACITY RELATED | | | | | | |
| | PRODUCTION ALLOCATORS | | | | | | |
| 1 | PRODUCTION DEMAND ALLOC | | 1.00000 | 0.00000 | 1.00000 | 0.00000 | 1.00000 |
| 2 | LPG & LNG PROD ALLOC-PROD | | 1.00000 | 0.00000 | 1.00000 | 0.00000 | 1.00000 |
| 3 | LPG & LNG PROD ALLOC-DISTR | | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 4 | LPG & LNG PROD ALLOCATOR | DPROD | 1.00000 | 0.12400 | 0.87600 | 0.00000 | 0.87600 |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | DISTRIBUTION ALLOCATORS | | | | | | |
| 9 | | | | | | | |
| 10 | DISTRIBUTION ALLOCATOR | DISTR | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 11 | | | | | | | |
| 12 | | | | | | | |
| 13 | | | | | | | |
| 14 | | | | | | | |
| 15 | | | | | | | |

RATIO TABLE CONT-21

COMMODITY RELATED

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| 1 | PROPANE COMMODITY | ELPG | 1.00000 | 0.00000 | 1.00000 | 0.00000 | 1.00000 |
| 2 | LNG COMMODITY | ELNG | 1.00000 | 0.00000 | 1.00000 | 1.00000 | 0.00000 |
| 3 | ALLOCATED GAS COSTS | GASCOSTS | 1.00000 | 0.00000 | 1.00000 | 1.00000 | 0.00000 |
| 4 | GAS SUPPLY COSTS | GASSUP | 1.00000 | 0.00000 | 1.00000 | 0.00000 | 1.00000 |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | | | | | | | |
| 10 | | | | | | | |

| | | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | RATIO TABLE CONT-22 | | | | | | |
| | CUSTOMER RELATED | | | | | | |
| 1 | ACCT 907-SERVICES | CUST907 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 2 | ACCT 908-METERS | CUST908 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 3 | ACCT 909-CUSTOMER PREMISES EQ | CUST909 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 4 | CUSTOMER DEPOSITS | CUSTDEP | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 5 | ACCT 780-CUS ORD, MET RD & COLL | CUST780 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 6 | ACCT 781-CUST BILLING & ACCTG | CUST781 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 7 | RECONNECT FEES | CUSTCONN | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 8 | | | | | | | |
| 9 | | | | | | | |
| 10 | | | | | | | |

| | INTERNALLY DEVELOPED-23 | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| 1 | TOTAL GAS PLANT IN SERVICE | PLANT | 1.00000 | 0.95305 | 0.04695 | 0.00000 | 0.04695 |
| 2 | SUM OF ALLOCATED LABOR EXP | LABOR | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 3 | ACCT 903.1-STRUCTURES & IMPROV | PLT903.1 | 1.00000 | 0.12400 | 0.87600 | 0.00000 | 0.87600 |
| 4 | ACCT 904.1-PROD EQ PUMP & REG | PLT904.1 | 1.00000 | 0.12400 | 0.87600 | 0.00000 | 0.87600 |
| 5 | ACCT 904.2-PROD EQ-PK SHAVING | PLT904.2 | 1.00000 | 0.12400 | 0.87600 | 0.00000 | 0.87600 |
| 6 | ACCT 904.3-PROD EQUIP-OTHER | PLT904.3 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| 7 | ACCT 904.4-PR EQ-VEHICLE REFUEL | PLT904.4 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| 8 | ACCT 903.2-STRUCTURES & IMPROV | PLT903.2 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 9 | ACCT 905-MAINS | PLT905 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 10 | ACCT 907-SERVICES | PLT907 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 11 | ACCT 908-METERS | PLT908 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 12 | ACCT 903.3-STRUCTURES & IMPROV | PLT903.3 | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 13 | ACCT 951-COMPUTER EQUIPMENT | PLT951 | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 14 | ACCT 952-COMMUNICATION EQUIP | PLT952 | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 15 | ACCT 953-LABORATORY EQUIPMENT | PLT953 | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 16 | ACCT 954-OFFICE FURNITURE & EQ | PLT954 | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 17 | ACCT 955-TRANSPORTATION EQUIP | PLT955 | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 18 | ACCT 956.1-GEN TOOLS & IMPLEM | PLT956 | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 19 | ACCT 956.2-STORES EQUIPMENT | PLT956.2 | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 20 | ACCT 956.3-MISCELLANEOUS EQUIP | PLT956.3 | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 21 | ACCT 960-LEASEHOLD IMPROV | PLT960 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| 22 | TOTAL DISTRIBUTION PLANT | DISTPLT | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 23 | GAS PRODUCTION LABOR | TLABP | 1.00000 | 0.13867 | 0.86133 | 0.00000 | 0.86133 |
| 24 | DISTR OPER EXP ACCTS 761 & 762.1 | EXP7612 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 25 | TOTAL SALES EXPENSES | EXPSALES | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 26 | DISTR MAINT EXP ACCTS 765-772 | EXP7652 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 27 | DISTRIBUTION OPERATING LABOR | TLABDO | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 28 | ACCT 780-CUS ORD, MET RG & COLL | EXP780 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 29 | ACCT 781-CUST BILLING & ACCTG | EXP781 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 30 | TOTAL GENERAL PLANT | GENPLT | 1.00000 | 0.91887 | 0.08113 | 0.00000 | 0.08113 |
| 31 | PROD OPER EXP EXCL GAS COSTS | EXPPRODX | 1.00000 | 0.13812 | 0.86188 | 0.00000 | 0.86188 |
| 32 | REVENUES AT CLAIMED RATE OF RETURN | REVCLAIM | 1.00000 | 0.26302 | 0.73698 | 0.00000 | 0.73698 |
| 33 | ACCT 901.1-ORGANIZATION COSTS | PLT901.1 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| 34 | ACCT 901.3-MISC INTANGIBLE PLANT | PLT901.3 | 1.00000 | 0.95305 | 0.04695 | 0.00000 | 0.04695 |
| 35 | ADMIN & GENERAL EXP EXCL ACCT 806 | AGX806 | 1.00000 | 0.86687 | 0.13313 | 0.00000 | 0.13313 |
| 36 | PRODUCTION OPERATING EXP EXCL GAS | PRODOPX | 1.00000 | 0.14502 | 0.85498 | 0.00000 | 0.85498 |
| 37 | PRODUCTION MAINTENANCE EXP | PRODMNX | 1.00000 | 0.12400 | 0.87600 | 0.00000 | 0.87600 |
| 38 | CUST ACCTS LABOR EXCL UNCOLL ACCTS | CUSTACCX | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| 39 | TOT PRO FORM O&M X EXCL GAS & UNCOLL | OMEXPX | 1.00000 | 0.91104 | 0.08896 | 0.00000 | 0.08896 |
| 40 | | | | | | | |

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| | FIRM GAS SALES REVENUES-24 | ALLOC | TOTAL COMPANY Col (2+3) (1)-1 | DELIVERY COSTS (2) | PRODUCTION COSTS (3) | DIRECT GAS COSTS (4) | INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| 1 | FIRM SALES REVENUES | | 1.00000 | 0.23614 | 0.76386 | 0.74444 | 0.01943 |
| 2 | GAS COST REVENUES | | 1.00000 | 0.00000 | 1.00000 | 1.00000 | 0.00000 |
| 3 | PRODUCTION & STORAGE MARGIN | | 1.00000 | 0.00000 | 1.00000 | 0.00000 | 1.00000 |
| 4 | BAD DEBT MARGIN | | 1.00000 | 0.00000 | 1.00000 | 0.00000 | 1.00000 |
| 5 | MISCELLANEOUS GAS SUPPLY MARGIN | | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| 6 | DISTRIBUTION MARGIN SALES | | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |

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| | | ALLOC | LPG & LNG COSTS (1) | MISC PROD COSTS (2) | BAD DEBTS EXCL LPG& LNG (3) | WORKING CAPITAL (4) | TOTAL INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | SUMMARY OF RESULTS PRESENT RATES | | | | | | |
| | RATE BASE | | | | | | |
| 1 | GAS PLANT IN SERVICE | | 12,151,716 | 202,092 | 0 | 0 | 12,353,808 |
| 2 | LESS: DEPREC & AMORT RES | | 8,698,158 | 116,796 | 0 | 0 | 8,814,953 |
| 3 | PLUS: CWIP | | 0 | 0 | 0 | 0 | 0 |
| 4 | NET UTILITY PLANT IN SERVICE | | 3,453,558 | 85,297 | 0 | 0 | 3,538,854 |
| | ADD: | | | | | | |
| 5 | WORKING CAPITAL REQUIREMENTS | | 130,278 | 89,705 | 0 | 4,464,340 | 4,684,323 |
| 6 | PREPAYMENTS | | 7,186 | 120 | 0 | 0 | 7,305 |
| | DEDUCT: | | | | | | |
| 7 | DEFERRED FUEL COSTS | | 0 | 0 | 0 | 0 | 0 |
| 8 | DEFERRED DEMAND SIDE MGMNT COSTS | | 0 | 0 | 0 | 0 | 0 |
| 9 | DEFERRED ENVIORMENTAL COSTS | | 0 | 0 | 0 | 0 | 0 |
| 10 | UNAMORTIZED DEFERRED ASSETS - OTH | | (192,608) | (3,203) | 0 | 0 | (195,812) |
| 11 | ACCUM DEFERRED INCOME TAX | | 1,895,572 | 31,525 | 0 | 0 | 1,927,097 |
| 12 | RATE BASE | | 1,888,057 | 146,799 | 0 | 4,464,340 | 6,499,197 |
| | DEVELOPMENT OF RETURN | | | | | | |
| 13 | TOTAL SALES REVENUE | | 1,146,609 | 791 | 3,340,075 | (1,013,562) | 3,473,913 |
| 14 | OTHER OPERATING REVENUE | | 10,563 | 775,383 | 0 | 0 | 785,946 |
| 15 | TOTAL GAS OPERATING REV | | 1,157,172 | 776,174 | 3,340,075 | (1,013,562) | 4,259,859 |
| | LESS: | | | | | | |
| 16 | PURCHASE GAS COSTS | | 0 | 0 | 0 | 0 | 0 |
| 17 | OTHER OPER & MAINT EXPENSE EXCL UNCOLL | | 1,334,474 | 789,132 | 0 | 0 | 2,123,606 |
| 18 | UNCOLLECTIBLE ACCTS EXPENSE | | 45,503 | 0 | 3,340,075 | 0 | 3,385,578 |
| 19 | DEPRECIATION EXPENSE | | 188,369 | 15,868 | 0 | 0 | 204,237 |
| 20 | OTHER TAXES | | 180,086 | 6,967 | 0 | 0 | 187,052 |
| 21 | INCOME TAXES | | (336,318) | (15,971) | 0 | (410,746) | (763,034) |
| 22 | TOTAL OPERATING EXPENSES | | 1,412,115 | 795,996 | 3,340,075 | (410,746) | 5,137,440 |
| 23 | OPERATING INCOME | | (254,943) | (19,822) | 0 | (602,816) | (877,581) |
| 24 | RATE OF RETURN | | -13.50% | -13.50% | 0.00% | -13.50% | -13.50% |
| 25 | INDEX RATE OF RETURN | | -2.555 | -2.555 | 0.000 | -2.555 | -2.555 |
| 26 | NET REVENUES | | 1,146,609 | 791 | 3,340,075 | (1,013,562) | 3,473,913 |

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| | | ALLOC | LPG & LNG COSTS (1) | MISC PROD COSTS (2) | BAD DEBTS EXCL LPG& LNG (3) | WORKING CAPITAL (4) | TOTAL INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | SUMMARY OF RESULTS CLAIMED RATES-2 | | | | | | |
| | RATE BASE | | | | | | |
| 1 | GAS PLANT IN SERVICE | | 12,151,716 | 202,092 | 0 | 0 | 12,353,808 |
| 2 | LESS: DEPREC & AMORT RES | | 8,698,158 | 116,796 | 0 | 0 | 8,814,953 |
| 3 | PLUS: CWIP | | 0 | 0 | 0 | 0 | 0 |
| 4 | NET UTILITY PLANT IN SERVICE | | 3,453,558 | 85,297 | 0 | 0 | 3,538,854 |
| | ADD: | | | | | | |
| 5 | WORKING CAPITAL REQUIREMENTS | | 130,278 | 89,705 | 0 | 4,464,340 | 4,684,323 |
| 6 | PREPAYMENTS | | 7,186 | 120 | 0 | 0 | 7,305 |
| | DEDUCT: | | | | | | |
| 7 | DEFERRED FUEL COSTS | | 0 | 0 | 0 | 0 | 0 |
| 8 | DEFERRED DEMAND SIDE MGMNT COSTS | | 0 | 0 | 0 | 0 | 0 |
| 9 | DEFERRED ENVIORMENTAL COSTS | | 0 | 0 | 0 | 0 | 0 |
| 10 | UNAMORTIZED DEFERRED ASSETS - OTH | | (192,608) | (3,203) | 0 | 0 | (195,812) |
| 11 | ACCUM DEFERRED INCOME TAX | | 1,895,572 | 31,525 | 0 | 0 | 1,927,097 |
| 12 | RATE BASE | | 1,888,057 | 146,799 | 0 | 4,464,340 | 6,499,197 |
| | DEVELOPMENT OF RETURN | | | | | | |
| 13 | TOTAL SALES REVENUE | | 1,869,226 | 56,975 | 3,340,075 | 695,078 | 5,961,355 |
| 14 | OTHER OPERATING REVENUE | | 10,563 | 775,383 | 0 | 0 | 785,946 |
| 15 | TOTAL GAS OPERATING REV | | 1,879,790 | 832,358 | 3,340,075 | 695,078 | 6,747,301 |
| | LESS: | | | | | | |
| 16 | PURCHASE GAS COSTS | | 0 | 0 | 0 | 0 | 0 |
| 17 | OTHER OPER & MAINT EXPENSE EXCL UNCOLL | | 1,334,474 | 789,132 | 0 | 0 | 2,123,606 |
| 18 | UNCOLLECTIBLE ACCTS EXPENSE | | 45,503 | 0 | 3,340,075 | 0 | 3,385,578 |
| 19 | DEPRECIATION EXPENSE | | 188,369 | 15,868 | 0 | 0 | 204,237 |
| 20 | OTHER TAXES | | 180,086 | 6,967 | 0 | 0 | 187,052 |
| 21 | INCOME TAXES | | (43,477) | 6,798 | 0 | 281,681 | 245,002 |
| 22 | TOTAL OPERATING EXPENSES | | 1,704,956 | 818,765 | 3,340,075 | 281,681 | 6,145,476 |
| 23 | OPERATING INCOME | | 174,834 | 13,594 | 0 | 413,398 | 601,826 |
| 24 | RATE OF RETURN | | 9.26% | 9.26% | 0.00% | 9.26% | 9.26% |
| 25 | INDEX RATE OF RETURN | | 1.000 | 1.000 | 0.000 | 1.000 | 1.000 |
| 26 | NET REVENUES | | 1,869,226 | 56,975 | 3,340,075 | 695,078 | 5,961,355 |

REVENUE REQUIREMENTS-3

| | | ALLOC | LPG & LNG COSTS (1) | MISC PROD COSTS (2) | BAD DEBTS EXCL LPG& LNG (3) | WORKING CAPITAL (4) | TOTAL INDIRECT GAS COSTS (5) |
|---|---|---|---|---|---|---|---|
| | PRESENT RATES | | | | | | |
| 1 | RATE BASE | | 1,888,057 | 146,799 | 0 | 4,464,340 | 6,499,197 |
| 2 | NET OPER INC (PRESENT RATES) | | (254,943) | (19,822) | 0 | (602,816) | (877,581) |
| 3 | RATE OF RETURN (PRES RATES) | | -13.50% | -13.50% | 0.00% | -13.50% | -13.50% |
| 4 | RELATIVE RATE OF RETURN | | -2.555 | -2.555 | 0.000 | -2.555 | -2.555 |
| 5 | SALES REVENUE (PRE RATES) | | 1,146,609 | 791 | 3,340,075 | (1,013,562) | 3,473,913 |
| 6 | ANNUAL BOOKED THERM SALES | | 117,009,709 | 117,009,709 | 117,009,709 | 117,009,709 | 117,009,709 |
| 7 | SALES PRESENT REV ($/THERM) | | $0.0098 | $0.0000 | $0.0285 | -$0.0087 | $0.0297 |
| 8 | NET REVENUES (PRE RATES) | | 1,146,609 | 791 | 3,340,075 | (1,013,562) | 3,473,913 |
| 9 | NET PRESENT REV ($/THERM) | | $0.0098 | $0.0000 | $0.0285 | -$0.0087 | $0.0297 |
| | CLAIMED RATE OF RETURN | | | | | | |
| 10 | CLAIMED RATE OF RETURN | | 9.26% | 0.00% | 9.26% | 9.26% | 0.00% |
| 11 | RETURN REQ FOR CLAIMED ROR | | 174,834 | 13,594 | 0 | 413,398 | 601,826 |
| 12 | SALES REVENUE REQ CLAIMED ROR | | 1,869,226 | 56,975 | 3,340,075 | 695,078 | 5,961,355 |
| 13 | REVENUE DEFICIENCY SALES REV | | 722,618 | 56,185 | 0 | 1,708,640 | 2,487,442 |
| 14 | PERCENT INCREASE REQUIRED | | 63.02% | 7103.03% | 0.00% | -168.58% | 71.60% |
| 15 | ANNUAL BOOKED THERM SALES | | 117,009,709 | 117,009,709 | 117,009,709 | 117,009,709 | 117,009,709 |
| 16 | SALES REV REQUIRED ($/THERM) | | $0.0160 | $0.0005 | $0.0285 | $0.0059 | $0.0509 |
| 17 | REVENUE DEFICIENCY ($/THERM) | | $0.0062 | $0.0005 | $0.0000 | $0.0146 | $0.0213 |
| 18 | NET REVENUES CLAIMED ROR | | 1,869,226 | 56,975 | 3,340,075 | 695,078 | 5,961,355 |
| 19 | NET REV REQUIRED ($/THERM) | | $0.0160 | $0.0005 | $0.0285 | $0.0059 | $0.0509 |

## National Grid NH
## Derivation of Gas Supply Charges - Annual

| | Sales | Gas Supply Revenue Reqm't (ACS) | | | | Allocated Costs of Net Revenue Items | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Therms | Local Production | Purchased Gas & Misc | Total Gas Supply | Direct Gas Costs | LP & LNG | Bad Debts Excl Lp&Lng | Gas Working Capital | Other A&G and Misc. | Total Net Rev Items |
| 1 | 2 | 3 COSS input | 4 =(5)-(3) | 5 COSS Input | 6 COSS Input | 7 COSS Input | 8 COSS Input | 9 COSS Input | 10 =(11)-(7)-(8)-(9) | 11 =(5)-(4) |
| 1 | 117,009,709 | 1,869,226 | 137,206,360 | 139,075,586 | 133,114,231 | 1,869,226 | 3,340,075 | 695,078 | 56,975 | 5,961,355 |

| | |
|---|---|
| Bad Debt Expense | 3,340,075 |
| divided by Direct Gas Costs | 133,114,231 |
| Equal Bad Debt Percentage | **2.509%** |

| | |
|---|---|
| Gas Working Capital Revenue Req | 695,078 |
| divided by Direct Gas Costs | 133,114,231 |
| Equal Gas WC Percentage | **0.522%** |

Table - 1
National Grid - New Hampshire
Marginal Cost Study

**Production Investment Summary-Modified Peaker**

| Line No. | Description | | Company Total |
|---|---|---|---|
| | (1) | | (2) |
| | COST FOR REINFORCEMENT | | |
| 1 | | | |
| 2 | Current Cost of Capacity Expansion | {1} | $1,497.10 |
| 3 | | | |
| 4 | | | |
| 5 | | | |
| 6 | First Year of Capacity Shortfall | {2} | 2009 |
| 7 | | | |
| 8 | | | |
| 9 | Base year of study | | 2006 |
| 10 | | | |
| 11 | | | |
| 12 | Years Before Additions | (6)-(9) | 3 |
| 13 | | | |
| 14 | After Tax Cost of Capital | {3} | 8.57% |
| 15 | Inflation Rate | | 2.50% |
| 16 | | | |
| 17 | | | |
| 18 | | | |
| 19 | Present Worth of Capacity Cost | | |
| 20 | (2)*[1+(15)]^(12)/[1+(14)]^(12) | {4} | $1,259.87 |
| 21 | | | |
| 22 | Percentage Related to Transportation | {5} | 12.4% |
| 23 | | | |
| 24 | **Transportation Related Investment** | (20)*(22) | **$156.47** |
| 25 | | | |
| 26 | **Gas Supply Related Plant Investment** | (20)*[1-(22)] | **$1,103.40** |

NOTES:
1 Source: Table - 1, page 2.
2 Source: Direct Testimony of John Stavrakas, page 3, lines 10-13, NHPSC Docket DG 07-101.
3 Source: Table - 8, page 1.
4 Cost in today's dollars sufficient to purchase the designated unit in the first year of capacity shortfall allowing for interest and price escalation.
5 Source: Table - 1, page 3.

Table - 1
National Grid - New Hampshire
Marginal Cost Study

**Development of Marginal Production Plant Investment**

| Line No. | Description | | | | | Costs |
|---|---|---|---|---|---|---|
| | (1) | | | | | (2) |
| 1 | CONSTRUCTION OF PROPANE PROJECT ALTERNATIVE FACILITY | | | | | |
| 2 | | | | | | |
| 3 | Addition of a New Facility: | | | {1} | | |
| 4 | Storage Tanks | | | | | $8,340,000 |
| 5 | Refrigeration Systems | | | | | 1,970,000 |
| 6 | Delivery Systems | | | | | 4,010,000 |
| 7 | Air Deliver Systems | | | | | 2,560,000 |
| 8 | Air Metering & Regulating (M&R) Station | | | | | 1,370,000 |
| 9 | Pipeline Connection to Project | | | | | 1,000,000 |
| 10 | Pipeline Connection from Project | | | | | 2,500,000 |
| 11 | Land Costs | | | | | 3,520,000 |
| 12 | Indirect Costs | | | | | 5,950,000 |
| 13 | Total Direct Costs | | | | | $31,220,000 |
| 14 | KeySpan Overhead | | | | | 6,650,000 |
| 15 | Total Capital Costs | | | | | $37,870,000 |
| 16 | O&M Costs | | | | | 800,000 |
| 17 | Total Project Costs | | | | | $38,670,000 |
| 18 | Price escalation | {2} | 2.5% | (1) | years | -2.4% |
| 19 | | | | | | |
| 20 | Cost of Facility | | | (17)*[1+(18)] | | $37,726,829 |
| 21 | | | | | | |
| 22 | Total Project Capacity | | | {1} | | 25,200 |
| 23 | | | | | | |
| 24 | Unit Cost of Expansion | | | (20)/(22) | | $1,497.10 |
| 25 | | | | | | |
| 26 | Estimated Reserves for Supplemental Capacity | | | {3} | | 0% |
| 27 | | | | | | |
| 28 | **Adj Cost of Production Capacity, $/Dt** | | | (24)*[1+(26)] | | **$1,497.10** |
| 29 | | | | | | |
| 30 | Percent Transportation-related | | | {4} | | 12.4% |
| 31 | | | | | | |
| 32 | Distribution related | | | (28)*(30) | | $185.94 |
| 33 | Production related | | | (28)-(32) | | $1,311.16 |

NOTES:
1 Source: Exhibit JSS-1, pages 16 & 17, DG 07-101.
2 De-escalation required to restate estimate in test year prices.
3 No allowance employed for planning purposes. Company plans for rating of the plant.

Table - 1
National Grid - New Hampshire
Marginal Cost Study

**Development of Distribution-related Production Plant Investment**

| Line No. | Plant Name | Location | Type | Rating, mscfg | Heat Rate | Hours per Day | Design Day Dt |
|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| 1 | Capacity of Down Stream Assets | | | {1} | | | |
| 2 | | | | | | | |
| 3 | 38 Bridge St | Nashua | LP-Air | 367 | 1,250 | 24 | 11,000 |
| 4 | Temporary Vaporizer | Boscawen | LNG | 25 | 1,050 | 24 | 630 |
| 5 | 130 Elm St | Manchester | LP-Air | 720 | 1,250 | 24 | 21,600 |
| 6 | 130 Elm St | Manchester | LNG | 333 | 1,050 | 24 | 8,400 |
| 7 | Broken Bridge | Concord | LNG | 190 | 1,050 | 24 | 4,800 |
| 8 | Tilton Plant | Tilton | LP-Air | 67 | 1,250 | 24 | 2,000 |
| 9 | Tilton Plant | Tilton | LNG | 381 | 1,050 | 24 | 9,600 |
| 10 | Total | | | 2,083 | 1,161 | | 58,030 |
| 11 | | | | | | | |
| 12 | Production Requirements in lieu of Distribution investments | | | | | | |
| 13 | Output Required for Pressure Support | | | {2} | | | |
| 14 | | | | | | | |
| 15 | | | | | | | |
| 16 | Tilton Plant | Tilton | LNG | 286 | 1,050 | 24 | 7,207 |
| 17 | | Total | | 286 | | | 7,207 |
| 18 | | | | | | | |
| 19 | | | | | | | |
| 20 | Production Allocated to Pressure Support Function | | | | (17)/(10) | 12.4% | |
| 21 | | | | | | | |
| 22 | Production Allocated to Supply Function | | | | 100%-(20) | 87.6% | |
| 23 | | | | | | | |
| 24 | | | | | | | |
| 25 | **Calculation for Design Day Heat Rate** | | | | | | |
| 26 | | | | | MDQ | Heat Rate | |
| 27 | Pipeline and Storage Supplies | | | | 81,333 | 1,026 | |
| 28 | | | | | | | |
| 29 | LNG | | | | 28,166 | 1,050 | |
| 30 | | | | | | | |
| 31 | TOTAL | | | | 109,499 | | |
| 32 | | | | | | | |
| 33 | Heat Rate [(27)*HeatRate+(28)*HeatRate]/(31) | | | | 1,032 | | |

NOTES:

1 Source: Company Distribution Engineering personnel.
2 Source: Table - 2, page 3.

Table - 2
National Grid - New Hampshire
Marginal Cost Study

**Summary of Estimates for Distribution Capacity Cost**

| Line No. | Description | | | Quantity |
|---|---|---|---|---|
| | (1) | | | (2) |
| 1 | | | | |
| 2 | **PROSPECTIVE ADDITIONS** | | | |
| 3 | REINFORCEMENT (From Stoner Analysis) | {1} | | |
| 4 | Estimate of upgrades | | | |
| 5 | to existing facilities. | | $10,077,883 | |
| 6 | Estimated Additional Load, Dt/Design Day | | 33,440 | |
| 7 | Average Cost for Upgrades | (5)/(6) | $301.37 | |
| 8 | Trended Cost for Upgrades | {1} | | $258.70 |
| 9 | | | | |
| 10 | NEW MAIN EXTENSIONS | | | |
| 11 | Unit Cost for New Main Extensions | {2} | | $1,271.60 |
| 12 | | | | |
| 13 | UNIT COSTS | | | |
| 14 | Unit Costs per Design Day Dt for Prospective Additions | | (8) + (11) | $1,530.30 |
| 15 | | | | |
| 16 | **ALTERNATE ANALYSES** | | | |
| 17 | A - HISTORICAL INVESTMENTS | {3} | | |
| 18 | CAPACITY INCREMENT - 1988 to 2006 | | | |
| 19 | 2006 Design Day Sendout | | 116,731 | |
| 20 | 1988 Design Day Sendout | | 83,031 | |
| 21 | Increase in Design Day Sendout | (22)-(21) | | 33,700 |
| 22 | | | | |
| 23 | PLANT INVESTMENTS | | | |
| 24 | Investments to Increase Capacity, Current $'s | | | |
| 25 | Total Investment 1989 | 2006 | | 44,907,846 |
| 26 | | | | |
| 27 | UNIT COST | | | |
| 28 | Avg Unit Cost for Historical Investments | (27)/(23) | | $1,332.58 |
| 29 | | | | |
| 30 | | | | |
| 31 | B - TRENDED COST APPROXIMATION | {4} | | |
| 32 | Trended Cost Approximation (Slope of | | | |
| 33 | Regression Line) | | | $982.87 |
| 34 | | | | |
| 35 | For purposes of further study, assume long run marginal | | | |
| 36 | costs will be estimated by prospective additions, line (14). | | **$1,530.30** /Design Day Dt | |

NOTES:

1. Source: Table - 2, Page 3.
2. Source: Table - 2, Page 4.
3. Source: Cost data from Table - 2, Page 2.
4. Source: Table - 2, Page 5.

Table -2
National Grid - New Hampshire
Marginal Cost Study

Historical Plant Investment Data - Capacity-Related

| Line No. | Description | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | DISTRIBUTION INVESTMENT | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| | PLANT BALANCES | | | | | | | | | | |
| 1 | 1307.6 Distribution System Land | $0 | $60,354 | $74,080 | $131,097 | $133,214 | $143,214 | $143,214 | $195,092 | $196,092 | $197,814 |
| 2 | 1308.6 Distribution Plant Structures | 0 | 400,367 | 416,026 | 390,277 | 396,000 | 398,908 | 401,088 | 392,439 | 410,489 | 432,866 |
| 3 | 1358 Mains | 0 | 38,217,745 | 41,037,109 | 46,730,847 | 49,495,895 | 51,743,320 | 54,299,184 | 56,233,217 | 58,619,137 | 62,326,660 |
| 4 | 1358 Pumping & Regulating Equipment | 0 | 1,343,721 | 1,431,999 | 1,756,702 | 1,903,720 | 2,040,920 | 2,120,307 | 2,247,042 | 2,320,533 | 2,447,355 |
| 5 | | | | | | | | | | | |
| 6 | | | | | | | | | | | |
| 7 | Net Capacity-related | | | | | | | | | | |
| 8 | Distribution Plant | | | | | | | | | | |
| 9 | Balances Sum (1) thru (4) | 0 | 40,020,187 | 43,500,102 | 49,022,923 | 51,929,029 | 54,335,420 | 56,964,393 | 59,075,590 | 61,545,951 | 65,389,823 |
| 10 | | | | | | | | | | | |
| 11 | Net Plant Additions (2) | | | 3,531,915 | 5,402,821 | 2,906,706 | 2,405,790 | 2,628,965 | 2,111,107 | 2,470,301 | 3,853,872 |
| 12 | | | | | | | | | | | |
| 13 | | | | | | | | | | | |
| 14 | Handy-Whitman - Jan 1 | 239 | 253 | 200 | 285 | 295 | 300 | 312 | 333 | 345 | 340 |
| 15 | Index - Mains Jul 1 | 244 | 261 | 203 | 290 | 307 | 309 | 312 | 335 | 348 | 351 |
| 16 | Wtd. Avg. Annual Index | 245.00 | 205.25 | 202.75 | 290.00 | 299.25 | 307.50 | 317.25 | 337.00 | 345.75 | 340.25 |
| 17 | ((14)/4+(15)/2+(14))/4 | | | | | | | | | | |
| 18 | | | | | | | | | | | |
| 19 | Current Cost of Additions | | | | | | | | | | |
| 20 | (11)*(16)/Current Index | $0 | $0 | $4,709,220 | $7,101,067 | $3,661,915 | $2,949,549 | $3,124,097 | $2,361,704 | $2,093,640 | $4,160,085 |
| 21 | | | | | | | | | | | |
| 22 | Cumulative Net Additions | 0 | 0 | 4,709,220 | 11,810,867 | 15,472,003 | 18,422,351 | 21,546,448 | 23,908,233 | 28,601,873 | 30,781,956 |
| 23 | | | | | | | | | | | |
| 24 | Correction Factor for Replm'ts (2) | 51.0% | | | | | | | | | |
| 25 | | | | | | | | | | | |
| 26 | Cum Growth Related Invest | 0 | 0 | 2,443,801 | 6,129,137 | 8,029,450 | 9,560,060 | 11,181,305 | 12,408,929 | 13,804,765 | 15,883,596 |

| Line No. | Description | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | DISTRIBUTION INVESTMENT | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) | (20) |
| | PLANT BALANCES | | | | | | | | | | |
| 1 | 1307.6 Distribution System Land | $197,764 | $197,704 | $197,764 | $197,704 | $197,784 | $197,704 | $197,764 | $197,704 | $197,704 | $197,704 |
| 2 | 1308.6 Distribution Plant Structures | 440,702 | 442,669 | 442,669 | 442,669 | 499,290 | 521,380 | 521,380 | 544,331 | 544,331 | 544,322 |
| 3 | 1358 Mains | 67,701,530 | 72,647,204 | 76,920,478 | 81,138,985 | 93,204,062 | 99,340,539 | 116,503,764 | 122,919,791 | 125,879,287 | 136,231,801 |
| 4 | 1358 Pumping & Regulating Equipment | 2,532,985 | 2,557,081 | 787,819 | 1,036,077 | 1,229,015 | 1,450,602 | 2,253,930 | 2,431,810 | 2,436,538 | 2,473,039 |
| 5 | | | | | | | | | | | |
| 6 | | | | | | | | | | | |
| 7 | Net Capacity-related | | | | | | | | | | |
| 8 | Distribution Plant | | | | | | | | | | |
| 9 | Balances Sum (1) thru (4) | 70,872,901 | 76,044,798 | 78,348,730 | 82,816,295 | 95,190,731 | 101,510,365 | 119,476,846 | 126,093,696 | 128,057,920 | 139,446,866 |
| 10 | | | | | | | | | | | |
| 11 | Net Plant Additions (2) | 5,473,158 | 5,171,817 | 2,303,932 | 4,467,565 | 12,374,436 | 6,319,634 | 17,966,481 | 6,616,850 | 2,004,224 | 10,389,066 |
| 12 | | | | | | | | | | | |
| 13 | | | | | | | | | | | |
| 14 | Handy-Whitman - Jan 1 | 355 | 363 | 370 | 392 | 400 | 408 | 414 | 463 | 595 | 624 |
| 15 | Index - Mains Jul 1 | 360 | 360 | 373 | 396 | 405 | 411 | 414 | 482 | 590 | 635 |
| 16 | Wtd. Avg. Annual Index | 359.50 | 360.25 | 372.00 | 396.00 | 404.50 | 411.00 | 420.25 | 505.50 | 590.75 | 624.75 |
| 17 | ((14)/4+(15)/2+(14))/4 | | | | | | | | | | |
| 18 | | | | | | | | | | | |
| 19 | Current Cost of Additions | | | | | | | | | | |
| 20 | (11)*(16)/Current Index | $5,730,584 | $5,323,618 | $2,303,932 | $4,253,212 | $11,533,158 | $5,796,642 | $15,890,588 | $4,934,822 | $1,663,297 | $6,269,102 |
| 21 | | | | | | | | | | | |
| 22 | Cumulative Net Additions | 36,501,542 | 41,825,160 | 44,129,092 | 48,382,304 | 59,915,462 | 65,712,304 | 81,602,892 | 86,537,714 | 88,401,011 | 94,670,204 |
| 23 | | | | | | | | | | | |
| 24 | Correction Factor for Replm'ts (2) | | | | | | | | | | |
| 25 | | | | | | | | | | | |
| 26 | Cum Growth Related Invest | 18,942,098 | 21,704,732 | 22,900,333 | 25,107,493 | 31,092,506 | 34,100,710 | 42,348,972 | 44,907,846 | 45,874,785 | 49,128,117 |

NOTES:
1 Source: Annual Reports
2 Engineer's estimate

Table - 2
National Grid - New Hampshire
Marginal Cost Study

**Development of Capacity Related Investment - Distribution Reinforcement**

| Line No. | Year | Peak Vol, Dt | Reinf Cost Constant $ | Cumulative Total |
|---|---|---|---|---|
| | (1) | (2) | (3) | (4) |
| 1 | INVESTMENT FOR REINFORCEMENT | {1}{3} | | |
| 2 | 2008 | 155,160 | 3,934,970 | |
| 3 | 2009 | 158,980 | 2,405,595 | 2,405,595 |
| 4 | 2010 | 162,580 | 1,227,790 | 3,633,385 |
| 5 | 2011 | 166,100 | 952,499 | 4,585,884 |
| 6 | 2012 | 169,320 | 1,786,250 | 6,372,134 |
| 7 | 2013 | 172,540 | 807,499 | 7,179,633 |
| 8 | Year 6-10 | 188,600 | 2,898,250 | 10,077,883 |
| 9 | | | | |
| 10 | | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | | | | |
| 14 | Total Reinforcement Cost | 33,440 | $10,077,883 | |
| 15 | | | | |
| 16 | | | | |
| 17 | **REGRESSION RESULTS** | | Cum Invest Col. (4) vs Peak Vol Col. (2) | |
| 18 | Slope | | 259 | |
| 19 | Y Intercept | | (38,188,834) | |
| 20 | Coefficent of Determination (RSQR) | | 95.38% | |
| 21 | t-value | | 9.1 | |
| 22 | | | | |
| 23 | Regression Estimate | (18) | $258.70 | |
| 24 | | | | |
| 25 | Incremental Average Cost | (14), col. (3) / col. (2) | $301.37 | |
| 26 | | | | |
| 27 | UNIT COSTS FOR REINFORCEMENT | | | |
| 28 | $'s per Design Day Dt | {5} | $258.70 | |

NOTES:

1. Baseline forecast used to develop marginal distribution investment taken from engineer's estimates.
2. The design day heat rate is based on expected volumes to flow to firm customers on a design day.
3. Results of Stoner model which identifies pressure problems on design hours. Areas with identified pressure deficiencies are reinforced, based on engineer's assessment of needed improvements. All such cost estimates based on test year costs.
4. Based on weighted average of sources anticipated to be dispatched on a design day and their heat contents. Source: Table 1, Page 3
5. Regression results are sufficiently robust to support the estimate of marginal costs.

Table - 2
National Grid - New Hampshire
Marginal Cost Study

**Development of Distribution Main Extension Investment**

| Line No. | Year | Installed Footage | Cumulative Footage | Cost | Cost per Foot | Cost Index | Costs In 2006 $'s | Costs Per Foot | Cum Investm't | Design Day Demand |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
| | | | | | (3)/(1) | | (3)*(5) | (6)/(1) | | |
| | | {1} | | {2} | | {3} | | | | |
| 1 | 1988 | 162,102 | | | | | | | | |
| 2 | 1989 | 107,669 | 107,669 | 2,102,827 | $19.53 | 1.583 | 3,328,850 | $30.92 | 3,328,850 | 92,038 |
| 3 | 1990 | 76,265 | 183,934 | 1,724,250 | $22.61 | 1.535 | 2,646,836 | $34.71 | 5,975,686 | 94,799 |
| 4 | 1991 | 54,246 | 238,180 | 1,341,529 | $24.73 | 1.492 | 2,002,130 | $36.91 | 7,977,816 | 95,896 |
| 5 | 1992 | 77,355 | 315,535 | 1,489,922 | $19.26 | 1.469 | 2,188,593 | $28.29 | 10,166,409 | 98,274 |
| 6 | 1993 | 62,907 | 378,442 | 1,018,848 | $16.20 | 1.430 | 1,456,788 | $23.16 | 11,623,198 | 101,510 |
| 7 | 1994 | 56,777 | 435,219 | 975,268 | $17.18 | 1.405 | 1,370,167 | $24.13 | 12,993,364 | 102,395 |
| 8 | 1995 | 58,431 | 493,650 | 667,884 | $11.43 | 1.377 | 919,378 | $15.73 | 13,912,742 | 105,007 |
| 9 | 1996 | 83,333 | 576,983 | 1,138,184 | $13.66 | 1.345 | 1,531,108 | $18.37 | 15,443,850 | 107,684 |
| 10 | 1997 | 181,201 | 758,184 | 4,396,282 | $24.26 | 1.315 | 5,782,350 | $31.91 | 21,226,200 | 112,869 |
| 11 | 1998 | 88,330 | 846,514 | 1,792,794 | $20.30 | 1.289 | 2,311,726 | $26.17 | 23,537,926 | 119,052 |
| 12 | 1999 | 183,473 | 1,029,987 | 2,415,815 | $13.17 | 1.265 | 3,055,093 | $16.65 | 26,593,019 | 120,233 |
| 13 | 2000 | 153,120 | 1,183,107 | 3,440,754 | $22.47 | 1.238 | 4,260,095 | $27.82 | 30,853,114 | 128,617 |
| 14 | 2001 | 306,240 | 1,489,347 | 8,588,507 | $28.05 | 1.209 | 10,379,974 | $33.89 | 41,233,088 | 124,000 |
| 15 | 2002 | (179,520) | 1,309,827 | 5,787,927 | ($32.24) | 1.184 | 6,855,040 | ($38.19) | 48,088,128 | 122,483 |
| 16 | 2003 | 359,040 | 1,668,867 | 6,335,289 | $17.65 | 1.164 | 7,375,224 | $20.54 | 55,463,353 | 116,027 |
| 17 | 2004 | 187,889 | 1,856,756 | 2,804,933 | $14.93 | 1.116 | 3,131,704 | $16.67 | 58,595,057 | 128,044 |
| 18 | 2005 | 80,426 | 1,937,182 | 1,761,281 | $21.90 | 1.052 | 1,852,166 | $23.03 | 60,447,223 | 136,000 |
| 19 | 2006 | 61,870 | 1,999,052 | 1,531,679 | $24.76 | 1.000 | 1,531,679 | $24.76 | 61,978,901 | 138,746 |
| 20 | | | | | | | | | | |
| 21 | | | | | | | | | | |
| 22 | | | | | | | | | | |
| 23 | Totals | 2,161,154 | | 49,313,972 | $22.82 | | 61,978,901 | $28.68 | | |
| 24 | | | | | | | | | | |
| 25 | REGRESSION RESULTS | | | | | | | | | |
| 26 | | | | | | | Cumulative Additions col. (8) vs Design Day col. (9) | | | |
| 27 | Slope | | | | | | $1,271.60 | | | |
| 28 | Y Intercept | | | | | | ($116,071,774) | | | |
| 29 | Coefficent of Determination (RSQR) | | | | | | 80.32% | | | |
| 30 | t Statistic | | | | | | 8.1 | | | |
| 31 | | | | | | | | | | |
| 32 | | | | | | | $'s / DDMMBtu | | | |
| 33 | Trended Cost Per Design Day Dt | | | | | | $1,271.60 | | | |
| 34 | | | | | | | | | | |
| 35 | MARGINAL COST ESTIMATES | | | | | | | | | |
| 36 | | | | | | | | | | |
| 37 | Trended Cost Per Design Day Dt | | (27)*(28) | | $1,271.60 | | | | | |
| 38 | | | | | | | | | | |
| 39 | Average Cost Per Design Day Dt | | | | | | | | | |
| 40 | 1988-2006 | | | | $1,326.94 | | | | | |
| 41 | 1997-2006 | | | | $1,574.86 | | | | | |
| 42 | 1989-1996 | | | | $774.32 | | | | | |
| 43 | **Marginal Cost for Main Additions** | | | {4} | **$1,271.60** | | | | | |

NOTES:
1 Source: Total annual new footage installed less footage retired from accounting records. Note that negative amount in 2002 reflect adjustment for prior yea
2 Source: Plant accounting records.
3 Source: Handy Whitman Index of Public Utility Construction Costs.
4 Regression results are sufficiently robust to support the estimate of marginal costs.

Table - 2
National Grid - New Hampshire
Marginal Cost Study

**Regression Analysis of Distribution Capacity Costs**

| Line No. | Year | Total Mains Investment (2006 $) | Mains Investment for Growth (2006 $) | Ratio | Total Capacity Related Net Distribution Investment | Growth Related Distribution Investment | Cumulative Investment | Design Day Sendout |
|---|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| | | {1} | {2} | (2)/(1) | {3} {4} | (3)*(4) | | |
| 1 | 1989 | 5,413,102 | 3,328,850 | 61% | 4,709,220 | 2,895,990 | 2,895,990 | 92,038 |
| 2 | 1990 | 7,831,376 | 2,646,836 | 34% | 7,101,667 | 2,400,210 | 5,296,200 | 94,799 |
| 3 | 1991 | 4,114,685 | 2,002,130 | 49% | 3,661,915 | 1,781,821 | 7,078,021 | 95,896 |
| 4 | 1992 | 3,301,313 | 2,188,593 | 66% | 2,949,549 | 1,955,392 | 9,033,413 | 98,274 |
| 5 | 1993 | 3,814,433 | 1,456,788 | 38% | 3,124,097 | 1,193,139 | 10,226,552 | 101,510 |
| 6 | 1994 | 2,725,577 | 1,370,167 | 50% | 2,361,784 | 1,187,285 | 11,413,837 | 102,395 |
| 7 | 1995 | 3,276,086 | 919,378 | 28% | 2,693,640 | 755,924 | 12,169,761 | 105,007 |
| 8 | 1996 | 4,987,445 | 1,531,108 | 31% | 4,160,085 | 1,277,115 | 13,446,876 | 107,684 |
| 9 | 1997 | 7,069,459 | 5,782,350 | 82% | 5,739,584 | 4,694,601 | 18,141,476 | 112,869 |
| 10 | 1998 | 6,635,216 | 2,311,726 | 35% | 5,323,618 | 1,854,762 | 19,996,239 | 119,052 |
| 11 | 1999 | 5,151,051 | 3,055,093 | 59% | 2,303,932 | 1,366,464 | 21,362,703 | 120,233 |
| 12 | 2000 | 5,223,054 | 4,260,095 | 82% | 4,253,212 | 3,469,060 | 24,831,763 | 128,617 |
| 13 | 2001 | 14,654,234 | 10,379,974 | 71% | 11,533,158 | 8,169,235 | 33,000,998 | 124,000 |
| 14 | 2002 | 7,343,963 | 6,855,040 | 93% | 5,796,842 | 5,410,918 | 38,411,916 | 122,483 |
| 15 | 2003 | 19,980,563 | 7,375,224 | 37% | 15,890,588 | 5,865,533 | 44,277,450 | 116,027 |
| 16 | 2004 | 7,163,486 | 3,131,704 | 44% | 4,934,822 | 2,157,386 | 46,434,835 | 128,044 |
| 17 | 2005 | 3,112,210 | 1,852,166 | 60% | 1,863,297 | 1,108,902 | 47,543,737 | 136,000 |
| 18 | 2006 | 10,352,574 | 1,531,679 | 15% | 6,269,192 | 927,536 | 48,471,273 | 138,746 |
| 19 | | | | | | | | |
| 20 | | | | | | | | |
| 21 | Correction Factor for Replacements {4} | | | 51.9% | | | | |
| 22 | | | | | | | | |
| 23 | | | | | | | | |
| 24 | | | | | | | | |
| 25 | | | | | | | | |
| 26 | | | | | | | | |
| 27 | REGRESSION RESULTS | | | | | Investment col. (6) vs Design Day col. (7) | | |
| 28 | Slope = | | | | | | $982.87 | |
| 29 | Y Intercept = | | | | | | ($86,590,272) | |
| 30 | Coefficent of Determination (RSQR) | | | | | | 80.46% | |
| 31 | t Probability | | | | | | 8.1 | |
| 32 | | | | | | | | |
| 33 | MARGINAL COST ESTIMATES | | | | | | | |
| 34 | Trended Cost Per Design Day Dt | | | | | | $982.87 | |
| 35 | | | | | | | | |
| 36 | Average Cost Per Design Day Dt | | | | | | | |
| 37 | 1989-2006 | | | | | | $1,037.75 | |
| 38 | 1998-2006 | | | | | | $1,445.87 | |
| 39 | 2001-2006 | | | | | | $1,049.12 | |
| 40 | | | | | | | | |
| 41 | | | | | | | | |
| 42 | **Marginal cost estimate (29)*(35) {5}** | | | | $982.87 | | | |

NOTES:
1 Source: Successive Differences in Table 2, page 2, line 3 adjusted by Handy Whitman Index
2 Source: Table 2, Page 4
3 Source: Table - 2, Page 2.
4 Based on the average of the ratios (mains extension investments over mains total investment)
5 This estimate is provided for comparison purposes only. Refer to pages 3 & 4 of this table for the development of a more accurate estimate eliminating the error associated with estimating replacements.

Table - 3
National Grid - New Hampshire
Marginal Cost Study

**Services and Meters Investment**

| Line No. | Description | | Residential ResNonHt R-1 | Residential ResHt R-3&R-4 | Small C&I SmHiW G-41 | Small C&I SmLoW G-51 | Medium C&I MdHiW G-42 | Medium C&I MdLoW G-52 | Large C&I LgHiW G-43 | Large C&I LgLF<90 G-53 | Large C&I LgLF<110 G-54 | Large C&I LgLF>110 G-63 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | (1) | (2) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) |
| 1 | **SERVICE COSTS** | | | | | | | | | | | |
| 2 | | | | | | | | | | | | |
| 3 | | | | | | | | | | | | |
| 4 | Representative Cost | {1} | $2,414 | $2,414 | $2,982 | $2,982 | $7,080 | $7,080 | $8,064 | $8,064 | $15,606 | $15,606 |
| 5 | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | |
| 8 | Services per Customer | (2) | 0.76 | 0.76 | 0.76 | 0.76 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| 9 | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | |
| 12 | **Average Service Cost per Custom** | | **$1,843** | **$1,843** | **$2,276** | **$2,276** | **$7,080** | **$7,080** | **$8,064** | **$8,064** | **$15,606** | **$15,606** |
| 13 | (4)*(8) | | | | | | | | | | | |
| 14 | | | | | | | | | | | | |
| 15 | | | | | | | | | | | | |
| 16 | **METER COSTS** | | | | | | | | | | | |
| 17 | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | |
| 19 | Current Unit Cost for Metering | (3) | $199.48 | $199.48 | $297.62 | $297.62 | $1,143.38 | $1,143.38 | $2,404.54 | $2,404.54 | $10,840.07 | $10,840.07 |
| 20 | | | | | | | | | | | | |
| 21 | | | | | | | | | | | | |
| 22 | | | | | | | | | | | | |
| 23 | | | | | | | | | | | | |
| 24 | | | | | | | | | | | | |
| 25 | | | | | | | | | | | | |
| 26 | Meters per Customer | | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 |
| 27 | | | | | | | | | | | | |
| 28 | | | | | | | | | | | | |
| 29 | | | | | | | | | | | | |
| 30 | **Avg Metering Cost per Customer** | | **$219** | **$219** | **$327** | **$327** | **$1,256** | **$1,256** | **$2,641** | **$2,641** | **$11,905** | **$11,905** |
| 31 | (19)*(26) | | | | | | | | | | | |

NOTES:
1 Source. Typical service costs as estimated by the Engineering Department as 2007 costs including overhead loading.
2 Source: Services per Meter computed by assigning one service to each medium and large C&I customer and computing the ratio of remaining services to the total of residential and small C&I customers.
3 Source: Replacement Cost New Analysis including an allowance for spare meters.

Table - 4
National Grid - New Hampshire
Marginal Cost Study

**Summary of Marginal Commodity Costs**

| Line No. | Description | Residential | | Small C&I | | Medium C&I | | Large C&I | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ResNonHt | ResHt | SmHiW | SmLoW | MdHIW | MdLoW | LgHiW | LgLF<90 | LgLF<110 | LgLF>110 | Company |
| | | R-1 | R-3&R-4 | G-41 | G-51 | G-42 | G-52 | G-43 | G-53 | G-54 | G-63 | |
| | LOAD WEIGHTED MARGINAL COMMODITY | (1) | (2) | (3) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
| 1 | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | |
| 3 | | | | | | | | | | | | |
| 4 | MARGINAL COMMODITY COSTS NOT COMPUTED FOR DISTRIBUTION MARGINAL COST STUDY | | | | | | | | | | | |
| 5 | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | |
| 8 | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | |

Table - 4
National Grid - New Hampshire
Marginal Cost Study

**Development of Capacity Related Production Expense**

| Line No. | Year | Total Capacity Related Expenses | Cost Index | Expense 2006 Dollars | Design Day Sendout, Dt | Average Cost per Design Day Dt |
|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) |
| | | {1} | | | | |
| 1 | 1989 | 1,013,183 | 1.4772 | $1,496,662 | 92,038 | $16.26 |
| 2 | 1990 | 1,203,578 | 1.4223 | 1,711,798 | 94,799 | 18.06 |
| 3 | 1991 | 1,075,515 | 1.3742 | 1,477,961 | 95,896 | 15.41 |
| 4 | 1992 | 1,013,237 | 1.3433 | 1,361,093 | 98,274 | 13.85 |
| 5 | 1993 | 1,075,775 | 1.3130 | 1,412,465 | 101,510 | 13.91 |
| 6 | 1994 | 1,227,075 | 1.2857 | 1,577,596 | 102,395 | 15.41 |
| 7 | 1995 | 1,224,047 | 1.2599 | 1,542,146 | 105,007 | 14.69 |
| 8 | 1996 | 1,266,733 | 1.2364 | 1,566,234 | 107,684 | 14.54 |
| 9 | 1997 | 1,335,709 | 1.2162 | 1,624,482 | 112,869 | 14.39 |
| 10 | 1998 | 1,338,075 | 1.2029 | 1,609,513 | 119,052 | 13.52 |
| 11 | 1999 | 1,152,648 | 1.1857 | 1,366,694 | 120,233 | 11.37 |
| 12 | 2000 | 671,418 | 1.1604 | 779,127 | 128,617 | 6.06 |
| 13 | 2001 | 568,616 | 1.1332 | 644,375 | 124,000 | 5.20 |
| 14 | 2002 | 461,974 | 1.1138 | 514,540 | 122,483 | 4.20 |
| 15 | 2003 | 178,126 | 1.0906 | 194,261 | 116,027 | 1.67 |
| 16 | 2004 | 226,052 | 1.0605 | 239,719 | 128,044 | 1.87 |
| 17 | 2005 | 218,661 | 1.0293 | 225,071 | 136,000 | 1.65 |
| 18 | 2006 | 380,970 | 1.0000 | 380,970 | 138,746 | 2.75 |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | **REGRESSION RESULTS** | | | | Expense (4) | Avg Cost (6) |
| 23 | | | | | vs Demand (5) | vs Year (1) |
| 24 | Slope = | | | | -30.5186 | -1.0301 |
| 25 | Y Intercept = | | | | 4560823 | 2068 |
| 26 | Coefficent of Determination (R**2) | | | | 59.77% | 86.04% |
| 27 | t Value | | | | (4.9) | (9.9) |
| 28 | | | | | | |
| 29 | **MARGINAL COST ESTIMATES** | | | | | |
| 30 | Trended Cost Per Design Day Dt | | | | ($30.52) | |
| 31 | Time Series Predicted Avg Cost (2008*slope)+intercept | | | | | ($0.55) |
| 32 | | | | | | |
| 33 | Average Cost Per Design Day Dt | | | | | |
| 34 | 1989-2006 | | | | | $9.65 |
| 35 | 1998-2006 | | | | | $5.25 |
| 36 | 2002-2006 | | | | | $2.42 |
| 37 | Current Average Cost per Design Day Dt | | | | | $2.75 |
| 38 | | | | | | |
| 39 | Assumed Marginal Cost | | | (35) {2} | | $2.42 |
| 40 | | | | | | |
| 41 | | | | | | |
| 42 | Percentage Related to Transportation | | | | {3} | 12.4% |
| 43 | Transportation Related Investment | | | | (39)*(42) | $0.30 |
| 44 | Gas Supply Related Investment | | | | (39)*[1-(42)] | $2.12 |

NOTES:
1 Source: Booked maintenance expenses for Manufactured Gas, Accounts 1724 & 1725.
2 Post merger 2002-2006 average used for marginal cost.
3 Source: Table - 1, page 3.

Table - 5
National Grid - New Hampshire
Marginal Cost Study

**Development of Capacity Related Expense - T & D**

| Line No. | Year | Capacity Related Expenses | Cost Index | Expense 2006 Dollars | Design Day Sendout | Avg Cost Per Des'n Day Dt |
|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) |
| | | | {2} | | | |
| 1 | 1989 | $1,945,026 | 1.4772 | $2,873,169 | 92,038 | $31.22 |
| 2 | 1990 | 1,893,462 | 1.4223 | 2,692,990 | 94,799 | 28.41 |
| 3 | 1991 | 1,918,550 | 1.3742 | 2,636,450 | 95,896 | 27.49 |
| 4 | 1992 | 2,040,158 | 1.3433 | 2,740,569 | 98,274 | 27.89 |
| 5 | 1993 | 2,151,230 | 1.3130 | 2,824,510 | 101,510 | 27.82 |
| 6 | 1994 | 2,529,506 | 1.2857 | 3,252,074 | 102,395 | 31.76 |
| 7 | 1995 | 2,598,141 | 1.2599 | 3,273,331 | 105,007 | 31.17 |
| 8 | 1996 | 2,558,264 | 1.2364 | 3,163,130 | 107,684 | 29.37 |
| 9 | 1997 | 2,645,969 | 1.2162 | 3,218,013 | 112,869 | 28.51 |
| 10 | 1998 | 2,768,391 | 1.2029 | 3,329,978 | 119,052 | 27.97 |
| 11 | 1999 | 2,626,392 | 1.1857 | 3,114,111 | 120,233 | 25.90 |
| 12 | 2000 | 2,787,674 | 1.1604 | 3,234,872 | 128,617 | 25.15 |
| 13 | 2001 | 2,502,816 | 1.1332 | 2,836,275 | 124,000 | 22.87 |
| 14 | 2002 | 2,228,671 | 1.1138 | 2,482,262 | 122,483 | 20.27 |
| 15 | 2003 | 3,448,665 | 1.0906 | 3,761,043 | 116,027 | 32.42 |
| 16 | 2004 | 3,342,856 | 1.0605 | 3,544,969 | 128,044 | 27.69 |
| 17 | 2005 | 3,654,583 | 1.0293 | 3,761,721 | 136,000 | 27.66 |
| 18 | 2006 | 4,078,867 | 1.0000 | 4,078,867 | 138,746 | 29.40 |

| Line No. | | | |
|---|---|---|---|
| 19 | | | |
| 20 | | | |
| 21 | | | |
| 22 | **REGRESSION RESULTS** | Expense (4) | Avg Cost (6) |
| 23 | | vs Demand (5) | vs Year (1) |
| 24 | Slope = | 19.1510 | -0.1661 |
| 25 | Y Intercept = | 982222 | 360 |
| 26 | Coefficent of Determination (RSQR) | 41.0% | 8.5% |
| 27 | t Statistic | 3.34 | -1.22 |
| 28 | | | |
| 29 | **MARGINAL COST ESTIMATES** | | |
| 30 | Trended Cost Per Design Day Dt | $19.15 | |
| 31 | Time Series Predicted Avg Cost = 2008 * Slope + Intercept | | $26.20 |
| 32 | | | |
| 33 | Average Cost Per Design Day Dt | | |
| 34 | 1989-2006 | | $27.80 |
| 35 | 1997-2006 | | $26.77 |
| 36 | 2002-2006 | | $27.49 |
| 37 | Current Average Cost per Design Day Dt | | $29.40 |
| 38 | | | |
| 39 | **Assumed Marginal Cost {3}** | (34) | $27.49 |

NOTES:
1 Source: Table - 5, Page 2.
2 Source: GNP Implicit Price Deflator.
3 Average costs per DD Dt appear to be relatively stable over time with long term.
Used post merger costs for consistency with capacity related production expense.

Table - 5
National Grid - New Hampshire
Marginal Cost Study

Operations Expense Data - T&D

| Line No. | Acct No. Description | | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) | (20) |
| | TRANS & DIST EXPENSE | [1] | | | | | | | | | | | | | | | | | | |
| 1 | DISTRIBUTION EXPENSE | | | | | | | | | | | | | | | | | | | |
| 2 | OPERATIONS EXPENSE | | | | | | | | | | | | | | | | | | | |
| 3 | 1760 -SUPERINTENDENCE | [2] | 876,635 | 911,187 | 971,390 | 1,008,416 | 1,044,727 | 1,097,982 | 1,140,215 | 1,192,103 | 1,249,414 | 1,302,560 | 1,321,293 | 1,133,716 | 351,830 | 57,284 | 320,464 | 312,197 | 194,191 | 582,811 |
| 4 | 1761 -OPER OF DIST LINES | | 409,455 | 505,545 | 465,317 | 427,244 | 425,732 | 477,794 | 418,145 | 419,195 | 410,571 | 372,897 | 335,345 | 450,144 | 2,201,090 | 1,347,852 | 1,142,303 | 1,309,514 | 994,006 | 744,596 |
| 5 | 1762.1 METER OPERATING LABOR AND EXPENSE | | 560,876 | 528,850 | 531,909 | 518,860 | 472,644 | 455,773 | 367,338 | 312,919 | 350,907 | 377,846 | 520,572 | 564,951 | 794,765 | 617,013 | 578,786 | 762,729 | 1,054,884 | 1,009,092 |
| 6 | 1762.2 OTHER EXPENSE ON CUST PREM | [3] | 1,521,593 | 1,575,073 | 1,593,768 | 1,646,356 | 1,660,222 | 1,667,950 | 1,836,058 | 1,825,448 | 1,659,297 | 1,608,343 | 1,486,526 | 1,241,404 | 730,015 | 509,277 | 328,395 | 137,913 | 28,052 | 108,592 |
| 7 | | | | | | | | | | | | | | | | | | | | |
| 8 | | | | | | | | | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | | | | | | | |
| 14 | Marginal Oper Exp | (3)+(4)+(5) | 1,936,966 | 1,944,682 | 1,969,624 | 1,952,520 | 1,943,103 | 2,031,629 | 1,925,698 | 1,924,217 | 2,010,852 | 2,053,303 | 2,177,210 | 2,157,813 | 3,347,699 | 2,022,949 | 2,041,633 | 2,384,440 | 2,243,081 | 2,316,499 |
| 15 | | | | | | | | | | | | | | | | | | | | |
| 16 | MAINTENANCE | | | | | | | | | | | | | | | | | | | |
| 17 | 1765- MAINTENANCE OF STRUCTURES | | 87,025 | 99,537 | 52,538 | 39,076 | 25,516 | 77,843 | 51,158 | 37,502 | 47,161 | 38,752 | | | 8,504 | 1,277 | 18,671 | 22,753 | 25,340 | 21,010 |
| 18 | 1769- MAINTENANCE OF DISTRIBUTION LINES | | 1,210,020 | 1,134,825 | 1,219,471 | 1,361,653 | 1,465,370 | 1,714,317 | 1,824,935 | 1,752,954 | 1,800,709 | 1,929,672 | 1,653,705 | 1,959,501 | 998,560 | 1,377,884 | 2,543,029 | 2,338,751 | 2,910,168 | 3,260,164 |
| 19 | 1771- MAINT OF SERVICES | | 299,570 | 282,422 | 308,611 | 337,191 | 343,124 | 310,008 | 531,891 | 467,791 | 491,614 | 523,597 | 403,637 | 315,671 | 501,828 | 658,851 | 672,980 | 599,062 | 942,821 | 978,716 |
| 20 | 1772- MAINTENANCE OF CUSTOMER'S METERS | | 154,861 | 154,842 | 166,860 | 205,783 | 235,959 | 239,352 | 164,524 | 121,875 | 141,270 | 124,235 | 107,248 | 91,097 | 106,371 | 110,542 | 217,685 | 234,867 | 147,822 | 150,171 |
| 21 | | | | | | | | | | | | | | | | | | | | |
| 22 | | | | | | | | | | | | | | | | | | | | |
| 23 | | | | | | | | | | | | | | | | | | | | |
| 24 | | | | | | | | | | | | | | | | | | | | |
| 25 | Marginal Maint Exp | (17)+(18)+(19)+(20) | 1,751,476 | 1,671,628 | 1,747,260 | 1,943,703 | 2,069,969 | 2,350,520 | 2,572,508 | 2,400,122 | 2,480,763 | 2,614,256 | 2,444,590 | 2,367,169 | 1,716,269 | 2,148,554 | 3,452,565 | 3,198,033 | 4,026,151 | 4,418,081 |
| 26 | | | | | | | | | | | | | | | | | | | | |
| 27 | MARGINAL T & D Exp & Superintenden | (14)+(25) | 3,688,442 | 3,616,308 | 3,715,904 | 3,896,223 | 4,013,072 | 4,382,049 | 4,498,206 | 4,324,339 | 4,491,715 | 4,667,559 | 4,621,800 | 4,524,982 | 5,063,968 | 4,171,503 | 5,494,198 | 5,580,473 | 6,269,232 | 6,734,560 |
| 28 | | | | | | | | | | | | | | | | | | | | |
| 29 | Allocation of Dist Lines to Customer Component | | | | | | | | | | | | | | | | | | | |
| 30 | Services Investment | | 23,205,608 | 25,730,066 | 28,432,370 | 30,670,769 | 33,199,016 | 35,476,909 | 37,744,390 | 40,038,869 | 42,706,896 | 46,615,422 | 49,171,645 | 54,085,437 | 57,948,787 | 61,018,971 | 66,715,050 | 72,292,215 | 73,756,127 | 80,850,399 |
| 31 | Mains Investment | | 41,637,169 | 46,738,847 | 49,495,895 | 51,743,320 | 54,299,164 | 56,239,217 | 58,619,137 | 62,326,668 | 67,701,530 | 72,847,284 | 76,920,478 | 81,138,985 | 93,264,062 | 99,340,539 | 116,503,764 | 122,919,791 | 125,879,287 | 136,231,861 |
| 32 | Services/(Services+Mains) | (30)/[(30)+(31)] | 35.79% | 35.50% | 36.49% | 37.22% | 37.94% | 38.66% | 39.17% | 39.11% | 38.68% | 39.02% | 39.00% | 39.00% | 39.00% | 39.00% | 39.00% | 39.00% | 39.00% | 39.00% |
| 33 | Customer-related Dist Lines Expense | (32)*(4) | 178,742 | 179,884 | 169,772 | 159,001 | 161,533 | 164,817 | 163,782 | 163,982 | 158,812 | 145,508 | 130,773 | 179,051 | 858,353 | 525,616 | 445,491 | 510,668 | 387,629 | 290,367 |
| 34 | | | | | | | | | | | | | | | | | | | | |
| 35 | Customer Related Allocation of Superintendence Expense | | | | | | | | | | | | | | | | | | | |
| 36 | Cust % | [(5)+(19)+(20)+(33)]/[(27)+(6)-3) | 27.6% | 26.7% | 27.1% | 26.9% | 26.2% | 23.3% | 23.6% | 22.0% | 23.8% | 23.5% | 25.9% | 24.9% | 43.4% | 41.4% | 34.8% | 39.0% | 41.5% | 38.7% |
| 37 | Customer Superintendence | (3)*(31) | 241,553 | 243,530 | 263,535 | 271,074 | 273,848 | 255,511 | 269,473 | 272,249 | 297,332 | 306,743 | 342,874 | 281,839 | 152,659 | 23,699 | 111,574 | 121,729 | 80,601 | 217,616 |
| 38 | | | | | | | | | | | | | | | | | | | | |
| 39 | Customer - Related | | 1,435,602 | 1,387,536 | 1,440,486 | 1,489,908 | 1,487,109 | 1,454,460 | 1,487,008 | 1,358,797 | 1,440,005 | 1,477,929 | 1,585,104 | 1,433,509 | 2,513,977 | 1,936,522 | 2,020,515 | 2,229,653 | 2,613,757 | 2,645,962 |
| 40 | | (5)+(19)+(20)+(33)+(37) | | | | | | | | | | | | | | | | | | |
| 41 | | | | | | | | | | | | | | | | | | | | |
| 42 | Capacity Expenses | | 1,945,026 | 1,893,462 | 1,918,550 | 2,040,168 | 2,161,230 | 2,529,506 | 2,590,141 | 2,558,264 | 2,645,969 | 2,768,391 | 2,620,392 | 2,787,674 | 2,502,816 | 2,228,571 | 3,440,065 | 3,342,856 | 3,654,583 | 4,076,867 |
| 43 | (Other excluding Equip on Cust Premises) | | | | | | | | | | | | | | | | | | | |
| 44 | {27)-(39)-(3)*(6)/[(27)+(6)-(3)] | | | | | | | | | | | | | | | | | | | |

NOTES:
1 Source: Annual Reports
2 Costs in this account are joint between customer and capacity components. Individual component costs are computed by allocating on remaining expenses.
3 Costs in this account are not marginal.

Table - 6
National Grid - New Hampshire
Marginal Cost Study

**Development of Customer-Related Plant Expense**

| Line No. | Year | Services and Meters Expenses | Mains Customer Related Expenses | Total Customer Related Expenses | Cost Index | Expense 2006 Dollars | Annual Customers | Average Cost per Customer |
|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| | | {1} | | (2)+(3) | {2} | (4)*(5) | | (6)/(7) |
| 1 | 1989 | 1,435,602 | 0 | 1,435,602 | 1.4772 | 2,120,655 | 58,809 | $36.06 |
| 2 | 1990 | 1,387,538 | 0 | 1,387,538 | 1.4223 | 1,973,436 | 60,216 | $32.77 |
| 3 | 1991 | 1,440,488 | 0 | 1,440,488 | 1.3742 | 1,979,502 | 60,956 | $32.47 |
| 4 | 1992 | 1,489,908 | 0 | 1,489,908 | 1.3433 | 2,001,412 | 61,725 | $32.42 |
| 5 | 1993 | 1,487,109 | 0 | 1,487,109 | 1.3130 | 1,952,536 | 62,566 | $31.21 |
| 6 | 1994 | 1,454,460 | 0 | 1,454,460 | 1.2857 | 1,869,935 | 64,044 | $29.20 |
| 7 | 1995 | 1,497,008 | 0 | 1,497,008 | 1.2599 | 1,886,042 | 65,385 | $28.85 |
| 8 | 1996 | 1,358,797 | 0 | 1,358,797 | 1.2364 | 1,680,065 | 66,464 | $25.28 |
| 9 | 1997 | 1,440,005 | 0 | 1,440,005 | 1.2162 | 1,751,326 | 67,928 | $25.78 |
| 10 | 1998 | 1,477,929 | 0 | 1,477,929 | 1.2029 | 1,777,737 | 69,588 | $25.55 |
| 11 | 1999 | 1,585,104 | 0 | 1,585,104 | 1.1857 | 1,879,457 | 71,291 | $26.36 |
| 12 | 2000 | 1,433,509 | 0 | 1,433,509 | 1.1604 | 1,663,473 | 73,106 | $22.75 |
| 13 | 2001 | 2,513,977 | 0 | 2,513,977 | 1.1332 | 2,848,923 | 74,959 | $38.01 |
| 14 | 2002 | 1,936,522 | 0 | 1,936,522 | 1.1138 | 2,156,871 | 77,003 | $28.01 |
| 15 | 2003 | 2,026,515 | 0 | 2,026,515 | 1.0906 | 2,210,076 | 77,630 | $28.47 |
| 16 | 2004 | 2,229,653 | 0 | 2,229,653 | 1.0605 | 2,364,459 | 77,630 | $30.46 |
| 17 | 2005 | 2,613,757 | 0 | 2,613,757 | 1.0293 | 2,690,382 | 83,873 | $32.08 |
| 18 | 2006 | 2,645,962 | 0 | 2,645,962 | 1.0000 | 2,645,962 | 84,066 | $31.47 |

| | | | |
|---|---|---|---|
| 19 | | | |
| 20 | | | |
| 21 | | | |
| 22 | | | |
| 23 | | Expense (6) | Unit Cost (8) |
| 24 | REGRESSION RESULTS | vs Customers (7) | vs Year (1) |
| 25 | Slope = | 27.3506 | -0.1575 |
| 26 | Y Intercept = | 170331 | 344 |
| 27 | Coefficent of Determination (RSQR) | 39.1% | 4.6% |
| 28 | t Value | 3.21 | -0.88 |
| 29 | | | |
| 30 | MARGINAL COST ESTIMATES | | |
| 31 | Trended Cost Per Customer | $27.35 | 28.51 |
| 32 | | | |
| 33 | Average Cost Per Customer: | | |
| 34 | 1989-2006 | | $29.79 |
| 35 | 1997-2006 | | $29.04 |
| 36 | 2002-2006 | | $30.15 |
| 37 | Current Average Cost per Customer | | $31.47 |
| 38 | Time Series Test Year Prediction | | $28.19 |
| 39 | | | |
| 40 | **Assumed Marginal Cost {3}** | | **$29.79** |

NOTES:
1 Source: Table - 5, Page 2.
2 Source: GNP Implicit Price Deflator.
3 Regression results for time series are not sufficiently robust for marginal cost estimate. Mean, median, and average of means are within a close range, indicating similar estimates of marginal costs. Employed long term average marginal cost estimate as most representative.

Table - 6
National Grid - New Hampshire
Marginal Cost Study

**Class Weighted Customer Plant Related Expense**

| | ---- Customer Weightings ---- | | | | ------ Customer Weightings ------ | | |
|---|---|---|---|---|---|---|---|
| **Line No.** | **Customer Groups** | **Number of Customers** | **Service & Meter Cost Assigned** | **Total Cost** | **Relative Weight Per Cust** | **System Avg Marginal Cost per Cust** | **Marginal Costs Per Cust** |
| | (1) | (2) {1} | (3) {2} | (4)=(3)*(2) | (5)=(3)/avg(3) {3} | (6) {4} | (7)=(5)*(6) |
| 1 | ResNonHt | 4,975 | $2,062 | 10,259,842 | 0.913 | $29.79 | **$27.19** |
| 2 | ResHt | 67,751 | 2,062 | 139,712,273 | 0.913 | $29.79 | **$27.19** |
| 3 | SmLoS | 7,277 | 2,603 | 18,944,966 | 1.152 | $29.79 | **$34.32** |
| 4 | SmHiS | 1,356 | 2,603 | 3,530,339 | 1.152 | $29.79 | **$34.32** |
| 5 | MdLoS | 1,464 | 8,336 | 12,205,182 | 3.689 | $29.79 | **$109.90** |
| 6 | MdHiS | 300 | 8,336 | 2,498,481 | 3.689 | $29.79 | **$109.90** |
| 7 | LgLoS | 43 | 10,704 | 455,443 | 4.737 | $29.79 | **$141.12** |
| 8 | LgLF<90 | 38 | 10,704 | 410,036 | 4.737 | $29.79 | **$141.12** |
| 9 | LgLF<110 | 1 | 27,510 | 28,351 | 12.175 | $29.79 | **$362.68** |
| 10 | LgLF>110 | 16 | 27,510 | 438,944 | 12.175 | $29.79 | **$362.68** |
| 11 | | | | | | | |
| 12 | | | | | | | |
| 13 | | | | | | | |
| 14 | Total | 83,221 | 74,922 | 188,044,915 | 1.000 | $29.79 | **$29.79** |
| 15 | | | | | | | |
| 16 | Avg Cost per cust | | $2,259.56 | | | | |
| 17 | (4) Total / (2) Total | | | | | | |

NOTES:
1 Source: Company billing records
2 Source: Meters plus services investment from Table - 3 , page 1.
3 Relative weights based on System average = 1.00.
4 Source: Table 6, Page 1.

Table - 6
National Grid - New Hampshire
Marginal Cost Study

**Development of Customer Accounting & Marketing Expense**

| Line No. | Year | Customer Accounting Expenses | Marketing Services Expenses 1786-1788 | Total Customer Related Expenses | Cost Index | Expense in 2006 Dollars | Annual Customers | Average Cost per Customer |
|---|---|---|---|---|---|---|---|---|
| | (1) | (2) {1} | (3) {1} | (4) (2)+(3) | (5) {2} | (6) (4)*(5) | (7) | (8) (6)/(7) |
| 1 | 1989 | 2,358,716 | 505,676 | 2,864,392 | 1.4772 | 4,231,246 | 58,809 | 71.95 |
| 2 | 1990 | 2,708,206 | 733,906 | 3,442,112 | 1.4223 | 4,895,570 | 60,216 | 81.30 |
| 3 | 1991 | 2,779,210 | 785,847 | 3,565,057 | 1.3742 | 4,899,061 | 60,956 | 80.37 |
| 4 | 1992 | 2,906,732 | 833,935 | 3,740,667 | 1.3433 | 5,024,883 | 61,725 | 81.41 |
| 5 | 1993 | 2,943,968 | 1,088,668 | 4,032,636 | 1.3130 | 5,294,748 | 62,566 | 84.63 |
| 6 | 1994 | 2,886,335 | 1,049,296 | 3,935,631 | 1.2857 | 5,059,867 | 64,044 | 79.01 |
| 7 | 1995 | 2,823,394 | 854,466 | 3,677,860 | 1.3207 | 4,857,390 | 65,385 | 74.29 |
| 8 | 1996 | 2,730,030 | 965,699 | 3,695,729 | 1.2364 | 4,569,533 | 66,464 | 68.75 |
| 9 | 1997 | 2,414,940 | 975,279 | 3,390,219 | 1.2162 | 4,123,166 | 67,928 | 60.70 |
| 10 | 1998 | 2,337,755 | 1,039,833 | 3,377,588 | 1.2029 | 4,062,755 | 69,588 | 58.38 |
| 11 | 1999 | 2,235,895 | 1,084,002 | 3,319,897 | 1.1857 | 3,936,399 | 71,291 | 55.22 |
| 12 | 2000 | 2,088,686 | 954,001 | 3,042,687 | 1.1604 | 3,530,795 | 73,106 | 48.30 |
| 13 | 2001 | 855,662 | 462,788 | 1,318,450 | 1.1332 | 1,494,112 | 74,959 | 19.93 |
| 14 | 2002 | 1,060,725 | 54,167 | 1,114,892 | 1.1138 | 1,241,751 | 77,003 | 16.13 |
| 15 | 2003 | 1,966,563 | 374,418 | 2,340,981 | 1.0906 | 2,553,025 | 77,630 | 32.89 |
| 16 | 2004 | 1,980,273 | 1,191,064 | 3,171,337 | 1.0605 | 3,363,079 | 77,630 | 43.32 |
| 17 | 2005 | 2,139,209 | 1,064,874 | 3,204,083 | 1.0293 | 3,298,014 | 83,873 | 39.32 |
| 18 | 2006 | 2,472,634 | 1,658,193 | 4,130,827 | 1.0000 | 4,130,827 | 84,066 | 49.14 |
| 19 | | | | | | | | |
| 20 | | | | | | | | |
| 21 | | | | | | | | |
| 22 | | | | | | | | |
| 23 | | | | | | | | |
| 24 | REGRESSION RESULTS | | | | | Expense (5) | | Unit Cost (8) |
| 25 | | | | | | vs Customers (6) | | vs Year (1) |
| 26 | Slope = | | | | | -98.4453 | | -3.3392 |
| 27 | Y Intercept = | | | | | 10796430 | | 6728 |
| 28 | Coefficent of Determination (RSQR) | | | | | 44.8% | | 68.36% |
| 29 | t Probability | | | | | -3.61 | | -5.88 |
| 30 | | | | | | | | |
| 31 | MARGINAL COST ESTIMATES | | | | | | | |
| 32 | Trended Cost Per Customer | | | | | ($98.45) | | |
| 33 | Time Series predicted Average Cost (2008)*slope+intercept | | | | | | | $22.99 |
| 34 | | | | | | | | |
| 35 | Average Cost Per Customer: | | | | | | | |
| 36 | 1989-2006 | | | | | $56.13 | | |
| 37 | 1997-2006 | | | | | $41.92 | | |
| 38 | 2003-2006 | | | | | $41.29 | | |
| 39 | Current Average Cost per Customer | | | | | $49.14 | | |
| 40 | Average Cost Per Customer 2004-2006: | | | | | $43.95 | | |
| 41 | | | | | | | | |
| 42 | **Assumed Marginal Cost** | | | {3} | | **$41.29** | | |

NOTES:
1 Source: Cost data from Annual Reports, ACCTS 1780, 1781, 1784 excluding Uncollectible Accounts Expense in Account 1783.
2 Source: GNP Implict Price Deflator.
3 Regression results for time series are insufficiently robust for marginal cost, but confirm a declining trend. Therefore, the current average cost over near term, post merger period will be used to estimate the Marginal Cost.

Table - 6
National Grid - New Hampshire
Marginal Cost Study

**Class Weighted Customer Accounting & Marketing Expense**

| Line No. | Customer Groups | Number of Customers | Average Costs Assigned | Average Costs Per Cust | Relative Weight Per Cust | Company Avg Cost per Cust | Marginal Costs Per Cust |
|---|---|---|---|---|---|---|---|
| | (1) | (2) {1} | (3) {1} | (4)= (3)/(2) | (5)=(4)/avg(4) {1}{2} | (6) {3} | (7)= (5)*(6) |
| 1 | ResNonHt | 4,975 | 150,889 | $30.33 | 1.000 | $41.29 | $41.29 |
| 2 | ResHt | 67,751 | 2,054,719 | $30.33 | 1.000 | $41.29 | $41.29 |
| 3 | SmLoS | 7,277 | 220,709 | $30.33 | 1.000 | $41.29 | $41.29 |
| 4 | SmHiS | 1,356 | 41,129 | $30.33 | 1.000 | $41.29 | $41.29 |
| 5 | MdLoS | 1,464 | 44,404 | $30.33 | 1.000 | $41.29 | $41.29 |
| 6 | MdHiS | 300 | 9,090 | $30.33 | 1.000 | $41.29 | $41.29 |
| 7 | LgLoS | 43 | 1,290 | $30.33 | 1.000 | $41.29 | $41.29 |
| 8 | LgLF<90 | 38 | 1,162 | $30.33 | 1.000 | $41.29 | $41.29 |
| 9 | LgLF<110 | 1 | 31 | $30.33 | 1.000 | $41.29 | $41.29 |
| 10 | LgLF>110 | 16 | 484 | $30.33 | 1.000 | $41.29 | $41.29 |
| 11 | | | | | | | |
| 12 | | | | | | | |
| 13 | | | | | | | |
| 14 | Total | 83,221 | 2,523,907 | $30.33 | 0.735 | $41.29 | $41.29 |

NOTES:
1 Customer class weighting factors were developed from 06/30/07 Accounting Cost of Service Study based on the total of all test year costs in these accounts without uncollectibles.
2 Relative weights based on System average = 1.00.
3 Source: Table 6, Page 3.

Table - 6
National Grid - New Hampshire
Marginal Cost Study

**Class Weighted Uncollectible Accounts Expense**

| Line No. | Customer Groups | | Test Year Uncollectible Accounts Exp | Adjusted Uncoll. Accts. Exp. | Test Year Revenues | Write-off Percentage |
|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) |
| | | | (1) | (1) | (1) | (6)=(4)/(5) |
| 1 | ResNonHt | | $61,890 | $107,333 | $1,982,210 | 5.41% |
| 2 | ResHt | | 2,275,953 | 3,947,113 | 88,585,221 | 4.46% |
| 3 | SmLoS | | 111,027 | 192,551 | 25,970,102 | 0.74% |
| 4 | SmHiS | | 23,900 | 41,449 | 5,195,053 | 0.80% |
| 5 | MdLoS | | 47,911 | 83,090 | 36,290,680 | 0.23% |
| 6 | MdHiS | | 5,643 | 9,786 | 7,068,558 | 0.14% |
| 7 | LgLoS | | 0 | 0 | 4,072,019 | 0.00% |
| 8 | LgLF<90 | | 0 | 0 | 2,174,374 | 0.00% |
| 9 | LgLF<110 | | 0 | 0 | 25,129 | 0.00% |
| 10 | LgLF>110 | | 0 | 0 | 1,129,676 | 0.00% |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | Total | | $2,526,324 | 4,381,323 | $172,493,022 | 2.54% |
| 15 | Adjusted Pro forma writeoff rate | | | | 2.54% | |

NOTES:
1 Uncollectible expense by class allocated to classes based upon percentage of class gross writeoffs proportions.

Table - 7
National Grid - New Hampshire
Marginal Cost Study

Development of A & G Loading Factors

| Line No. | Description | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Nonplant Related Expenses | | | | | | | | | |
| 2 | 1790 Data Processing | 1,221,330 | 1,268,573 | 1,213,411 | 1,148,132 | 1,108,635 | 1,152,448 | 1,120,023 | 1,216,082 | 1,251,609 |
| 3 | 1791 General Office Salaries | 1,591,407 | 1,607,337 | 1,637,784 | 1,710,938 | 1,721,760 | 1,781,241 | 1,791,207 | 1,876,303 | 1,745,863 |
| 4 | 1793 Office Supplies | 278,118 | 315,340 | 323,298 | 318,817 | 349,060 | 347,560 | 332,022 | 353,650 | 324,191 |
| 5 | 1794 Super. Fees & Spec Servs | 603,729 | 629,173 | 702,307 | 769,761 | 718,935 | 839,542 | 670,272 | 625,714 | 558,649 |
| 6 | 1799 Injury & Damages | 1,803 | 953 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | 1800 Employee Welfare & Relief | 203,570 | 186,696 | 253,807 | 135,711 | 145,458 | 67,700 | 131,950 | 126,335 | 123,090 |
| 8 | 1801 Misc Gen Exp | 635,012 | 542,610 | 617,446 | 662,680 | 657,151 | 654,017 | 577,760 | 640,250 | 664,357 |
| 9 | 1807 Duplicate Misc Charges | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | | | | | | | | | | |
| 11 | | | | | | | | | | |
| 12 | Taxes other than Income | 1,295,017 | 1,464,186 | 1,454,199 | 1,560,416 | 1,610,506 | 1,600,652 | 942,578 | 670,003 | 855,403 |
| 13 | Total Non-Plant | 4,688,656 | 4,648,295 | 5,048,920 | 5,159,323 | 5,202,870 | 5,310,712 | 4,445,789 | 4,492,265 | 4,291,563 |
| 14 | | | | | | | | | | |
| 15 | Plant Related Expenses | | | | | | | | | |
| 16 | | | | | | | | | | |
| 17 | | | | | | | | | | |
| 18 | 1797 Regulatory Exp | 24,430 | 111,342 | 101,766 | 78,877 | 130,058 | 46,822 | 38,180 | 99,259 | 93,331 |
| 19 | 1799 Property Ins | 923,310 | 927,329 | 919,562 | 944,954 | 910,246 | 936,439 | 807,797 | 899,988 | 896,372 |
| 20 | 1802 Gen Plt Maint | 56,489 | 58,952 | 69,539 | 85,434 | 85,756 | 91,728 | 88,022 | 91,404 | 94,033 |
| 21 | 1803 Rents | 360,011 | 331,631 | 336,945 | 326,547 | 319,938 | 267,824 | 266,573 | 315,189 | 338,457 |
| 22 | Total Plant Related Expenses | $1,364,240 | $1,429,254 | $1,427,802 | $1,435,822 | $1,445,997 | $1,342,813 | $1,200,572 | $1,405,850 | $1,422,193 |
| 23 | | | | | | | | | | |
| 24 | Total Allocable O&M (Total O&M less non-labor production | | | | | | | | | |
| 25 | costs and A&G expenses) | 10,604,454 | 11,525,784 | 11,687,219 | 11,850,450 | 12,424,389 | 13,150,168 | 12,609,283 | 12,467,597 | 12,375,290 |
| 26 | | | | | | | | | | |
| 27 | A & G Loading Factor Nonplant Rel Exp | | | | | | | | | |
| 28 | Line (13)/(25) | 44.21% | 40.33% | 43.57% | 43.54% | 41.88% | 40.39% | 35.26% | 36.03% | 34.68% |
| 29 | Average 2003 - 2006 = 64.11% | | | | | | | | | |
| 30 | | | | | | | | | | |
| 31 | | | | | | | | | | |
| 32 | Total Gross Plant $ | 90,119,098 | 99,467,339 | 106,202,255 | 112,423,806 | 118,658,821 | 124,120,097 | 129,472,654 | 135,806,318 | 145,866,420 |
| 33 | | | | | | | | | | |
| 34 | | | | | | | | | | |
| 35 | A & G Loading Factor Plant Rel Exp | | | | | | | | | |
| 36 | Line (22)/(32) | 1.51% | 1.44% | 1.34% | 1.28% | 1.22% | 1.08% | 0.93% | 1.04% | 0.97% |
| 37 | Average 2003 - 2006 = 0.22% | | | | | | | | | |

| Line No. | Description | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Nonplant Related Expenses | | | | | | | | | |
| 2 | 1790 Data Processing | 1,211,703 | 1,297,657 | 939,758 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | 1791 General Office Salaries | 1,729,686 | 2,014,845 | 2,046,463 | 153,735 | 2,032,950 | 2,785,081 | 3,138,934 | 2,858,060 | 3,704,184 |
| 4 | 1793 Office Supplies | 330,734 | 348,346 | 476,545 | 128,028 | 2,987,475 | 2,054,161 | 1,446,136 | 1,317,507 | 1,265,686 |
| 5 | 1794 Super. Fees & Spec Servs | 567,459 | 580,687 | 523,092 | 259,214 | 169,163 | 499,379 | 930,684 | 563,279 | 560,762 |
| 6 | 1799 Injury & Damages | 0 | 0 | 116,869 | 389,048 | 1,026 | 25,580 | 108,423 | 131,959 | 120,049 |
| 7 | 1800 Employee Welfare & Relief | 131,238 | 124,465 | 609,196 | 1,665,715 | 1,792,716 | 1,734,467 | 2,722,240 | 2,414,329 | 2,324,499 |
| 8 | 1801 Misc Gen Exp | 767,033 | 628,965 | 852,389 | 6,054,082 | (38,334) | 45,411 | 180,962 | (160,605) | 68,997 |
| 9 | 1807 Duplicate Misc Charges | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | | | | | | | | | | |
| 11 | | | | | | | | | | |
| 12 | Taxes other than Income | 892,557 | 992,232 | N/A | 436,190 | 249,220 | 313,602 | 225,922 | 115,583 | 210,517 |
| 13 | Total Non-Plant | 4,408,707 | 4,889,642 | 4,553,554 | 11,088,012 | 7,994,296 | 7,457,697 | 8,753,301 | 7,330,032 | 8,274,594 |
| 14 | | | | | | | | | | |
| 15 | Plant Related Expenses | | | | | | | | | |
| 16 | | | | | | | | | | |
| 17 | | | | | | | | | | |
| 18 | 1797 Regulatory Exp | 22,670 | 26,354 | 24,256 | 290,765 | 276,670 | 332,004 | 332,004 | 608,709 | 622,287 |
| 19 | 1799 Property Ins | 875,967 | 878,375 | 1,017,636 | 709,968 | 850,716 | 75,865 | 69,442 | 77,906 | 74,278 |
| 20 | 1802 Gen Plt Maint | 67,825 | 264,594 | 298,187 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | 1803 Rents | 344,628 | 454,772 | 868,951 | 0 | 0 | 5,893 | 0 | 0 | 0 |
| 22 | Total Plant Related Expenses | $1,311,090 | $1,624,095 | $2,209,040 | $1,000,753 | $1,127,386 | $413,762 | $401,446 | $685,615 | $696,565 |
| 23 | | | | | | | | | | |
| 24 | Total Allocable O&M (Total O&M less non-labor production | | | | | | | | | |
| 25 | costs and A&G expenses) | 12,463,871 | 11,869,517 | 10,734,412 | 8,843,331 | 8,413,769 | 10,311,527 | 11,145,574 | 15,427,721 | 14,251,758 |
| 26 | | | | | | | | | | |
| 27 | A & G Loading Factor Nonplant Rel Exp | | | | | | | | | |
| 28 | Line (13)/(25) | 35.37% | 41.19% | 43.35% | 125.38% | 95.01% | 72.32% | 78.54% | 47.51% | 58.06% |
| 29 | Average 2003 - 2006 = 64.11% | | | | | | | | | |
| 30 | | | | | | | | | | |
| 31 | | | | | | | | | | |
| 32 | Total Gross Plant $ | 156,424,246 | 166,682,099 | 174,018,261 | 189,353,169 | 202,252,941 | 227,692,187 | 239,474,278 | 242,115,491 | 263,405,595 |
| 33 | | | | | | | | | | |
| 34 | | | | | | | | | | |
| 35 | A & G Loading Factor Plant Rel Exp | | | | | | | | | |
| 36 | Line (22)/(32) | 0.84% | 0.97% | 1.27% | 0.53% | 0.56% | 0.10% | 0.17% | 0.28% | 0.26% |
| 37 | Average 2003 - 2006 = 0.22% | | | | | | | | | |

NOTES:
1 Source: Annual Reports

Table - 7
National Grid - New Hampshire
Marginal Cost Study

Development of Miscellaneous Loading Factors

| Line No. | Description | | | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Materials and Supplies and Prepayments Loader** | | | | | | | | | | | |
| 2 | Materials and Supplies | | | 5,171,473 | 5,150,104 | 6,093,787 | 9,034,208 | 10,148,000 | 9,443,873 | 9,337,258 | 10,278,497 | 10,570,101 |
| 3 | Fuel Inventory (Included above) | | | 3,443,323 | 4,124,553 | 4,106,243 | 8,118,086 | 8,623,309 | 7,903,225 | 7,899,072 | 8,825,292 | 8,029,160 |
| 4 | Prepayments | | | 1,901,113 | 1,178,094 | 1,135,297 | 1,195,252 | 1,266,591 | 1,062,916 | 1,155,521 | 1,097,855 | 1,083,594 |
| 5 | Fuel Related Prepayments | | | 0 | 3,990 | 0 | 21,226 | 0 | 0 | 0 | 0 | 0 |
| 6 | Total Utility Plant | | | 90,119,038 | 99,467,333 | 109,202,255 | 112,423,808 | 118,856,821 | 124,120,097 | 129,472,654 | 135,808,318 | 145,888,429 |
| 7 | | | | | | | | | | | | |
| 8 | Non-Fuel Loader | (2-3+4-5)/(6) | (1) | 4.03% | 2.62% | 2.00% | 2.54% | 2.45% | 2.10% | 2.05% | 1.08% | 1.08% |
| 9 | Average 2003 - 2006 = 0.11% | | | | | | | | | | | |
| 10 | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | |
| 13 | **General Plant Loading Factor** | | | | | | | | | | | |
| 14 | Total General Plant | | | 5,933,582 | 6,503,724 | 8,819,445 | 7,859,250 | 7,970,207 | 8,384,740 | 8,221,795 | 8,870,155 | 9,203,222 |
| 15 | Total Utility Plant | | | 90,119,098 | 99,467,339 | 109,202,255 | 112,423,808 | 110,650,071 | 124,120,097 | 129,472,654 | 135,808,318 | 145,888,429 |
| 16 | | | | | | | | | | | | |
| 17 | Gen Plant Factor | (14)/(15-14 | (1) | 7.05% | 7.00% | 8.89% | 7.31% | 7.20% | 7.24% | 6.78% | 6.99% | 6.73% |
| 18 | Average 2003 - 2006 = 4.71% | | | | | | | | | | | |
| 19 | | | | | | | | | | | | |
| 20 | | | | | | | | | | | | |
| 21 | | | | | | | | | | | | |
| 22 | **Loss Factor** | | | | | | | | | | | |
| 23 | Total Sendout | | | 96,483,220 | 85,553,890 | 89,607,210 | 101,241,230 | 103,028,460 | 108,632,770 | 105,689,400 | 113,109,580 | 117,213,840 |
| 24 | Total Sales | | | 94,350,580 | 83,671,500 | 87,600,130 | 99,013,973 | 100,759,878 | 106,233,069 | 103,125,470 | 113,132,820 | 113,898,470 |
| 25 | | | | | | | | | | | | |
| 26 | Loss Factor | (24)/(23) | | 97.80% | 97.80% | 97.80% | 97.80% | 97.80% | 97.80% | 97.57% | 99.97% | 97.17% |
| 27 | Average 1989 - 2005 = 97.75% | | | | | | | | | | | |

| Line No. | Description | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Materials and Supplies and Prepayments Loader** | | | | | | | | | |
| 2 | Materials and Supplies | 10,880,994 | 10,988,004 | 8,252,710 | 9,726,073 | 6,029,583 | 12,264,678 | 14,721,037 | 10,472,896 | 20,753,310 |
| 3 | Fuel Inventory (Included above) | 8,478,900 | 8,482,507 | 7,103,702 | 8,026,722 | 6,141,037 | 12,252,947 | 14,714,003 | 10,472,896 | 20,753,370 |
| 4 | Prepayments | 940,831 | 987,408 | 835,892 | 623,852 | (349) | 800 | 83,606 | 404,721 | 570,700 |
| 5 | Fuel Related Prepayments | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | Total Utility Plant | 156,474,246 | 166,682,099 | 174,018,261 | 189,363,183 | 202,252,941 | 227,892,187 | 233,474,276 | 242,115,491 | 263,405,595 |
| 7 | | | | | | | | | | |
| 8 | Non-Fuel Loader (2-3+4-5)/(6) (1) | 1.50% | 1.49% | 0.97% | 0.75% | 0.34% | 0.01% | 0.01% | 0.19% | 0.22% |
| 9 | Average 2003 - 2006 = 0.11% | | | | | | | | | |
| 10 | | | | | | | | | | |
| 11 | | | | | | | | | | |
| 12 | | | | | | | | | | |
| 13 | **General Plant Loading Factor** | | | | | | | | | |
| 14 | Total General Plant | 9,478,301 | 11,244,509 | 7,255,965 | 8,348,012 | 11,173,887 | 11,502,170 | 10,499,392 | 10,220,842 | 11,333,343 |
| 15 | Total Utility Plant | 156,424,246 | 186,682,099 | 174,018,201 | 189,363,169 | 202,252,941 | 227,892,187 | 233,474,276 | 242,115,491 | 263,405,595 |
| 16 | | | | | | | | | | |
| 17 | Gen Plant Factor (14)/(15-14 (1) | 6.45% | 7.23% | 4.35% | 4.61% | 5.85% | 5.30% | 4.59% | 4.41% | 4.50% |
| 18 | Average 2003 - 2006 = 4.71% | | | | | | | | | |
| 19 | | | | | | | | | | |
| 20 | | | | | | | | | | |
| 21 | | | | | | | | | | |
| 22 | **Loss Factor** | | | | | | | | | |
| 23 | Total Sendout | 112,364,220 | 123,050,330 | 116,295,192 | 139,040,020 | 145,107,650 | 154,661,050 | 149,609,900 | 147,633,850 | 136,710,840 |
| 24 | Total Sales | 111,015,990 | 116,256,180 | 114,313,111 | 133,840,570 | 139,004,002 | 152,089,230 | 144,710,270 | 143,418,858 | 136,789,736 |
| 25 | | | | | | | | | | |
| 26 | Loss Factor (24)/(23) | 98.80% | 94.48% | 98.30% | 96.30% | 95.79% | 98.40% | 96.73% | 97.14% | 100.06% |
| 27 | Average 1989 - 2005 = 97.75% | | | | | | | | | |

NOTES:
1 Used post merger data for Materials & Supplies and General Plant loading factors to eliminate effect of changes in accounting and recording overheads.
2 Loss factor has remained stable for entire study period.

Table - 8
National Grid - New Hampshire
Marginal Cost Study

**Summary of Levelized Fixed Charge Rates**

| Line No. | Description | | Engineer's Fixed Charge Rate | Economist's Fixed Charge Rate |
|---|---|---|---|---|
| | (1) | | (2) | (3) |
| 1 | FIXED CHARGE RATE RESULTS | | | |
| 2 | | | | Over |
| 3 | Levelized Cost for: | {1} | | Book Life |
| 4 | Production Plant | | 14.01% | 10.95% |
| 5 | Mains (Cap-related Dist) | | 13.42% | 9.63% |
| 6 | Services Investment | | 13.28% | 9.96% |
| 7 | Meters Investment | | 13.74% | 10.50% |
| 8 | | | | |
| 9 | | | | |
| 10 | INCREMENTAL COST OF CAPITAL | {2} | | |
| 11 | Debt | | 9.20% | 50.00% |
| 12 | Preferred | | 0.00% | 0.00% |
| 13 | Common | | 11.50% | 50.00% |
| 14 | Other | | 0.00% | 0.00% |
| 15 | Weighted Cost of Incremental Capital | | | 10.35% |
| 16 | | | | |
| 17 | | | | |
| 18 | After Tax Cost of New Capital | {3} | | 8.57% |
| 19 | Incremental Tax Rate | {4} | | 38.76% |
| 20 | Tax Effected Cost of Capital | {5} | | 14.27% |
| 21 | Property Tax Rate | {6} | | 2.11% |
| 22 | Gross Receipts Tax Rate | {7} | | 0.00% |
| 23 | Inflation Rate | {8} | | 2.57% |
| 24 | Property Tax Escalation Rate | {8} | | 2.57% |
| 25 | Commodity Escalation Rate | {9} | | 3.00% |

NOTES:
1 Source: Table - 8, pages 3, 4, 5, & 6.
2 Weighted average current cost of raising capital in 2006.
3 Wtd Cost of Capital (15) less tax savings on debt interest.
4 Incremental tax rate assumed to be 35% Federal and 7% State tax which results in a combined effective rate of 40.52%.
5 Tax effected cost of capital, (15) plus tax component on return.
6 Current composite average tax rate.
7 The state's 1.01% franchise tax is excluded since it is surcharged.
8 Inflation rate estimated for the forward looking five year period.
9 Commodity price escalation factor asumed by MAC.

Table - 8
National Grid - New Hampshire
Marginal Cost Study
**LEVELIZED FIXED CHARGE ANALYSIS Rev. 4.0.0**
**INPUT DATA**

| LINE NO. | VARIABLE | Peaking Plant | Capacity - Related Distribution | Services | Meters |
|---|---|---|---|---|---|
| 1 | Plant Data | 30 | 0 | 0 | 40 |
| 2 | | | | | |
| 3 | CAPITALIZED COST | $1,000 | $1,000 | $1,000 | $1,000 |
| 4 | BOOK LIFE | 30 | 59 | 40 | 35 |
| 5 | SALVAGE VALUE | 0% | -15% | -70% | 0% |
| 6 | MACRS LIFE | 20 | 20 | 20 | 20 |
| 7 | | | | | |
| 8 | | | | | |
| 9 | Capital Structure | | | | |
| 10 | | | | | |
| 11 | DEBT RATIO | 50.00% | 50.00% | 50.00% | 50.00% |
| 12 | PREFERRED RATIO | 0.00% | 0.00% | 0.00% | 0.00% |
| 13 | COMMON RATIO | 50.00% | 50.00% | 50.00% | 50.00% |
| 14 | OTHER ____________ | 0.00% | 0.00% | 0.00% | 0.00% |
| 15 | | | | | |
| 16 | Cost of Capital | | | | |
| 17 | | | | | |
| 18 | DEBT COST | 9.20% | 9.20% | 9.20% | 9.20% |
| 19 | PREFERRED COST | 0.00% | 0.00% | 0.00% | 0.00% |
| 20 | COMMON COST | 11.50% | 11.50% | 11.50% | 11.50% |
| 21 | OTHER | 0.00% | 0.00% | 0.00% | 0.00% |
| 22 | WTD COST OF CAPITAL | 10.35% | 10.35% | 10.35% | 10.35% |
| 23 | AFTER TAX COST / CAP | 8.49% | 8.49% | 8.49% | 8.49% |
| 24 | | | | | |
| 25 | Tax Data | | | | |
| 26 | | | | | |
| 27 | TAX RATE | 40.52% | 40.52% | 40.52% | 40.52% |
| 28 | ITC RATE | 0.00% | 0.00% | 0.00% | 0.00% |
| 29 | REVENUE TAX RATE | 0.00% | 0.00% | 0.00% | 0.00% |
| 30 | PROPERTY TAX RATE | 2.11% | 2.11% | 2.11% | 2.11% |
| 31 | PROPERTY INSURANCE | 0.00% | 0.00% | 0.00% | 0.00% |
| 32 | PROPERTY TAX BASIS | 2 | 2 | 2 | 2 |
| 33 | 1 = Original Cost | | | | |
| 34 | 2 = Depreciated Bal | | | | |
| 35 | | | | | |
| 36 | Misc. Data | | | | |
| 37 | | | | | |
| 38 | INFLATION RATE | 2.57% | 2.57% | 2.57% | 2.57% |
| 39 | PROP TAX ESC RATE | 2.57% | 2.57% | 2.57% | 2.57% |
| 40 | RETURN BASIS | 2 | 2 | 2 | 2 |
| 41 | 1 = Begin of Year | | | | |
| 42 | 2 = Avg Begin & End | | | | |
| 43 | 3 = End of Year | | | | |

Table - 8
National Grid - New Hampshire
Marginal Cost Study
**LEVELIZED FIXED CHARGE ANALYSIS Rev. 4.0.0**
**Peaker Plant**

| LINE NO. | ITEM | -- Current Dollars -- (Engineer's FCR) CURRENT LEVELIZED DOLLARS | PERCENT OF CAPITAL INVESTMENT | -- Constant Dollars -- (Economist's FCR) CONSTANT LEVELIZED DOLLARS | PERCENT OF CAPITAL INVESTMENT |
|---|---|---|---|---|---|
| 1 | INTEREST ON DEBT | $28.76 | 2.88% | $22.49 | 2.25% |
| 2 | RETURN ON PREF | $0.00 | 0.00% | $0.00 | 0.00% |
| 3 | RETURN ON COMMON | $35.95 | 3.59% | $28.11 | 2.81% |
| 4 | | | | | |
| 5 | RETURN | $64.71 | 6.47% | $50.60 | 5.06% |
| 6 | | | | | |
| 7 | DEPRECIATION | $33.33 | 3.33% | $26.07 | 2.61% |
| 8 | | | | | |
| 9 | INCOME TAX | $19.57 | 1.96% | $15.30 | 1.53% |
| 10 | DEFERRED TAXES | $4.92 | 0.49% | $3.85 | 0.38% |
| 11 | | | | | |
| 12 | INCOME TAX | $24.49 | 2.45% | $19.15 | 1.92% |
| 13 | | | | | |
| 14 | REVENUE TAX | $0.00 | 0.00% | $0.00 | 0.00% |
| 15 | PROPERTY TAX | $17.55 | 1.76% | $13.73 | 1.37% |
| 16 | PROPERTY INSURANCE | $0.00 | 0.00% | $0.00 | 0.00% |
| 17 | | | | | |
| 18 | OTHER | $17.55 | 1.76% | $13.73 | 1.37% |
| 19 | | | | | |
| 20 | | | | | |
| 21 | TOTAL REVENUE REQ'D | **$140.08** | **14.01%** | **$109.55** | **10.95%** |

Table - 8
National Grid - New Hampshire
Marginal Cost Study
LEVELIZED FIXED CHARGE ANALYSIS Rev. 4.0.0
Capacity Related Distribution

| | | -- Current Dollars -- (Engineer's FCR) | | -- Constant Dollars -- (Economist's FCR) | |
|---|---|---|---|---|---|
| LINE NO. | ITEM | CURRENT LEVELIZED DOLLARS | PERCENT OF CAPITAL INVESTMENT | CONSTANT LEVELIZED DOLLARS | PERCENT OF CAPITAL INVESTMENT |
| 1 | INTEREST ON DEBT | $30.29 | 3.03% | $21.74 | 2.17% |
| 2 | RETURN ON PREF | $0.00 | 0.00% | $0.00 | 0.00% |
| 3 | RETURN ON COMMON | $37.87 | 3.79% | $27.18 | 2.72% |
| 4 | | | | | |
| 5 | RETURN | $68.16 | 6.82% | $48.92 | 4.89% |
| 6 | | | | | |
| 7 | DEPRECIATION | $19.44 | 1.94% | $13.95 | 1.39% |
| 8 | | | | | |
| 9 | INCOME TAX | $16.67 | 1.67% | $11.96 | 1.20% |
| 10 | DEFERRED TAXES | $9.13 | 0.91% | $6.55 | 0.66% |
| 11 | | | | | |
| 12 | INCOME TAX | $25.80 | 2.58% | $18.51 | 1.85% |
| 13 | | | | | |
| 14 | REVENUE TAX | $0.00 | 0.00% | $0.00 | 0.00% |
| 15 | PROPERTY TAX | $20.81 | 2.08% | $14.93 | 1.49% |
| 16 | PROPERTY INSURANCE | $0.00 | 0.00% | $0.00 | 0.00% |
| 17 | | | | | |
| 18 | OTHER | $20.81 | 2.08% | $14.93 | 1.49% |
| 19 | | | | | |
| 20 | | | | | |
| 21 | TOTAL REVENUE REQ'D | **$134.20** | **13.42%** | **$96.32** | **9.63%** |

Table - 8
National Grid - New Hampshire
Marginal Cost Study
**LEVELIZED FIXED CHARGE ANALYSIS Rev. 4.0.0**
**Services Investment**

| | | -- Current Dollars -- (Engineer's FCR) | | -- Constant Dollars -- (Economist's FCR) | |
|---|---|---|---|---|---|
| LINE NO. | ITEM | CURRENT LEVELIZED DOLLARS | PERCENT OF CAPITAL INVESTMENT | CONSTANT LEVELIZED DOLLARS | PERCENT OF CAPITAL INVESTMENT |
| 1 | INTEREST ON DEBT | $24.45 | 2.45% | $18.34 | 1.83% |
| 2 | RETURN ON PREF | $0.00 | 0.00% | $0.00 | 0.00% |
| 3 | RETURN ON COMMON | $30.57 | 3.06% | $22.92 | 2.29% |
| 4 | | | | | |
| 5 | RETURN | $55.02 | 5.50% | $41.26 | 4.13% |
| 6 | | | | | |
| 7 | DEPRECIATION | $42.50 | 4.25% | $31.87 | 3.19% |
| 8 | | | | | |
| 9 | INCOME TAX | $19.66 | 1.97% | $14.74 | 1.47% |
| 10 | DEFERRED TAXES | $1.17 | 0.12% | $0.88 | 0.09% |
| 11 | | | | | |
| 12 | INCOME TAX | $20.82 | 2.08% | $15.62 | 1.56% |
| 13 | | | | | |
| 14 | REVENUE TAX | $0.00 | 0.00% | $0.00 | 0.00% |
| 15 | PROPERTY TAX | $14.48 | 1.45% | $10.86 | 1.09% |
| 16 | PROPERTY INSURANCE | $0.00 | 0.00% | $0.00 | 0.00% |
| 17 | | | | | |
| 18 | OTHER | $14.48 | 1.45% | $10.86 | 1.09% |
| 19 | | | | | |
| 20 | | | | | |
| 21 | TOTAL REVENUE REQ'D | **$132.83** | **13.28%** | **$99.61** | **9.96%** |
| 22 | | | | | |
| 23 | | | | | |

Table - 8
National Grid - New Hampshire
Marginal Cost Study
**LEVELIZED FIXED CHARGE ANALYSIS Rev. 4.0.0**
**Metering Equipment**

| | | -- Current Dollars -- (Engineer's FCR) | | -- Constant Dollars -- (Economist's FCR) | |
|---|---|---|---|---|---|
| LINE NO. | ITEM | CURRENT LEVELIZED DOLLARS | PERCENT OF CAPITAL INVESTMENT | CONSTANT LEVELIZED DOLLARS | PERCENT OF CAPITAL INVESTMENT |
| 1 | INTEREST ON DEBT | $29.13 | 2.91% | $22.26 | 2.23% |
| 2 | RETURN ON PREF | $0.00 | 0.00% | $0.00 | 0.00% |
| 3 | RETURN ON COMMON | $36.41 | 3.64% | $27.82 | 2.78% |
| 4 | | | | | |
| 5 | RETURN | $65.54 | 6.55% | $50.08 | 5.01% |
| 6 | | | | | |
| 7 | DEPRECIATION | $28.57 | 2.86% | $21.83 | 2.18% |
| 8 | | | | | |
| 9 | INCOME TAX | $18.52 | 1.85% | $14.15 | 1.42% |
| 10 | DEFERRED TAXES | $6.28 | 0.63% | $4.80 | 0.48% |
| 11 | | | | | |
| 12 | INCOME TAX | $24.80 | 2.48% | $18.95 | 1.90% |
| 13 | | | | | |
| 14 | REVENUE TAX | $0.00 | 0.00% | $0.00 | 0.00% |
| 15 | PROPERTY TAX | $18.45 | 1.84% | $14.10 | 1.41% |
| 16 | PROPERTY INSURANCE | $0.00 | 0.00% | $0.00 | 0.00% |
| 17 | | | | | |
| 18 | OTHER | $18.45 | 1.84% | $14.10 | 1.41% |
| 19 | | | | | |
| 20 | | | | | |
| 21 | TOTAL REVENUE REQ'D | **$137.36** | **13.74%** | **$104.97** | **10.50%** |

Table - B
National Grid - New Hampshire
Development of Revenue Requirements Stream

Peaker Plant

| Year No. | Rate Base | Interest On Debt | Return On Preferred | Return On Common | Tax Deprec'N | Book Deprec'N | Deferred Tax | Taxable Income | Inc Tax Payable | Revenue Tax | Property Tax | Property Insurance | ANNUAL Revenue Req'mTs | % of Original Investm't | Present Worth Of Rev ReqMt |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) |
| | 1,000.00 | | | | | | | | | | | | | | |
| 1 | 982.49 | 45.19 | 0.00 | 56.49 | 37.50 | 33.33 | 1.69 | 90.81 | 35.80 | 0.00 | 21.10 | 0.00 | 194.61 | 19.46% | 179.38 |
| 2 | 940.44 | 43.26 | 0.00 | 54.08 | 72.19 | 33.33 | 15.74 | 52.06 | 21.09 | 0.00 | 20.92 | 0.00 | 188.43 | 18.84% | 160.10 |
| 3 | 892.46 | 41.05 | 0.00 | 51.32 | 68.77 | 33.33 | 13.55 | 52.63 | 21.41 | 0.00 | 20.72 | 0.00 | 181.38 | 18.14% | 142.08 |
| 4 | 846.59 | 38.94 | 0.00 | 48.68 | 61.77 | 33.33 | 11.52 | 53.41 | 21.64 | 0.00 | 20.48 | 0.00 | 174.61 | 17.46% | 126.08 |
| 5 | 802.68 | 36.92 | 0.00 | 46.15 | 57.13 | 33.33 | 9.64 | 53.80 | 21.80 | 0.00 | 20.24 | 0.00 | 168.09 | 16.81% | 111.86 |
| 6 | 760.57 | 34.99 | 0.00 | 43.73 | 52.85 | 33.33 | 7.91 | 54.01 | 21.88 | 0.00 | 19.96 | 0.00 | 161.81 | 16.18% | 99.25 |
| 7 | 720.13 | 33.13 | 0.00 | 41.41 | 48.89 | 33.33 | 6.30 | 54.06 | 21.91 | 0.00 | 19.66 | 0.00 | 155.73 | 15.57% | 88.06 |
| 8 | 681.24 | 31.34 | 0.00 | 39.17 | 45.22 | 33.33 | 4.82 | 53.97 | 21.87 | 0.00 | 19.32 | 0.00 | 149.85 | 14.98% | 78.10 |
| 9 | 643.21 | 29.59 | 0.00 | 36.98 | 44.62 | 33.33 | 4.57 | 50.90 | 20.62 | 0.00 | 18.90 | 0.00 | 144.06 | 14.41% | 69.21 |
| 10 | 605.31 | 27.84 | 0.00 | 34.81 | 44.62 | 33.33 | 4.57 | 47.23 | 19.14 | 0.00 | 18.56 | 0.00 | 138.25 | 13.83% | 61.23 |
| 11 | 567.40 | 26.10 | 0.00 | 32.63 | 44.62 | 33.33 | 4.57 | 43.57 | 17.65 | 0.00 | 18.13 | 0.00 | 132.41 | 13.24% | 54.05 |
| 12 | 529.50 | 24.36 | 0.00 | 30.45 | 44.62 | 33.33 | 4.57 | 39.91 | 16.17 | 0.00 | 17.67 | 0.00 | 126.54 | 12.65% | 47.62 |
| 13 | 491.59 | 22.61 | 0.00 | 28.27 | 44.62 | 33.33 | 4.57 | 36.24 | 14.68 | 0.00 | 17.17 | 0.00 | 120.64 | 12.06% | 41.84 |
| 14 | 453.69 | 20.87 | 0.00 | 26.09 | 44.62 | 33.33 | 4.57 | 32.58 | 13.20 | 0.00 | 16.63 | 0.00 | 114.69 | 11.47% | 36.67 |
| 15 | 415.78 | 19.13 | 0.00 | 23.91 | 44.62 | 33.33 | 4.57 | 28.91 | 11.72 | 0.00 | 16.05 | 0.00 | 108.71 | 10.87% | 32.04 |
| 16 | 377.88 | 17.38 | 0.00 | 21.73 | 44.62 | 33.33 | 4.57 | 25.25 | 10.23 | 0.00 | 15.44 | 0.00 | 102.68 | 10.27% | 27.89 |
| 17 | 339.97 | 15.64 | 0.00 | 19.55 | 44.62 | 33.33 | 4.57 | 21.58 | 8.75 | 0.00 | 14.78 | 0.00 | 96.62 | 9.66% | 24.19 |
| 18 | 302.07 | 13.90 | 0.00 | 17.37 | 44.62 | 33.33 | 4.57 | 17.92 | 7.26 | 0.00 | 14.08 | 0.00 | 90.50 | 9.05% | 20.89 |
| 19 | 264.16 | 12.15 | 0.00 | 15.19 | 44.62 | 33.33 | 4.57 | 14.26 | 5.78 | 0.00 | 13.33 | 0.00 | 84.35 | 8.43% | 17.95 |
| 20 | 226.26 | 10.41 | 0.00 | 13.01 | 44.62 | 33.33 | 4.57 | 10.59 | 4.29 | 0.00 | 12.53 | 0.00 | 78.14 | 7.81% | 15.33 |
| 21 | 192.87 | 8.87 | 0.00 | 11.09 | 22.31 | 33.33 | (4.47) | 29.67 | 12.02 | 0.00 | 11.69 | 0.00 | 72.53 | 7.25% | 13.11 |
| 22 | 168.53 | 7.75 | 0.00 | 9.69 | 0.00 | 33.33 | (13.51) | 49.63 | 20.11 | 0.00 | 10.79 | 0.00 | 68.16 | 6.82% | 11.36 |
| 23 | 148.70 | 6.84 | 0.00 | 8.55 | 0.00 | 33.33 | (13.51) | 47.71 | 19.33 | 0.00 | 9.83 | 0.00 | 64.38 | 6.44% | 9.89 |
| 24 | 128.87 | 5.93 | 0.00 | 7.41 | 0.00 | 33.33 | (13.51) | 45.79 | 18.55 | 0.00 | 8.83 | 0.00 | 60.55 | 6.05% | 8.57 |
| 25 | 109.05 | 5.02 | 0.00 | 6.27 | 0.00 | 33.33 | (13.51) | 43.88 | 17.78 | 0.00 | 7.76 | 0.00 | 56.65 | 5.67% | 7.39 |
| 26 | 89.22 | 4.10 | 0.00 | 5.13 | 0.00 | 33.33 | (13.51) | 41.96 | 17.00 | 0.00 | 6.63 | 0.00 | 52.69 | 5.27% | 6.34 |
| 27 | 69.39 | 3.19 | 0.00 | 3.99 | 0.00 | 33.33 | (13.51) | 40.04 | 16.22 | 0.00 | 5.44 | 0.00 | 48.68 | 4.87% | 5.40 |
| 28 | 49.57 | 2.28 | 0.00 | 2.85 | 0.00 | 33.33 | (13.51) | 38.13 | 15.45 | 0.00 | 4.19 | 0.00 | 44.59 | 4.46% | 4.56 |
| 29 | 29.74 | 1.37 | 0.00 | 1.71 | 0.00 | 33.33 | (13.51) | 36.21 | 14.67 | 0.00 | 2.88 | 0.00 | 40.44 | 4.04% | 3.81 |
| 30 | 9.91 | 0.46 | 0.00 | 0.57 | 0.00 | 33.33 | (13.51) | 34.29 | 13.89 | 0.00 | 1.47 | 0.00 | 36.22 | 3.62% | 3.15 |
| 31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 38 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 39 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 41 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 43 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 45 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 46 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 50 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 51 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 53 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 56 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 57 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 59 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 60 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 64 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 65 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| TOTAL | | $590.01 | $0.00 | $738.26 | $1,000.00 | $1,000.00 | ($0.00) | $1,241.19 | $502.93 | $0.00 | $425.19 | $0.00 | $3,256.98 | | 1.507 |
| PRESENT WORTH | | $309.46 | $0.00 | $386.82 | $489.36 | $358.66 | $52.96 | $519.54 | $210.56 | $0.00 | $188.67 | $0.00 | $1,507.35 | 150.74% | |
| LEVELIZED PAYMENT | | $28.76 | $0.00 | $35.95 | $45.46 | $33.33 | $4.92 | $48.29 | $19.57 | $0.00 | $17.55 | $0.00 | $140.08 | 14.01% | |

Table - 8
National Grid - New Hampshire
Development of Revenue Requirements Stream

Capacity Related Distribution

| Year No. | Rate Base | Interest On Debt | Return On Preferred | Return On Common | Tax Deprec'N | Book Deprec'N | Deferred Tax | Taxable Income | Inc Tax Payable | Revenue Tax | Property Tax | Property Insurance | ANNUAL Revenue Reqm'Ts | % of Original Investm'T | Present Worth Of Rev Req'Mt |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) |
| | 1,000.00 | | | | | | | | | | | | | | |
| 1 | 988.62 | 45.38 | 0.00 | 66.73 | 37.50 | 19.44 | 7.32 | 77.31 | 31.33 | 0.00 | 21.10 | 0.00 | 181.30 | 18.13% | 187.12 |
| 2 | 952.84 | 43.83 | 0.00 | 64.79 | 72.19 | 19.44 | 21.37 | 39.36 | 15.95 | 0.00 | 21.22 | 0.00 | 176.60 | 17.66% | 150.05 |
| 3 | 913.12 | 42.00 | 0.00 | 52.50 | 66.77 | 19.44 | 19.18 | 40.94 | 16.59 | 0.00 | 21.34 | 0.00 | 171.05 | 17.10% | 133.97 |
| 4 | 875.52 | 40.27 | 0.00 | 50.34 | 61.77 | 19.44 | 17.15 | 42.31 | 17.14 | 0.00 | 21.44 | 0.00 | 165.79 | 16.58% | 119.69 |
| 5 | 839.87 | 38.63 | 0.00 | 48.29 | 57.13 | 19.44 | 15.27 | 43.49 | 17.62 | 0.00 | 21.54 | 0.00 | 160.80 | 16.08% | 107.01 |
| 6 | 806.03 | 37.08 | 0.00 | 46.35 | 52.85 | 19.44 | 13.54 | 44.51 | 18.03 | 0.00 | 21.63 | 0.00 | 156.06 | 15.61% | 95.73 |
| 7 | 773.86 | 35.60 | 0.00 | 44.50 | 48.88 | 19.44 | 11.93 | 45.38 | 18.38 | 0.00 | 21.70 | 0.00 | 151.55 | 15.15% | 85.69 |
| 8 | 743.23 | 34.18 | 0.00 | 42.74 | 45.22 | 19.44 | 10.45 | 46.07 | 18.67 | 0.00 | 21.77 | 0.00 | 147.25 | 14.72% | 76.75 |
| 9 | 713.47 | 32.82 | 0.00 | 41.02 | 44.62 | 19.44 | 10.20 | 43.79 | 17.76 | 0.00 | 21.83 | 0.00 | 143.06 | 14.31% | 68.73 |
| 10 | 683.83 | 31.46 | 0.00 | 39.32 | 44.62 | 19.44 | 10.20 | 40.93 | 16.58 | 0.00 | 21.88 | 0.00 | 138.87 | 13.89% | 61.50 |
| 11 | 654.19 | 30.09 | 0.00 | 37.62 | 44.62 | 19.44 | 10.20 | 38.06 | 15.42 | 0.00 | 21.91 | 0.00 | 134.68 | 13.47% | 54.98 |
| 12 | 624.55 | 28.73 | 0.00 | 35.91 | 44.62 | 19.44 | 10.20 | 35.20 | 14.26 | 0.00 | 21.93 | 0.00 | 130.47 | 13.05% | 49.09 |
| 13 | 594.91 | 27.37 | 0.00 | 34.21 | 44.62 | 19.44 | 10.20 | 32.33 | 13.10 | 0.00 | 21.94 | 0.00 | 126.25 | 12.63% | 43.79 |
| 14 | 565.28 | 26.00 | 0.00 | 32.50 | 44.62 | 19.44 | 10.20 | 29.47 | 11.94 | 0.00 | 21.93 | 0.00 | 122.02 | 12.20% | 39.01 |
| 15 | 535.64 | 24.64 | 0.00 | 30.80 | 44.62 | 19.44 | 10.20 | 26.60 | 10.78 | 0.00 | 21.91 | 0.00 | 117.77 | 11.78% | 34.71 |
| 16 | 506.00 | 23.28 | 0.00 | 29.09 | 44.62 | 19.44 | 10.20 | 23.74 | 9.62 | 0.00 | 21.87 | 0.00 | 113.50 | 11.35% | 30.83 |
| 17 | 476.38 | 21.91 | 0.00 | 27.39 | 44.62 | 19.44 | 10.20 | 20.87 | 8.46 | 0.00 | 21.82 | 0.00 | 109.22 | 10.92% | 27.35 |
| 18 | 446.72 | 20.55 | 0.00 | 25.69 | 44.62 | 19.44 | 10.20 | 18.01 | 7.30 | 0.00 | 21.75 | 0.00 | 104.92 | 10.49% | 24.22 |
| 19 | 417.08 | 19.19 | 0.00 | 23.98 | 44.62 | 19.44 | 10.20 | 15.14 | 6.14 | 0.00 | 21.66 | 0.00 | 100.60 | 10.06% | 21.40 |
| 20 | 387.44 | 17.82 | 0.00 | 22.28 | 44.62 | 19.44 | 10.20 | 12.28 | 4.97 | 0.00 | 21.55 | 0.00 | 96.27 | 9.63% | 18.88 |
| 21 | 362.32 | 16.67 | 0.00 | 20.83 | 22.31 | 19.44 | 1.76 | 32.16 | 13.03 | 0.00 | 21.43 | 0.00 | 92.55 | 9.26% | 16.73 |
| 22 | 346.24 | 15.93 | 0.00 | 19.91 | 0.00 | 19.44 | (7.88) | 52.91 | 21.44 | 0.00 | 21.28 | 0.00 | 90.11 | 9.01% | 15.02 |
| 23 | 334.68 | 15.40 | 0.00 | 19.24 | 0.00 | 19.44 | (7.88) | 51.79 | 20.99 | 0.00 | 21.11 | 0.00 | 88.29 | 8.83% | 13.56 |
| 24 | 323.12 | 14.86 | 0.00 | 18.58 | 0.00 | 19.44 | (7.88) | 50.67 | 20.53 | 0.00 | 20.91 | 0.00 | 86.45 | 8.65% | 12.24 |
| 25 | 311.56 | 14.33 | 0.00 | 17.91 | 0.00 | 19.44 | (7.88) | 49.56 | 20.08 | 0.00 | 20.70 | 0.00 | 84.59 | 8.46% | 11.04 |
| 26 | 300.00 | 13.80 | 0.00 | 17.25 | 0.00 | 19.44 | (7.88) | 48.44 | 19.63 | 0.00 | 20.48 | 0.00 | 82.69 | 8.27% | 9.95 |
| 27 | 288.44 | 13.27 | 0.00 | 16.59 | 0.00 | 19.44 | (7.88) | 47.32 | 19.17 | 0.00 | 20.19 | 0.00 | 80.76 | 8.08% | 8.96 |
| 28 | 276.88 | 12.74 | 0.00 | 15.92 | 0.00 | 19.44 | (7.88) | 46.20 | 18.72 | 0.00 | 19.89 | 0.00 | 78.83 | 7.88% | 8.06 |
| 29 | 265.32 | 12.20 | 0.00 | 15.26 | 0.00 | 19.44 | (7.88) | 45.09 | 18.27 | 0.00 | 19.57 | 0.00 | 76.86 | 7.69% | 7.24 |
| 30 | 253.76 | 11.67 | 0.00 | 14.59 | 0.00 | 19.44 | (7.88) | 43.97 | 17.82 | 0.00 | 19.22 | 0.00 | 74.86 | 7.49% | 6.50 |
| 31 | 242.20 | 11.14 | 0.00 | 13.93 | 0.00 | 19.44 | (7.88) | 42.85 | 17.36 | 0.00 | 18.83 | 0.00 | 72.82 | 7.28% | 5.83 |
| 32 | 230.64 | 10.61 | 0.00 | 13.26 | 0.00 | 19.44 | (7.88) | 41.73 | 16.91 | 0.00 | 18.42 | 0.00 | 70.76 | 7.08% | 5.22 |
| 33 | 219.07 | 10.08 | 0.00 | 12.60 | 0.00 | 19.44 | (7.88) | 40.61 | 16.46 | 0.00 | 17.97 | 0.00 | 68.66 | 6.87% | 4.67 |
| 34 | 207.51 | 9.55 | 0.00 | 11.93 | 0.00 | 19.44 | (7.88) | 39.50 | 16.00 | 0.00 | 17.48 | 0.00 | 66.52 | 6.65% | 4.17 |
| 35 | 195.95 | 9.01 | 0.00 | 11.27 | 0.00 | 19.44 | (7.88) | 38.38 | 15.55 | 0.00 | 16.96 | 0.00 | 64.35 | 6.44% | 3.72 |
| 36 | 184.39 | 8.48 | 0.00 | 10.60 | 0.00 | 19.44 | (7.88) | 37.26 | 15.10 | 0.00 | 16.40 | 0.00 | 62.14 | 6.21% | 3.31 |
| 37 | 172.83 | 7.95 | 0.00 | 9.94 | 0.00 | 19.44 | (7.88) | 36.14 | 14.65 | 0.00 | 15.80 | 0.00 | 59.89 | 5.99% | 2.94 |
| 38 | 161.27 | 7.42 | 0.00 | 9.27 | 0.00 | 19.44 | (7.88) | 35.03 | 14.19 | 0.00 | 15.15 | 0.00 | 57.60 | 5.76% | 2.61 |
| 39 | 149.71 | 6.89 | 0.00 | 8.61 | 0.00 | 19.44 | (7.88) | 33.91 | 13.74 | 0.00 | 14.47 | 0.00 | 55.28 | 5.53% | 2.31 |
| 40 | 138.15 | 6.35 | 0.00 | 7.94 | 0.00 | 19.44 | (7.88) | 32.79 | 13.29 | 0.00 | 13.74 | 0.00 | 52.88 | 5.29% | 2.03 |
| 41 | 126.59 | 5.82 | 0.00 | 7.28 | 0.00 | 19.44 | (7.88) | 31.67 | 12.83 | 0.00 | 12.96 | 0.00 | 50.45 | 5.05% | 1.79 |
| 42 | 115.03 | 5.29 | 0.00 | 6.61 | 0.00 | 19.44 | (7.88) | 30.56 | 12.38 | 0.00 | 12.13 | 0.00 | 47.98 | 4.80% | 1.57 |
| 43 | 103.47 | 4.76 | 0.00 | 5.95 | 0.00 | 19.44 | (7.88) | 29.44 | 11.93 | 0.00 | 11.25 | 0.00 | 45.45 | 4.54% | 1.37 |
| 44 | 91.91 | 4.23 | 0.00 | 5.28 | 0.00 | 19.44 | (7.88) | 28.32 | 11.48 | 0.00 | 10.32 | 0.00 | 42.87 | 4.29% | 1.19 |
| 45 | 80.34 | 3.70 | 0.00 | 4.62 | 0.00 | 19.44 | (7.88) | 27.20 | 11.02 | 0.00 | 9.33 | 0.00 | 40.23 | 4.02% | 1.03 |
| 46 | 68.78 | 3.16 | 0.00 | 3.96 | 0.00 | 19.44 | (7.88) | 26.09 | 10.57 | 0.00 | 8.29 | 0.00 | 37.54 | 3.75% | 0.89 |
| 47 | 57.22 | 2.63 | 0.00 | 3.29 | 0.00 | 19.44 | (7.88) | 24.97 | 10.12 | 0.00 | 7.16 | 0.00 | 34.78 | 3.48% | 0.76 |
| 48 | 45.66 | 2.10 | 0.00 | 2.63 | 0.00 | 19.44 | (7.88) | 23.85 | 9.66 | 0.00 | 6.01 | 0.00 | 31.97 | 3.20% | 0.64 |
| 49 | 34.10 | 1.57 | 0.00 | 1.96 | 0.00 | 19.44 | (7.88) | 22.73 | 9.21 | 0.00 | 4.78 | 0.00 | 29.08 | 2.91% | 0.54 |
| 50 | 22.54 | 1.04 | 0.00 | 1.30 | 0.00 | 19.44 | (7.88) | 21.62 | 8.76 | 0.00 | 3.48 | 0.00 | 26.14 | 2.61% | 0.45 |
| 51 | 10.98 | 0.51 | 0.00 | 0.63 | 0.00 | 19.44 | (7.88) | 20.50 | 8.31 | 0.00 | 2.11 | 0.00 | 23.12 | 2.31% | 0.36 |
| 52 | (0.58) | (0.03) | 0.00 | (0.03) | 0.00 | 19.44 | (7.88) | 19.38 | 7.85 | 0.00 | 0.67 | 0.00 | 20.03 | 2.00% | 0.29 |
| 53 | (12.14) | (0.56) | 0.00 | (0.70) | 0.00 | 19.44 | (7.88) | 18.26 | 7.40 | 0.00 | 0.00 | 0.00 | 17.70 | 1.77% | 0.24 |
| 54 | (23.70) | (1.09) | 0.00 | (1.36) | 0.00 | 19.44 | (7.88) | 17.15 | 6.95 | 0.00 | 0.00 | 0.00 | 16.05 | 1.61% | 0.20 |
| 55 | (35.26) | (1.62) | 0.00 | (2.03) | 0.00 | 19.44 | (7.88) | 16.03 | 6.49 | 0.00 | 0.00 | 0.00 | 14.41 | 1.44% | 0.16 |
| 56 | (46.82) | (2.15) | 0.00 | (2.69) | 0.00 | 19.44 | (7.88) | 14.91 | 6.04 | 0.00 | 0.00 | 0.00 | 12.78 | 1.28% | 0.13 |
| 57 | (58.38) | (2.69) | 0.00 | (3.36) | 0.00 | 19.44 | (7.88) | 13.79 | 5.59 | 0.00 | 0.00 | 0.00 | 11.11 | 1.11% | 0.11 |
| 58 | (69.95) | (3.22) | 0.00 | (4.02) | 0.00 | 19.44 | (7.88) | 12.67 | 5.14 | 0.00 | 0.00 | 0.00 | 9.46 | 0.95% | 0.08 |
| 59 | (81.51) | (3.75) | 0.00 | (4.69) | 0.00 | 19.44 | (7.88) | 11.56 | 4.68 | 0.00 | 0.00 | 0.00 | 7.81 | 0.78% | 0.06 |
| 60 | 29.73 | 1.37 | 0.00 | 1.71 | 146.75 | 0.00 | 59.48 | (143.68) | (58.30) | 0.00 | 0.00 | 0.00 | 4.24 | 0.42% | 0.03 |
| 61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 64 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 65 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| TOTAL | | $870.29 | $0.00 | $1,087.82 | $1,146.75 | $1,146.75 | $0.00 | $1,826.89 | $741.08 | $0.00 | $892.19 | $0.00 | $4,736.09 | | 1,588 |
| PRESENT WORTH | | $354.06 | $0.00 | $442.58 | $450.49 | $227.16 | $106.70 | $480.75 | $194.80 | $0.00 | $243.18 | $0.00 | $1,508.48 | 150.85% | |
| LEVELIZED PAYMENT | | $30.29 | $0.00 | $37.87 | $41.97 | $19.44 | $9.13 | $41.13 | $16.67 | $0.00 | $20.81 | $0.00 | $134.20 | 13.42% | |

Table - 8
National Grid - New Hampshire
Development of Revenue Requirements Stream

Services Investment

| Year No. | Rate Base | Interest On Debt | Return On Preferred | Return On Common | Tax Deprec'N | Book Deprec'N | Deferred Tax | Taxable Income | Inc Tax Payable | Revenue Tax | Property Tax | Property Insurance | ANNUAL Revenue Req'm'Ts | % of Original Investm't | Present Worth Of Rev Req'Mt |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) |
| | 1,000.00 | | | | | | | | | | | | | | |
| 1 | 979.78 | 46.07 | 0.00 | 56.34 | 37.50 | 42.50 | (2.03) | 98.71 | 40.40 | 0.00 | 21.10 | 0.00 | 203.38 | 20.34% | 187.47 |
| 2 | 932.26 | 42.88 | 0.00 | 53.61 | 72.19 | 42.50 | 12.03 | 60.44 | 24.49 | 0.00 | 20.72 | 0.00 | 196.23 | 19.62% | 168.73 |
| 3 | 878.83 | 40.43 | 0.00 | 50.53 | 66.77 | 42.50 | 8.84 | 60.66 | 24.59 | 0.00 | 20.31 | 0.00 | 188.20 | 18.82% | 147.40 |
| 4 | 827.51 | 38.07 | 0.00 | 47.58 | 61.77 | 42.50 | 7.81 | 60.73 | 24.61 | 0.00 | 19.87 | 0.00 | 180.43 | 18.04% | 130.20 |
| 5 | 778.14 | 35.79 | 0.00 | 44.74 | 57.13 | 42.50 | 5.93 | 60.59 | 24.55 | 0.00 | 19.38 | 0.00 | 172.90 | 17.29% | 115.06 |
| 6 | 730.58 | 33.61 | 0.00 | 42.01 | 52.85 | 42.50 | 4.19 | 60.26 | 24.42 | 0.00 | 18.86 | 0.00 | 165.60 | 16.56% | 101.58 |
| 7 | 684.69 | 31.50 | 0.00 | 39.37 | 48.88 | 42.50 | 2.59 | 59.81 | 24.23 | 0.00 | 18.30 | 0.00 | 158.49 | 15.85% | 89.62 |
| 8 | 640.34 | 29.46 | 0.00 | 36.82 | 45.22 | 42.50 | 1.10 | 59.16 | 23.98 | 0.00 | 17.70 | 0.00 | 151.56 | 15.16% | 79.00 |
| 9 | 596.87 | 27.46 | 0.00 | 34.32 | 44.62 | 42.50 | 0.86 | 55.56 | 22.52 | 0.00 | 17.08 | 0.00 | 144.72 | 14.47% | 68.53 |
| 10 | 553.51 | 25.46 | 0.00 | 31.83 | 44.62 | 42.50 | 0.86 | 51.39 | 20.82 | 0.00 | 16.37 | 0.00 | 137.84 | 13.78% | 61.04 |
| 11 | 510.15 | 23.47 | 0.00 | 29.33 | 44.62 | 42.50 | 0.86 | 47.20 | 19.13 | 0.00 | 15.84 | 0.00 | 130.92 | 13.09% | 53.44 |
| 12 | 466.79 | 21.47 | 0.00 | 26.84 | 44.62 | 42.50 | 0.86 | 43.01 | 17.43 | 0.00 | 14.85 | 0.00 | 123.95 | 12.40% | 46.64 |
| 13 | 423.44 | 19.48 | 0.00 | 24.35 | 44.62 | 42.50 | 0.86 | 38.82 | 15.73 | 0.00 | 14.02 | 0.00 | 116.93 | 11.69% | 40.56 |
| 14 | 380.08 | 17.48 | 0.00 | 21.85 | 44.62 | 42.50 | 0.86 | 34.63 | 14.03 | 0.00 | 13.13 | 0.00 | 109.86 | 10.99% | 35.12 |
| 15 | 336.72 | 15.49 | 0.00 | 19.36 | 44.62 | 42.50 | 0.86 | 30.44 | 12.33 | 0.00 | 12.19 | 0.00 | 102.73 | 10.27% | 30.28 |
| 16 | 293.37 | 13.49 | 0.00 | 16.87 | 44.62 | 42.50 | 0.86 | 26.24 | 10.63 | 0.00 | 11.19 | 0.00 | 95.55 | 9.55% | 25.98 |
| 17 | 250.01 | 11.50 | 0.00 | 14.38 | 44.62 | 42.50 | 0.86 | 22.05 | 8.94 | 0.00 | 10.13 | 0.00 | 88.30 | 8.83% | 22.11 |
| 18 | 206.65 | 9.51 | 0.00 | 11.88 | 44.62 | 42.50 | 0.86 | 17.86 | 7.24 | 0.00 | 9.01 | 0.00 | 81.00 | 8.10% | 18.70 |
| 19 | 163.29 | 7.51 | 0.00 | 9.39 | 44.62 | 42.50 | 0.86 | 13.67 | 5.54 | 0.00 | 7.83 | 0.00 | 73.63 | 7.36% | 15.66 |
| 20 | 119.94 | 5.52 | 0.00 | 6.90 | 44.62 | 42.50 | 0.86 | 9.48 | 3.84 | 0.00 | 6.58 | 0.00 | 66.19 | 6.62% | 12.98 |
| 21 | 81.10 | 3.73 | 0.00 | 4.66 | 22.31 | 42.50 | (8.10) | 28.03 | 11.36 | 0.00 | 5.28 | 0.00 | 58.33 | 5.93% | 10.73 |
| 22 | 51.30 | 2.36 | 0.00 | 2.95 | 0.00 | 42.50 | (17.22) | 47.46 | 19.23 | 0.00 | 3.88 | 0.00 | 53.68 | 5.37% | 8.95 |
| 23 | 26.02 | 1.20 | 0.00 | 1.50 | 0.00 | 42.50 | (17.22) | 45.02 | 18.24 | 0.00 | 2.40 | 0.00 | 48.61 | 4.86% | 7.47 |
| 24 | 0.74 | 0.03 | 0.00 | 0.04 | 0.00 | 42.50 | (17.22) | 42.57 | 17.25 | 0.00 | 0.85 | 0.00 | 43.46 | 4.35% | 6.15 |
| 25 | (24.54) | (1.13) | 0.00 | (1.41) | 0.00 | 42.50 | (17.22) | 40.13 | 16.26 | 0.00 | 0.00 | 0.00 | 39.00 | 3.90% | 5.09 |
| 26 | (49.81) | (2.29) | 0.00 | (2.86) | 0.00 | 42.50 | (17.22) | 37.68 | 15.27 | 0.00 | 0.00 | 0.00 | 35.39 | 3.54% | 4.28 |
| 27 | (75.09) | (3.45) | 0.00 | (4.32) | 0.00 | 42.50 | (17.22) | 35.24 | 14.28 | 0.00 | 0.00 | 0.00 | 31.79 | 3.18% | 3.52 |
| 28 | (100.37) | (4.62) | 0.00 | (5.77) | 0.00 | 42.50 | (17.22) | 32.80 | 13.29 | 0.00 | 0.00 | 0.00 | 28.18 | 2.82% | 2.88 |
| 29 | (125.65) | (5.78) | 0.00 | (7.22) | 0.00 | 42.50 | (17.22) | 30.35 | 12.30 | 0.00 | 0.00 | 0.00 | 24.57 | 2.46% | 2.32 |
| 30 | (150.93) | (6.94) | 0.00 | (8.68) | 0.00 | 42.50 | (17.22) | 27.91 | 11.31 | 0.00 | 0.00 | 0.00 | 20.97 | 2.10% | 1.82 |
| 31 | (176.21) | (8.11) | 0.00 | (10.13) | 0.00 | 42.50 | (17.22) | 25.47 | 10.32 | 0.00 | 0.00 | 0.00 | 17.36 | 1.74% | 1.39 |
| 32 | (201.49) | (9.27) | 0.00 | (11.59) | 0.00 | 42.50 | (17.22) | 23.02 | 9.33 | 0.00 | 0.00 | 0.00 | 13.75 | 1.38% | 1.01 |
| 33 | (226.77) | (10.43) | 0.00 | (13.04) | 0.00 | 42.50 | (17.22) | 20.58 | 8.34 | 0.00 | 0.00 | 0.00 | 10.15 | 1.01% | 0.69 |
| 34 | (252.05) | (11.59) | 0.00 | (14.49) | 0.00 | 42.50 | (17.22) | 18.13 | 7.35 | 0.00 | 0.00 | 0.00 | 6.54 | 0.65% | 0.41 |
| 35 | (277.33) | (12.70) | 0.00 | (15.95) | 0.00 | 42.50 | (17.22) | 15.69 | 6.36 | 0.00 | 0.00 | 0.00 | 2.93 | 0.29% | 0.17 |
| 36 | (302.60) | (13.92) | 0.00 | (17.40) | 0.00 | 42.50 | (17.22) | 13.25 | 5.37 | 0.00 | 0.00 | 0.00 | (0.67) | -0.07% | (0.04) |
| 37 | (327.88) | (15.08) | 0.00 | (18.85) | 0.00 | 42.50 | (17.22) | 10.80 | 4.38 | 0.00 | 0.00 | 0.00 | (4.28) | -0.43% | (0.21) |
| 38 | (353.16) | (16.25) | 0.00 | (20.31) | 0.00 | 42.50 | (17.22) | 8.36 | 3.39 | 0.00 | 0.00 | 0.00 | (7.89) | -0.79% | (0.36) |
| 39 | (378.44) | (17.41) | 0.00 | (21.76) | 0.00 | 42.50 | (17.22) | 5.92 | 2.40 | 0.00 | 0.00 | 0.00 | (11.49) | -1.15% | (0.48) |
| 40 | (403.72) | (18.57) | 0.00 | (23.21) | 0.00 | 42.50 | (17.22) | 3.47 | 1.41 | 0.00 | 0.00 | 0.00 | (15.10) | -1.51% | (0.58) |
| 41 | 141.82 | 6.52 | 0.00 | 8.15 | 700.00 | 0.00 | 283.64 | (686.29) | (278.08) | 0.00 | 0.00 | 0.00 | 20.23 | 2.02% | 0.72 |
| 42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 43 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 45 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 46 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 50 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 51 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 53 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 56 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 57 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 59 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 60 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 64 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| 65 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% | 0.00 |
| TOTAL | | $350.86 | $0.00 | $438.60 | $1,700.00 | $1,700.00 | ($0.00) | $737.40 | $298.79 | $0.00 | $316.84 | $0.00 | $3,104.01 | | 1,505 |
| PRESENT WORTH | | $277.07 | $0.00 | $346.34 | $514.20 | $481.66 | $13.23 | $549.64 | $222.71 | $0.00 | $164.13 | $0.00 | $1,505.04 | 150.50% | |
| LEVELIZED PAYMENT | | $24.45 | $0.00 | $30.57 | $45.36 | $42.50 | $1.17 | $48.51 | $19.66 | $0.00 | $14.46 | $0.00 | $132.83 | 13.28% | |

Table - 6
National Grid - New Hampshire
Development of Revenue Requirements Stream

Metering Equipment

| Year No. | Rate Base | Interest On Debt | Return On Preferred | Return On Common | Tax Deprec'N | Book Deprec'N | Deferred Tax | Taxable Income | Inc Tax Payable | Revenue Tax | Property Tax | Property Insurance | ANNUAL Reveue Req'mTs | % of Original Investm't | Present Worth Of Rev Req'Mt |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) |
| | 1,000.00 | | | | | | | | | | | | | | |
| 1 | 983.91 | 45.26 | 0.00 | 56.57 | 37.50 | 28.57 | 3.62 | 86.19 | 34.92 | 0.00 | 21.10 | 0.00 | 190.05 | 19.00% | 175.18 |
| 2 | 944.69 | 43.46 | 0.00 | 54.32 | 72.19 | 28.57 | 17.67 | 47.71 | 19.33 | 0.00 | 21.02 | 0.00 | 184.39 | 18.44% | 156.66 |
| 3 | 899.54 | 41.38 | 0.00 | 51.72 | 66.77 | 28.57 | 15.40 | 48.70 | 19.76 | 0.00 | 20.93 | 0.00 | 177.84 | 17.78% | 139.29 |
| 4 | 856.50 | 39.40 | 0.00 | 49.25 | 61.77 | 28.57 | 13.45 | 49.61 | 20.10 | 0.00 | 20.82 | 0.00 | 171.69 | 17.16% | 123.88 |
| 5 | 815.42 | 37.51 | 0.00 | 46.89 | 57.13 | 28.57 | 11.57 | 50.27 | 20.37 | 0.00 | 20.69 | 0.00 | 165.59 | 16.56% | 110.20 |
| 6 | 776.14 | 35.70 | 0.00 | 44.63 | 52.85 | 28.57 | 9.84 | 50.75 | 20.57 | 0.00 | 20.53 | 0.00 | 159.84 | 15.98% | 98.05 |
| 7 | 738.54 | 33.97 | 0.00 | 42.47 | 48.89 | 28.57 | 8.23 | 51.08 | 20.70 | 0.00 | 20.36 | 0.00 | 154.30 | 15.43% | 87.25 |
| 8 | 702.48 | 32.31 | 0.00 | 40.39 | 45.22 | 28.57 | 6.75 | 51.20 | 20.77 | 0.00 | 20.16 | 0.00 | 148.99 | 14.90% | 77.64 |
| 9 | 667.29 | 30.70 | 0.00 | 38.37 | 44.62 | 28.57 | 6.50 | 48.40 | 19.64 | 0.00 | 19.94 | 0.00 | 143.71 | 14.37% | 69.05 |
| 10 | 632.21 | 29.08 | 0.00 | 36.35 | 44.62 | 28.57 | 6.50 | 45.07 | 18.26 | 0.00 | 19.70 | 0.00 | 138.47 | 13.85% | 61.32 |
| 11 | 597.14 | 27.47 | 0.00 | 34.34 | 44.62 | 28.57 | 6.50 | 41.68 | 16.89 | 0.00 | 19.42 | 0.00 | 133.19 | 13.32% | 54.37 |
| 12 | 562.07 | 25.86 | 0.00 | 32.32 | 44.62 | 28.57 | 6.50 | 38.29 | 15.52 | 0.00 | 19.13 | 0.00 | 127.89 | 12.79% | 48.12 |
| 13 | 527.00 | 24.24 | 0.00 | 30.30 | 44.62 | 28.57 | 6.50 | 34.90 | 14.14 | 0.00 | 18.80 | 0.00 | 122.58 | 12.26% | 42.51 |
| 14 | 491.92 | 22.63 | 0.00 | 28.29 | 44.62 | 28.57 | 6.50 | 31.51 | 12.77 | 0.00 | 18.45 | 0.00 | 117.20 | 11.72% | 37.47 |
| 15 | 456.85 | 21.02 | 0.00 | 26.27 | 44.62 | 28.57 | 6.50 | 28.12 | 11.39 | 0.00 | 18.06 | 0.00 | 111.81 | 11.18% | 32.95 |
| 16 | 421.78 | 19.40 | 0.00 | 24.25 | 44.62 | 28.57 | 6.50 | 24.73 | 10.02 | 0.00 | 17.64 | 0.00 | 106.39 | 10.64% | 28.90 |
| 17 | 386.71 | 17.79 | 0.00 | 22.24 | 44.62 | 28.57 | 6.50 | 21.34 | 8.65 | 0.00 | 17.19 | 0.00 | 100.93 | 10.09% | 25.27 |
| 18 | 351.63 | 16.18 | 0.00 | 20.22 | 44.62 | 28.57 | 6.50 | 17.95 | 7.27 | 0.00 | 16.70 | 0.00 | 95.44 | 9.54% | 22.03 |
| 19 | 316.56 | 14.56 | 0.00 | 18.20 | 44.62 | 28.57 | 6.50 | 14.56 | 5.90 | 0.00 | 16.18 | 0.00 | 89.92 | 8.99% | 19.13 |
| 20 | 281.49 | 12.95 | 0.00 | 16.19 | 44.62 | 28.57 | 6.50 | 11.17 | 4.53 | 0.00 | 15.62 | 0.00 | 84.35 | 8.44% | 16.54 |
| 21 | 250.94 | 11.54 | 0.00 | 14.43 | 22.31 | 28.57 | (2.54) | 30.52 | 12.37 | 0.00 | 15.02 | 0.00 | 79.38 | 7.94% | 14.35 |
| 22 | 229.42 | 10.55 | 0.00 | 13.19 | 0.00 | 28.57 | (11.58) | 50.75 | 20.56 | 0.00 | 14.38 | 0.00 | 75.68 | 7.57% | 12.61 |
| 23 | 212.43 | 9.77 | 0.00 | 12.21 | 0.00 | 28.57 | (11.58) | 49.11 | 19.90 | 0.00 | 13.70 | 0.00 | 72.58 | 7.26% | 11.15 |
| 24 | 195.43 | 8.99 | 0.00 | 11.24 | 0.00 | 28.57 | (11.58) | 47.46 | 19.23 | 0.00 | 12.97 | 0.00 | 69.42 | 6.94% | 9.83 |
| 25 | 178.44 | 8.21 | 0.00 | 10.26 | 0.00 | 28.57 | (11.58) | 45.82 | 18.57 | 0.00 | 12.19 | 0.00 | 66.22 | 6.62% | 8.64 |
| 26 | 161.45 | 7.43 | 0.00 | 9.28 | 0.00 | 28.57 | (11.58) | 44.18 | 17.90 | 0.00 | 11.37 | 0.00 | 62.97 | 6.30% | 7.58 |
| 27 | 144.45 | 6.64 | 0.00 | 8.31 | 0.00 | 28.57 | (11.58) | 42.54 | 17.24 | 0.00 | 10.50 | 0.00 | 59.68 | 5.97% | 6.62 |
| 28 | 127.46 | 5.86 | 0.00 | 7.33 | 0.00 | 28.57 | (11.58) | 40.89 | 16.57 | 0.00 | 9.57 | 0.00 | 56.32 | 5.63% | 5.76 |
| 29 | 110.46 | 5.08 | 0.00 | 6.35 | 0.00 | 28.57 | (11.58) | 39.25 | 15.90 | 0.00 | 8.59 | 0.00 | 52.92 | 5.29% | 4.99 |
| 30 | 93.47 | 4.30 | 0.00 | 5.37 | 0.00 | 28.57 | (11.58) | 37.61 | 15.24 | 0.00 | 7.55 | 0.00 | 49.48 | 4.95% | 4.30 |
| 31 | 76.47 | 3.52 | 0.00 | 4.40 | 0.00 | 28.57 | (11.58) | 35.96 | 14.57 | 0.00 | 6.45 | 0.00 | 45.94 | 4.59% | 3.68 |
| 32 | 59.48 | 2.74 | 0.00 | 3.42 | 0.00 | 28.57 | (11.58) | 34.32 | 13.91 | 0.00 | 5.30 | 0.00 | 42.35 | 4.24% | 3.13 |
| 33 | 42.48 | 1.95 | 0.00 | 2.44 | 0.00 | 28.57 | (11.58) | 32.68 | 13.24 | 0.00 | 4.07 | 0.00 | 38.71 | 3.87% | 2.63 |
| 34 | 25.48 | 1.17 | 0.00 | 1.47 | 0.00 | 28.57 | (11.58) | 31.04 | 12.58 | 0.00 | 2.79 | 0.00 | 34.99 | 3.50% | 2.19 |
| 35 | 8.50 | 0.39 | 0.00 | 0.49 | 0.00 | 28.57 | (11.58) | 29.39 | 11.91 | 0.00 | 1.43 | 0.00 | 31.21 | 3.12% | 1.80 |
| 36 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 37 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 38 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 39 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 40 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 41 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 42 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 43 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 44 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 45 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 46 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 47 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 48 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 49 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 50 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 51 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 52 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 53 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 54 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 55 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 56 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 57 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 58 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 59 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 60 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 61 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 62 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 63 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 64 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| 65 | (0.00) | (0.00) | 0.00 | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | (0.00) | 0.00 | 0.00 | 0.00 | (0.00) | 0.00% | (0.00) |
| TOTAL | | $659.01 | $0.00 | $823.78 | $1,000.00 | $1,000.00 | ($0.00) | $1,384.94 | $561.18 | $0.00 | $518.31 | $0.00 | $3,562.25 | | 1,525 |
| PRESENT WORTH | | $323.39 | $0.00 | $404.24 | $489.38 | $317.23 | $89.76 | $507.47 | $205.63 | $0.00 | $204.60 | $0.00 | $1,525.05 | 152.50% | |
| LEVELIZED PAYMENT | | $29.13 | $0.00 | $36.41 | $44.09 | $28.57 | $0.28 | $45.71 | $18.52 | $0.00 | $18.45 | $0.00 | $137.36 | 13.74% | |

Table - 8
National Grid - New Hampshire
Marginal Cost Study

**Development of Weighted Plant Book Lives and Salvage**

| Line No. | Description | 2006 Plant Balance | Average Service Life | Net Salvage Value |
|---|---|---|---|---|
| | (1) | (2) {1} | (3) {2} | (4) {2} |
| | **HYPOTHETICAL PRODUCTION PLANT** | | | |
| 1 | Structures & Improvements | 43.3% | 30 | 0% |
| 2 | Other Power Equipment | 10.2% | 30 | 0% |
| 3 | L.P. Gas Equipment | 34.1% | 30 | 0% |
| 4 | Gas Mixing Equipment | 7.1% | 30 | 0% |
| 5 | Other Equipment | 5.2% | 30 | 0% |
| 6 | L.N.G. Equipment | 0.0% | 30 | 0% |
| 7 | | | | |
| 8 | Total Production Plant | 100.0% | 30 | 0% |
| 9 | | | | |
| 10 | | | | |
| 11 | **DISTRIBUTION INVESTMENT (excluding Customer Equip)** | | | |
| 12 | | | | |
| 13 | | | | |
| 14 | 1308.6 Distribution Plant Structures | 544,322 | 30 | 0% |
| 15 | 1356 Mains | 136,231,396 | 60 | -15% |
| 16 | 1358 Pumping & Regulating Equipment | 2,473,039 | 30 | 0% |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | Total Distribution Capacity-Related | $139,248,757 | 59 | -15% |
| 21 | | | | |
| 22 | | | | |
| 23 | | | | |
| 24 | | | | |
| 25 | | | | |
| 26 | 1359 Services | 80,850,399 | 40 | -70% |
| 27 | | | | |
| 28 | | | | |
| 29 | 1360 Customer Meters & Installations | 21,192,242 | 35 | 0% |

NOTES:
1 Plant balances taken from Annual Report of 12/31/2006. Production weighting taken from Table - 1, pages 2.
2 Service lives and salvage values based on current depreciation study.

Table - 9
National Grid - New Hampshire
Marginal Cost Study

**Summary of Marginal Capacity Costs**

| Line No. | Description | ---- PRODUCTION ---- Supply Related | Transp. Related | ----TRANS & DIST---- Mains Reinforce | Mains Extension | Total Dist | Total Prod & Dist |
|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| | **PLANT INVESTMENT** | | | | | | |
| 1 | Long-Run Unit Costs - $/Design Day Dt (1) | $1,103.40 | $156.47 | $258.70 | $1,271.60 | $1,530.30 | $2,790.17 |
| 2 | General Plant Loading Factor | 4.71% | 4.71% | 4.71% | 4.71% | | |
| 3 | Unit Costs + Loading Factor (1)+(1)*(2) | 1,155.39 | 163.85 | 270.89 | 1,331.51 | $1,602.40 | $2,921.64 |
| 4 | | | | | | | |
| 5 | Fixed Charge Rate | 10.95% | 10.95% | 9.63% | 9.63% | | |
| 6 | A & G Exp Plant-Related Loading Factor | 0.22% | 0.22% | 0.22% | 0.22% | | |
| 7 | Total Rate (5)+(6) | 11.18% | 11.18% | 9.86% | 9.86% | | |
| 8 | | | | | | | |
| 9 | Annualized Cost (3)*(7) | $129.16 | $18.32 | $26.70 | $131.23 | $157.93 | $305.41 |
| 10 | | | | | | | |
| 11 | **OPERATING EXPENSES** | | | | | | |
| 12 | Production capacity costs {2} | $2.12 | $0.30 | | | | $2.42 |
| 13 | Distribution capacity costs {3} | | | $0.00 | $27.49 | $27.49 | $27.49 |
| 14 | A&G Exp Non-Plant Loading Factor | 64.11% | 64.11% | 64.11% | 64.11% | | |
| 15 | Total O&M Expense [(12)+(13)]*[1+(14)] | $3.48 | $0.49 | $0.00 | $45.11 | $45.11 | $49.09 |
| 16 | | | | | | | |
| 17 | **WORKING CAPITAL** | | | | | | |
| 18 | Materials & Supplies + Prepayments Rate {4} | 0.11% | 0.11% | 0.11% | 0.11% | | |
| 19 | M&S Cost (3)*(17) | 1.30 | 0.18 | 0.31 | 1.50 | $1.81 | $3.30 |
| 20 | Working Cash O&M Allowance {5} [(9)+(15)]*9.10% | 12.07 | 1.71 | 2.43 | 16.04 | $18.47 | $32.25 |
| 21 | Total Working Capital (19)+(20) | $13.37 | $1.90 | $2.73 | $17.55 | $20.28 | $35.55 |
| 22 | | | | | | | |
| 23 | Working Capital Rev. Req'd {6} (21)*14.27% | $1.91 | $0.27 | $0.39 | $2.50 | $2.89 | $5.07 |
| 24 | | | | | | | |
| 25 | System Seasonal Capacity Related Cost | {9} | | | | | |
| 26 | $/Design Day Dt (9)+(15)+(23) | $0.00 | $19.08 | $27.09 | $178.85 | $205.94 | $225.02 |
| 27 | | | | | | | |
| 28 | Loss Factor {7} | 0.978 | 0.978 | 0.978 | 0.978 | 0.978 | 0.978 |
| 29 | Inflation Adjustment {8} | 5.43% | 5.43% | 5.43% | 5.43% | 5.43% | 5.43% |
| 30 | | | | | | | |
| 31 | **Seasonal Capacity Cost (26)*[1+(28)]/(29)** | $0.00 | $20.58 | $29.22 | $192.89 | $222.11 | $242.69 |

NOTES:

1 Sources: Production taken from Table - 1, Page 1. Distribution taken from Table - 2, page 1.
2 Source: Table - 4, page 4.
3 Source: Table - 5, page 1.
4 Source: Table - 7, page 2.
5 Working cash computed on the basis of 33.21 days net lag.
6 Revenue requirement for working cash computed as the after tax cost of capital, i.e. debt costs plus equity costs increased by taxes equals 14.27%.
7 Source: Table - 7 , page 2.
8 Inflation adjustment to restate marginal costs to rate year dollars.
9 Supply capacity costs set to zero since they are not applicable to delivery marginal costs.

Table - 10
National Grid - New Hampshire
Marginal Cost Study

Summary of Marginal Commodity Costs

| Line No. | Description | Residential ResNonHt R-1 | Residential ResHt R-3&R-4 | Small C&I SmHIW G-41 | Small C&I SmLoW G-51 | Medium C&I MdHIW G-42 | Medium C&I MdLoW G-52 | Large C&I LgHIW G-43 | Large C&I LgLF<90 G-53 | Large C&I LgLF<110 G-54 | Large C&I LgLF>110 G-63 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | PLANT INVESTMENT | | | | | | | | | | |
| 1 | | | | | | | | | | | |
| 2 | | | | | | | | | | | |
| 3 | | | | | | | | | | | |
| 4 | | MARGINAL COMMODITY COSTS NOT COMPUTED FOR DISTRIBUTION MARGINAL COST STUDY | | | | | | | | | |
| 5 | | | | | | | | | | | |
| 6 | | | | | | | | | | | |
| 7 | | | | | | | | | | | |
| 8 | | | | | | | | | | | |
| 9 | | | | | | | | | | | |
| 10 | | | | | | | | | | | |
| 11 | | | | | | | | | | | |
| 12 | | | | | | | | | | | |
| 13 | | | | | | | | | | | |
| 14 | | | | | | | | | | | |
| 15 | | | | | | | | | | | |
| 16 | | | | | | | | | | | |
| 17 | | | | | | | | | | | |
| 18 | | | | | | | | | | | |
| 19 | | | | | | | | | | | |
| 20 | | | | | | | | | | | |
| 21 | | | | | | | | | | | |
| 22 | | | | | | | | | | | |

Table - 41
National Grid - New Hampshire
Marginal Cost Study

**Summary of Marginal Customer Costs**

| Line No. | Description | | Residential ResNonHt R-1 | Residential ResHt R-3&R-4 | Small C&I SmHIW G-41 | Small C&I SmLoW G-51 | Medium C&I MdHIW G-42 | Medium C&I MdLoW G-52 | Large C&I LgHIW G-43 | Large C&I LgLF<90 G-53 | Large C&I LgLF<110 G-54 | Large C&I LgLF>110 G-63 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) |
| | **PLANT INVESTMENT** | | | | | | | | | | | |
| 1 | Meters and Regulators | (1) | $219.07 | $219 07 | $326.65 | $326.65 | $1,255.66 | $1,255.66 | $2,640.66 | $2,640.66 | $11,904.51 | $11,904.51 |
| 2 | General Plant Loading Factor | (2) | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% |
| 3 | Unit Costs + Loading Factor | (1)+(1)*(2) | 229.39 | 229.39 | 342.25 | 342.25 | 1,314.83 | 1,314.83 | 2,765.08 | 2,765.08 | 12,465.45 | 12,465.45 |
| 4 | Fixed Charge Rate | (3) | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% |
| 5 | Meters Carrying Costs | (3)*(4) | 24.08 | 24.08 | 35.93 | 35.93 | 138.02 | 138.02 | 290.25 | 290.25 | 1,308.49 | 1,308.49 |
| 6 | Services | (1) | 1,843.09 | 1,843.09 | 2,276.38 | 2,276.38 | 7,060.41 | 7,060.41 | 8,063.76 | 8,063.76 | 15,605.88 | 15,605.88 |
| 7 | General Plant Loading Factor | (2) | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% | 4.71% |
| 8 | Unit Costs + Loading Factor | (6)+(6)*(7) | 1,929.94 | 1,929.94 | 2,383.65 | 2,383.65 | 7,414.04 | 7,414.04 | 8,443.72 | 8,443.72 | 16,341.23 | 16,341.23 |
| 9 | Fixed Charge Rate | (3) | 9.96% | 9.96% | 9.96% | 9.96% | 9.96% | 9.96% | 9.96% | 9.96% | 9.96% | 9.96% |
| 10 | Services Carrying Costs | (8)*(9) | 192.24 | 192.24 | 237.44 | 237.44 | 738.52 | 738.52 | 841.09 | 841.09 | 1,627.77 | 1,627.77 |
| 11 | | | | | | | | | | | | |
| 12 | Total Plant Carrying Costs | (5)+(10) | $216.32 | $216.32 | $273.36 | $273.36 | $876.54 | $876.54 | $1,131.34 | $1,131.34 | $2,936.27 | $2,935.27 |
| 13 | | | | | | | | | | | | |
| 14 | A & G Exp Plant-Related Loading Factor | (4) | 0.22% | 0.22% | 0.22% | 0.22% | 0.22% | 0.22% | 0.22% | 0.22% | 0.22% | 0.22% |
| 15 | | | | | | | | | | | | |
| 16 | Annualized Cost | (100%+(14))*(12) | $216.81 | $216.81 | $273.98 | $273.98 | $878.51 | $878.51 | $1,133.88 | $1,133.88 | $2,942.85 | $2,942.85 |
| 17 | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | |
| 19 | **OPERATING EXPENSES** | | | | | | | | | | | |
| 20 | Plant Related O&M $/Customer | (5) | $27.19 | $27.19 | $34.32 | $34.32 | $109.90 | $109.90 | $141.12 | $141.12 | $362.68 | $362.68 |
| 21 | Customer Acctg & Mktg Expenses | (6) | $41.29 | $41.29 | $41.29 | $41.29 | $41.29 | $41.29 | $41.29 | $41.29 | $41.29 | $41.29 |
| 22 | A&G Exp Non-Plant Loading Factor | (4) | 64.11% | 64.11% | 64.11% | 64.11% | 64.11% | 64.11% | 64.11% | 64.11% | 64.11% | 64.11% |
| 23 | Total O&M Expense | (20+21+[20+21]*22) | $112.38 | $112.38 | $124.08 | $124.08 | $248.11 | $248.11 | $299.35 | $299.35 | $662.95 | $662.95 |
| 24 | | | | | | | | | | | | |
| 25 | **WORKING CAPITAL - $/Customer** | | | | | | | | | | | |
| 26 | Materials & Supplies + Prepayments Rate (3) | | 0.11% | 0.11% | 0.11% | 0.11% | 0.11% | 0.11% | 0.11% | 0.11% | 0.11% | 0.11% |
| 27 | M&S Cost | [(3)+(8)]*(26) | 2.44 | 2.44 | 3.08 | 3.08 | 9.86 | 9.86 | 12.66 | 12.66 | 32.52 | 32.52 |
| 28 | Working Cash O&M Allowance (7) | [(16)+(34)]*9.10% | 29.95 | 29.95 | 36.22 | 36.22 | 102.50 | 102.50 | 130.40 | 130.40 | 328.06 | 328.06 |
| 29 | Total Working Capital | (27)+(28) | $32.39 | $32.39 | $39.29 | $39.29 | $112.36 | $112.36 | $143.05 | $143.05 | $360.58 | $360.58 |
| 30 | (8) | | | | | | | | | | | |
| 31 | Working Capital Rev. Requirement | (29 14.27% | $4.62 | $4.62 | $5.61 | $5.61 | $16.03 | $16.03 | $20.41 | $20.41 | $51.45 | $51.45 |
| 32 | | | | | | | | | | | | |
| 33 | Annual Customer Related Cost | | $333.80 | $333.80 | $403.67 | $403.67 | $1,142.65 | $1,142.65 | $1,453.64 | $1,453.64 | $3,657.25 | $3,657.25 |
| 34 | $/Customer | (16)+(23)+(31) | | | | | | | | | | |
| 35 | Inflation Adjustment | (9) | 5.43% | 5.43% | 5.43% | 5.43% | 5.43% | 5.43% | 5.43% | 5.43% | 5.43% | 5.43% |
| 36 | | | | | | | | | | | | |
| 37 | **Annual Customer Related Cost (33)*[1+(35)]** | | $351.94 | $351.94 | $425.59 | $425.59 | $1,204.71 | $1,204.71 | $1,532.60 | $1,532.60 | $3,855.90 | $3,855.90 |

NOTES:
1 Meter investment from Table - 3, Page 1.
2 Source: Table - 7, page 2.
3 Source: Table - 8, page 1.
4 Source: Table - 7, page 1.
5 Source: Table - 6, page 2.
6 Source: Table - 6, page 4.
7 Working cash computed on the basis of 33.21 days net lag.
8 Revenue requirement for working cash computed as tax rate divided by 1 minus tax rate multiplied by the cost of equity all added to the cost of capital.
9 Source: Price escalation to mid-point of rate year.

Table - 12
National Grid - New Hampshire
Marginal Cost Study

**Summary of Marginal Cost Estimates**

| Line No. | Description | | Residential ResNonHt R-1 | Residential ResHt R-3&R-4 | Small C&I SmHIW G-41 | Small C&I SmLoW G-51 | Medium C&I MdHIW G-42 | Medium C&I MdLoW G-52 | Large C&I LgHIW G-43 | Large C&I LgLF<90 G-53 | Large C&I LgLF<110 G-54 | Large C&I LgLF>110 G-63 | Total Company |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
| 1 | UNCOLLECTIBLE FACTOR | | 5.41% | 4.46% | 0.74% | 0.80% | 0.23% | 0.14% | 0.00% | 0.00% | 0.00% | 0.00% | |
| 2 | | | | | | | | | | | | | |
| 3 | CUSTOMER CHARGE $'s per month | (1) | | | | | | | | | | | |
| 4 | Customer Charge w/o Uncollectibles | | $29.33 | $29.33 | $35.47 | $35.47 | $100.39 | $100.39 | $127.72 | $127.72 | $321.32 | $321.32 | |
| 5 | Adjustment for Uncollectibles | (1)*(4) | 1.59 | 1.31 | 0.26 | 0.28 | 0.23 | 0.14 | 0.00 | 0.00 | 0.00 | 0.00 | |
| 6 | Customer Charge Incl. Uncollectibles | (4)+(5) | $30.92 | $30.63 | $35.73 | $35.75 | $100.62 | $100.53 | $127.72 | $127.72 | $321.32 | $321.32 | |
| 7 | | | | | | | | | | | | | |
| 8 | WINTER CHARGES | | | | | | | | | | | | |
| 9 | Gas Supply Demand Charge, Design Day, Dt | (2) | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | |
| 10 | Delivery Demand Charge - Pressure Support | (2) | 20.58 | 20.58 | 20.58 | 20.58 | 20.58 | 20.58 | 20.58 | 20.58 | 20.58 | 20.58 | |
| 11 | Delivery Demand Charge - Reinforcements | (2) | 29.22 | 29.22 | 29.22 | 29.22 | 29.22 | 29.22 | 29.22 | 29.22 | 29.22 | 29.22 | |
| 12 | Delivery Demand Charge - Main Extensions | (2) | 192.89 | 192.89 | 192.89 | 192.89 | 192.89 | 192.89 | 192.89 | 192.89 | 192.89 | 192.09 | |
| 13 | Adjustment for Uncollectibles | [(9)+(10)+(11)+(12)]*(1) | $13.14 | $10.81 | $1.80 | $1.94 | $0.56 | $0.34 | $0.00 | $0.00 | $0.00 | $0.00 | |
| 14 | Winter Charges Incl. Uncollectibles | (13)+(14) | $255.83 | $253.50 | $244.49 | $244.62 | $243.24 | $243.02 | $242.69 | $242.69 | $242.69 | $242.69 | |
| 15 | | | | | | | | | | | | | |
| 16 | Supply Commodity Charge $'s per Dt | (3) | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | |
| 17 | Adjustment for Uncollectibles | (1)*(16) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | |
| 18 | Supply Commodity Charge Incl. Uncollectibles | (17)+(18) | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | |
| 19 | | | | | | | | | | | | | |
| 20 | SUMMER CHARGES | | | | | | | | | | | | |
| 21 | Demand Charge $'s per Design Day Dt | (2) | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | |
| 22 | Delivery Demand Charge | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | |
| 23 | Adjustment for Uncollectibles | [(21)+(22)]*(1) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | |
| 24 | Summer Charges Incl. Uncollectibles | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | |
| 25 | | | | | | | | | | | | | |
| 26 | Commodity Charge $'s per Dt | (3) | $0.00 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | |
| 27 | Adjustment for Uncollectibles | (1)*(26) | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | |
| 28 | Commodity Charge Incl. Uncollectibles | (26)+(27) | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | |
| 29 | | | | | | | | | | | | | |
| 30 | CALENDAR MONTH BILLING DETERMINANTS | (2006) | | | | | | | | | | | |
| 31 | Customers | | 4,975 | 67,751 | 7,277 | 1,356 | 1,464 | 300 | 43 | 38 | 1 | 16 | 83,221 |
| 32 | Design Day Dt -Sales & Transp | | 736 | 60,766 | 21,832 | 2,750 | 32,305 | 3,870 | 5,178 | 5,085 | 82 | 2,678 | 135,482 |
| 33 | Winter Dt -Sales & Transp | | 74,694 | 4,825,542 | 1,604,827 | 265,993 | 2,540,441 | 422,970 | 424,067 | 503,546 | 11,704 | 543,924 | 11,297,707 |
| 34 | Summer Dt -Sales & Transp | | 40,806 | 1,141,908 | 264,385 | 136,104 | 589,998 | 256,451 | 125,733 | 398,264 | 11,165 | 774,303 | 3,739,197 |
| 35 | | | | | | | | | | | | | |
| 36 | REVENUES RESULTING FROM FULL MARGINAL COST PRICING | | | | | | | | | | | | |
| 37 | Total Customer Related | (6)*(31)*12 Mos. | $1,845,794 | $24,906,214 | $3,120,192 | $581,764 | $1,767,908 | $361,576 | $65,208 | $58,707 | $3,974 | $61,523 | 32,772,860 |
| 38 | | | | | | | | | | | | | |
| 39 | Winter | | | | | | | | | | | | |
| 40 | Winter Supply Capacity Cost | (1+(1))*(9)*(32) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 41 | Winter Delivery Pressure Support | (1+(1))*(10)*(32) | 15,961 | 1,306,253 | 452,615 | 57,045 | 666,343 | 79,759 | 106,556 | 104,644 | 1,686 | 59,218 | 2,850,078 |
| 42 | Winter Delivery Reinforcements | (1+(1))*(11)*(32) | 22,659 | 1,854,451 | 642,565 | 80,986 | 945,988 | 113,231 | 151,274 | 148,560 | 2,394 | 84,070 | 4,046,178 |
| 43 | Winter Delivery Main Ext. | (1+(1))*(12)*(32) | 149,601 | 12,243,643 | 4,242,410 | 534,691 | 6,245,697 | 747,586 | 998,756 | 980,836 | 15,806 | 555,053 | 26,714,079 |
| 44 | Winter Supply Commodity | (1+(1))*(18)*(33) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 45 | Total Winter | (40)+(41)+(42)+(43)+(44) | $188,221 | $15,404,347 | $5,337,591 | $672,722 | $7,858,028 | $940,576 | $1,256,586 | $1,234,040 | $19,886 | $698,340 | $33,610,335 |
| 46 | | | | | | | | | | | | | |
| 47 | Summer | | | | | | | | | | | | |
| 48 | Summer Supply Demand | (1+(1))*(21)*(32) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 49 | Delivery Demand Charge | (1+(1))*(22)*(34) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 50 | Summer Supply Commodity | (1+(1))*(26)*(34) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 51 | Total Summer | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 52 | | | | | | | | | | | | | |
| 53 | Customer Subtotal | (37) | 1,845,794 | 24,906,214 | 3,120,192 | 581,764 | 1,767,908 | 361,576 | 65,208 | 58,707 | 3,974 | 61,523 | $32,772,860 |
| 54 | Supply Subtotal | (40)+(44)+(48)+(50) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 55 | Delivery Subtotal | (41)+(42)+(43)+(49) | 188,221 | 15,404,347 | 5,337,591 | 672,722 | 7,858,028 | 940,576 | 1,256,586 | 1,234,040 | 19,886 | 698,340 | 33,610,335 |
| 56 | Total Marginal Annual Cost | | $2,034,015 | $40,310,561 | $8,457,783 | $1,254,486 | $9,625,936 | $1,302,151 | $1,321,794 | $1,292,747 | $23,860 | $759,863 | $66,383,195 |

NOTES:
1 Source: Table 11, page 1, line (37)/12
2 Source: Table - 9, page 1
3 Source: Table - 10, page 1

Table - 13
National Grid - New Hampshire
Marginal Cost Study

**Marginal Unit Costs per Dt**

| Line No. | Description | | Residential | | Small C&I | | Medium C&I | | Large C&I | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ResNonHt R-1 | ResHt R-3&R-4 | SmHIW G-41 | SmLoW G-51 | MdHIW G-42 | MdLoW G-52 | LgHIW G-43 | LgLF<90 G-53 | LgLF<110 G-54 | LgLF>110 G-63 | Total Company |
| | (1) | | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
| 1 | CUSTOMER CHARGE | | | | | | | | | | | | |
| 2 | Customer Charge (w/ Uncoll) | $'s per Month | $30.916 | $30.635 | $35.729 | $35.749 | $100.623 | $100.532 | $127.716 | $127.716 | $321.325 | $321.325 | |
| 3 | | | | | | | | | | | | | |
| 4 | | | | | | | | | | | | | |
| 5 | WINTER CHARGES | (1) | | | | | | | | | | | |
| 6 | Winter Supply Capacity Cost | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 7 | Winter Delivery Pressure Support | | $0.2137 | $0.2707 | $0.2820 | $0.2145 | $0.2623 | $0.1886 | $0.2513 | $0.1793 | $0.1441 | $0.1089 | |
| 8 | Winter Delivery Reinforcements | | $0.3034 | $0.3843 | $0.4004 | $0.3045 | $0.3724 | $0.2677 | $0.3567 | $0.2546 | $0.2045 | $0.1546 | |
| 9 | Winter Delivery Main Ext. | | $2.0029 | $2.5373 | $2.6435 | $2.0102 | $2.4585 | $1.7675 | $2.3552 | $1.6808 | $1.3505 | $1.0205 | |
| 10 | Winter Supply Commodity | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 11 | | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | | |
| 13 | SUMMER CHARGES | (1) | | | | | | | | | | | |
| 14 | Supply Demand Charge | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 15 | Delivery Demand Charge | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 16 | Commodity Charge | $'s per Dt | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 17 | | | | | | | | | | | | | |
| 18 | **TOTAL CHARGES** | | | | | | | | | | | | |
| 19 | Supply Costs | | | | | | | | | | | | |
| 20 | Customer | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | |
| 21 | Winter, $/Dt | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 22 | Summer, $/Dt | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 23 | Annual Avg, $/Dt | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 24 | | | | | | | | | | | | | |
| 25 | Delivery | | | | | | | | | | | | |
| 26 | Customer | (2) | $30.92 | $30.63 | $35.73 | $35.75 | $100.62 | $100.53 | $127.72 | $127.72 | $321.32 | $321.32 | |
| 27 | Winter, $/Dt | (7)+(8)+(9) | $2.5199 | $3.1923 | $3.3260 | $2.5291 | $3.0932 | $2.2237 | $2.9632 | $2.1147 | $1.6991 | $1.2839 | |
| 28 | Summer, $/Dt | (15) | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 29 | Annual Avg, $/Dt | | $1.6296 | $2.5814 | $2.8555 | $1.6727 | $2.5102 | $1.3844 | $2.2855 | $1.2560 | $0.8695 | $0.5298 | |
| 30 | | | | | | | | | | | | | |
| 31 | TEST YEAR CALENDAR MONTH BILLING DETERMINANTS - SALES and TRANSPORTATION LOADS (All Firm Loads) | | | | | | | | | | | | |
| 32 | Customers | | 4,975 | 67,751 | 7,277 | 1,356 | 1,464 | 300 | 43 | 38 | 1 | 16 | 83,221 |
| 33 | Design Day Dt | | 736 | 60,766 | 21,832 | 2,750 | 32,305 | 3,870 | 5,178 | 5,085 | 82 | 2,878 | 135,482 |
| 34 | Winter Dt | | 74,694 | 4,825,542 | 1,604,827 | 265,993 | 2,540,441 | 422,970 | 424,067 | 583,546 | 11,704 | 543,924 | 11,297,707 |
| 35 | Summer Dt | | 40,806 | 1,141,908 | 264,385 | 136,184 | 589,998 | 256,451 | 125,733 | 398,264 | 11,165 | 774,303 | 3,739,197 |
| 36 | Total Annual Dt | | 115,499 | 5,967,450 | 1,869,213 | 402,177 | 3,130,439 | 679,420 | 549,800 | 981,810 | 22,869 | 1,318,227 | 15,036,904 |

NOTES:
1 Source: Table - 12 revenues divided by billing month normalized determinants.

Table - 14
National Grid - New Hampshire
Marginal Cost Study

**Derivation of Marginal Prices Equi-Porportionately Constrained by Embedded Costs**

| Line No. | Description | | Residential ResNonHt R-1 | Residential ResHt R-3&R-4 | Small C&I SmHiW G-41 | Small C&I SmLoW G-51 | Medium C&I MdHiW G-42 | Medium C&I MdLoW G-52 | Large C&I LgHiW G-43 | Large C&I LgLF<90 G-53 | Large C&I LgLF<110 G-54 | Large C&I LgLF>110 G-63 | Total Company |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
| 1 | Estimated Delivery Revenue Reqm'ts | (1) | | | | | | | | | | | $49,633,399 |
| 2 | Total Marginal Annual Revenue Requirements | (2) | 2,034,015 | 40,310,561 | 8,457,783 | 1,254,486 | 9,625,936 | 1,302,151 | 1,321,794 | 1,292,747 | 23,860 | 759,863 | 66,383,195 |
| 3 | Difference | (1) - (2) | | | | | | | | | | | (16,749,796) |
| 4 | % Difference | (3)/(2) | | | | | | | | | | | -25.23% |
| 5 | Equi-proportional Adjustment | (2) x (4) | (513,222) | (10,171,154) | (2,134,066) | (316,532) | (2,428,814) | (328,559) | (333,515) | (326,186) | (6,020) | (191,728) | (16,749,796) |
| 6 | Marginal Cost Constained to Allowed Revenues | (2) + (5) | 1,520,793 | 30,139,407 | 6,323,717 | 937,954 | 7,197,122 | 973,593 | 988,279 | 966,561 | 17,839 | 568,134 | 49,633,399 |
| 7 | | | | | | | | | | | | | |
| 8 | Marginal Unit Prices | Unit Costs from | | | | | | | | | | | |
| 9 | Customer | Table 14 X | $23.12 | $22.90 | $26.71 | $26.73 | $75.23 | $75.17 | $95.49 | $95.49 | $240.25 | $240.25 | |
| 10 | | [1+ (4)] | | | | | | | | | | | |
| 11 | WINTER CHARGES | | | | | | | | | | | | |
| 12 | Winter Supply Capacity Cost | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 13 | Winter Delivery Pressure Support | | $0.1598 | $0.2024 | $0.2109 | $0.1603 | $0.1961 | $0.1410 | $0.1879 | $0.1341 | $0.1077 | $0.0814 | |
| 14 | Winter Delivery Reinforcements | | $0.2268 | $0.2873 | $0.2994 | $0.2276 | $0.2784 | $0.2002 | $0.2667 | $0.1903 | $0.1529 | $0.1156 | |
| 15 | Winter Delivery Main Ext. | | $1.4975 | $1.8971 | $1.9765 | $1.5030 | $1.8382 | $1.3215 | $1.7609 | $1.2567 | $1.0097 | $0.7630 | |
| 16 | Winter Supply Commodity | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 17 | | | $1.8841 | $2.3868 | $2.4868 | $1.8910 | $2.3127 | $1.6626 | $2.2155 | $1.5811 | $1.2704 | $0.9599 | |
| 18 | | | | | | | | | | | | | |
| 19 | SUMMER CHARGES | | | | | | | | | | | | |
| 20 | Supply Demand Charge | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 21 | Delivery Demand Charge | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 22 | Commodity Charge $'s per Dt | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 23 | | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 24 | TOTAL CHARGES | | | | | | | | | | | | |
| 25 | Supply Costs | | | | | | | | | | | | |
| 26 | Customer | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | |
| 27 | Winter, $/Dt | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 28 | Summer, $/Dt | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 29 | Annual Avg. $/Dt | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 30 | | | | | | | | | | | | | |
| 31 | | | | | | | | | | | | | |
| 32 | Delivery | | | | | | | | | | | | |
| 33 | Customer Charges | | $23.12 | $22.90 | $26.71 | $26.73 | $75.23 | $75.17 | $95.49 | $95.49 | $240.25 | $240.25 | |
| 34 | Winter, $/Dt | | $1.8841 | $2.3868 | $2.4868 | $1.8910 | $2.3127 | $1.6626 | $2.2155 | $1.5811 | $1.2704 | $0.9599 | |
| 35 | Summer, $/Dt | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| 36 | Annual Avg. $/Dt | | $1.2184 | $1.9301 | $2.1350 | $1.2506 | $1.8768 | $1.0351 | $1.7088 | $0.9398 | $0.6501 | $0.3961 | |
| 37 | or | | | | | | | | | | | | |
| 38 | Facilities Charge, $/Month | (6) / Annual bill $ | 25.47 | $ 37.07 | $ 72.41 | $ 57.64 | $ 409.63 | $ 270.70 | $ 1,935.65 | $ 2,102.74 | $ 1,442.55 | $ 2,967.27 | |

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**National Grid NH**
**Rate Design**
**Summary of Indirect Gas Costs**

Attachment GLG-RD-4-1
National Grid NH
DG 08-009
Page 1 of 1

| Line No. | Description | Non-Heat | Heat | Low Income | Small High Winter Use | Med High Winter Use | Large High Winter Use | Small Low Winter Use | Med Low Winter Use | Large Load Factor <90% | Large Load Factor <110% | Large Load Factor >110% | Total | *Large Load Factor >90%* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Rate Designation | RNSH R-1 | RSH R-3 | RLIAP R-4 | SH G-41 | MH G-42 | LH G-43 | SL G-51 | ML G-52 | LLL90 G-53 | LLL110 G-54 | LLG110 G-63 | | *LLG90 G-54 + G-63* |
| 1 | LP and LNG Costs | | | | | | | | | | | | 1,669,226 | |
| 2 | Sales Volumes | 1,154,994 | 55,740,602 | 3,933,900 | 17,256,815 | 25,685,378 | 2,821,982 | 3,673,917 | 5,410,375 | 964,872 | 11,410 | 355,465 | 117,009,709 | 366,874 |
| 3 | Unit Cost in COGC | | | | | | | | | | | | $ 0.01600 | |
| 4 | Class Revenues | 18,480 | 891,850 | 62,942 | 276,109 | 410,966 | 45,152 | 58,783 | 86,566 | 15,438 | 183 | 5,687 | 1,872,155 | 5,870 |
| 5 | | | | | | | | | | | | | | |
| 6 | Bad Debt Costs | | | | | | | | | | | | 3,340,075 | |
| 7 | Sales Volumes | 1,154,994 | 55,740,602 | 3,933,900 | 17,256,815 | 25,685,378 | 2,821,982 | 3,673,917 | 5,410,375 | 964,872 | 11,410 | 355,465 | 117,009,709 | 366,874 |
| 8 | Unit Cost in COGC | | | | | | | | | | | | $ 0.02850 | |
| 9 | Class Revenues | 32,917 | 1,588,607 | 112,116 | 491,819 | 732,033 | 80,426 | 104,707 | 154,196 | 27,499 | 325 | 10,131 | 3,334,777 | 10,456 |
| 10 | | | | | | | | | | | | | | |
| 11 | Gas Working Capital | | | | | | | | | | | | 695,079 | |
| 12 | Sales Volumes | 1,154,994 | 55,740,602 | 3,933,900 | 17,256,815 | 25,685,378 | 2,821,982 | 3,673,917 | 5,410,375 | 964,872 | 11,410 | 355,465 | 117,009,709 | 366,874 |
| 13 | Unit Cost in COGC | | | | | | | | | | | | $ 0.00590 | |
| 14 | Class Revenues | 6,814 | 328,870 | 23,210 | 101,815 | 151,544 | 16,650 | 21,676 | 31,921 | 5,693 | 67 | 2,097 | 690,357 | 2,165 |
| 15 | | | | | | | | | | | | | | |
| 16 | Other A&G and Misc. | | | | | | | | | | | | 56,975 | |
| 17 | Sales Volumes | 1,154,994 | 55,740,602 | 3,933,900 | 17,256,815 | 25,685,378 | 2,821,982 | 3,673,917 | 5,410,375 | 964,872 | 11,410 | 355,465 | 117,009,709 | 366,874 |
| 18 | Unit Cost in COGC | | | | | | | | | | | | $ 0.00050 | |
| 19 | Class Revenues | 577 | 27,870 | 1,967 | 8,628 | 12,843 | 1,411 | 1,837 | 2,705 | 482 | 6 | 178 | 58,505 | 183 |
| 20 | | | | | | | | | | | | | | |
| 21 | Total Indirect Gas Costs | 58,789 | 2,837,197 | 200,235 | 878,372 | 1,307,386 | 143,639 | 187,002 | 275,388 | 49,112 | 581 | 18,093 | 5,955,794 | 18,674 |
| 22 | | | | | | | | | | | | | | |
| 23 | Total from Attachment GLG-2-3, pg 1 | | | | | | | | | | | | 5,961,355 | |
| 24 | | | | | | | | | | | | | | |
| 25 | Variance, $s | | | | | | | | | | | | (5,561) | |
| 26 | | | | | | | | | | | | | | |
| 27 | Variance, % | | | | | | | | | | | | -0.09% | |

EN Rate Design - Final.xls Indirect Gas Costs

**National Grid NH**
**Rate Design**
**Derivation of Revnue Targets**



| Line No. | Description | Non-Heat | Heat | Low Income | Small High Winter Use | Med High Winter Use | Large High Winter Use | Small Low Winter Use | Med Low Winter Use | Large Load Factor <90% | Large Load Factor <110% | Large Load Factor >110% | Total | *Large Load Factor >90%* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Rate Designation | RNSH R-1 | RSH R-3 | RLIAP R-4 | SH G-41 | MH G-42 | LH G-43 | SL G-51 | ML G-52 | LLL90 G-53 | LLL110 G-54 | LLG110 G-63 | | *LLG90 G-54 + G-63* |
| 1 | **Rate Design Parameters** | | | | | | | | | | | | | |
| 2 | Rate Cap on Class Revenue Targets | | | | | | | | | | | | 125% | |
| 3 | | | | | | | | | | | | | | |
| 4 | **Calendar Month Billing Determinants (Dry)** | | | | | | | | | | | | | |
| 5 | Number of Annual Bills - Sales & Delivery Svc | 59,704 | 758,648 | 54,356 | 87,330 | 17,570 | 511 | 16,274 | 3,597 | 460 | 12 | 191 | 998,654 | *204* |
| 6 | Total Annual Therms - Sales & Delivery Svc | 1,154,994 | 55,740,602 | 3,933,900 | 18,692,125 | 31,304,390 | 5,497,997 | 4,021,769 | 6,794,203 | 9,818,096 | 228,693 | 13,182,269 | 150,369,039 | *13,410,962* |
| 7 | Winter | 746,936 | 45,070,549 | 3,184,873 | 16,048,271 | 25,404,411 | 4,240,672 | 2,659,928 | 4,229,696 | 5,835,457 | 117,040 | 5,439,240 | 112,977,070 | *5,556,279* |
| 8 | Summer | 408,059 | 10,670,053 | 749,027 | 2,643,854 | 5,899,979 | 1,257,325 | 1,361,841 | 2,564,508 | 3,982,639 | 111,654 | 7,743,029 | 37,391,968 | *7,854,683* |
| 9 | | | | | | | | | | | | | | |
| 10 | **Test Year Delivery Revenues - Assume No R-4 Discount.** | | | | | | | | | | | | | |
| 11 | Customer Charge | 412,551 | 7,495,444 | 535,787 | 2,151,804 | 1,218,634 | 152,859 | 403,749 | 249,211 | 137,900 | 3,710 | 57,440 | 12,820,089 | *61,150* |
| 12 | Total Annual Therms - Sales & Delivery Svc | 283,295 | 13,885,129 | 987,603 | 4,383,126 | 6,493,797 | 752,716 | 737,801 | 848,019 | 816,764 | 13,687 | 327,636 | 29,529,573 | *341,324* |
| 13 | Winter | 181,389 | 11,330,588 | 815,490 | 3,778,846 | 5,247,085 | 662,817 | 481,152 | 584,628 | 615,641 | 9,188 | 184,390 | 23,891,214 | *193,578* |
| 14 | Summer | 101,906 | 2,554,542 | 172,113 | 604,279 | 1,246,712 | 89,899 | 256,649 | 263,390 | 201,123 | 4,500 | 143,246 | 5,638,359 | *147,746* |
| 15 | Total Revenue | 695,846 | 21,380,573 | 1,524,390 | 6,534,929 | 7,712,431 | 905,574 | 1,141,550 | 1,097,229 | 954,664 | 17,397 | 385,076 | 42,349,662 | *402,474* |
| 16 | | | | | | | | | | | | | | |
| 17 | **Pure Marginal Cost Based Rates** | | | | | | | | | | | | | |
| 18 | Facilities Charge per Month | $25.47 | $37.07 | $37.07 | $72.41 | $409.63 | $1,935.65 | $57.64 | $270.70 | $2,102.74 | $1,442.55 | $2,967.27 | | |
| 19 | Annual Bills | 59,704 | 758,648 | 54,358 | 87,330 | 17,570 | 511 | 16,274 | 3,597 | 460 | 12 | 191 | | |
| 20 | | | | | | | | | | | | | | |
| 21 | **Marginal Costs to Serve** | | | | | | | | | | | | | |
| 22 | Marginal Costs for Delivery Service | $1,520,793 | $28,124,266 | $2,015,142 | $6,323,717 | $7,197,122 | $988,279 | $937,954 | $973,593 | $966,561 | $17,839 | $568,134 | 49,633,399 | *585,974* |
| 23 | | | | | | | | | | | | | | |
| 24 | **Revenue Target Calculation** | | | | | | | | | | | | | |
| 25 | Marginal Cost to Serve | 1,520,793 | 28,124,266 | 2,015,142 | 6,323,717 | 7,197,122 | 988,279 | 937,954 | 973,593 | 966,561 | 17,839 | 568,134 | 49,633,399 | *585,974* |
| 26 | Present Revenue | 695,846 | 21,380,573 | 1,524,390 | 6,534,929 | 7,712,431 | 905,574 | 1,141,550 | 1,097,229 | 954,664 | 17,397 | 385,076 | 42,349,662 | *402,474* |
| 27 | Increase without Consideration of Impact | 824,947 | 6,743,693 | 490,751 | (211,213) | (515,310) | 82,705 | (203,596) | (123,637) | 11,897 | 442 | 183,058 | 7,283,737 | *183,500* |
| 28 | Percentage Increase to Achieve Marginal Cost | 118.55% | 31.54% | 32.19% | -3.23% | -6.68% | 9.13% | -17.84% | -11.27% | 1.25% | 2.54% | 47.54% | 17.20% | *45.59%* |
| 29 | Rate Cap to Control Impact (Multiplier to Avg Increase) | 125.00% | 125.00% | 125.00% | 125.00% | 125.00% | 125.00% | 125.00% | 125.00% | 125.00% | 125.00% | 125.00% | 125.00% | *125.00%* |
| 30 | Maximum Percentage Increase (Cap) | 21.50% | 21.50% | 21.50% | 21.50% | 21.50% | 21.50% | 21.50% | 21.50% | 21.50% | 21.50% | 21.50% | 21.50% | *21.50%* |
| 31 | Maximum Revenues Applying Cap | 845,445 | 25,977,141 | 1,852,116 | 7,939,861 | 9,370,512 | 1,100,262 | 1,386,970 | 1,333,121 | 1,159,905 | 21,137 | 467,863 | 51,454,333 | *489,001* |
| 32 | | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | | |
| 34 | | | | | | | | | | | | | | |

**National Grid NH**
**Rate Design**
**Derivation of Revnue Targets**



| Line No. | Description | Non-Heat | Heat | Low Income | Small High Winter Use | Med High Winter Use | Large High Winter Use | Small Low Winter Use | Med Low Winter Use | Large Load Factor <90% | Large Load Factor <110% | Large Load Factor >110% | Total | *Large Load Factor >90%* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Rate Designation | RNSH R-1 | RSH R-3 | RLIAP R-4 | SH G-41 | MH G-42 | LH G-43 | SL G-51 | ML G-52 | LLL90 G-53 | LLL110 G-54 | LLG110 G-63 | | *LLG90 G-54 + G-63* |
| 35 | **First Iteration** | | | | | | | | | | | | | |
| 36 | Rates Limited by Cap - First Iteration | 845,445 | 25,977,141 | 1,852,116 | - | - | - | - | - | - | - | 467,863 | 29,142,565 | *489,001* |
| 37 | Subsidy Required from Other Classes | 675,348 | 2,147,125 | 163,026 | - | - | - | - | - | - | - | 100,271 | 3,085,769 | *96,973* |
| 38 | Marginal Cost of Rates Not Subject to Cap | - | - | - | 6,323,717 | 7,197,122 | 988,279 | 937,954 | 973,593 | 966,561 | 17,839 | - | 17,405,064 | - |
| 39 | Allocation of Subsidies to Uncapped Classes | - | - | - | 1,121,141 | 1,275,988 | 175,213 | 166,291 | 172,610 | 171,363 | 3,163 | - | 3,085,769 | - |
| 40 | First Iteration -Revised Revenue Targets | 845,445 | 25,977,141 | 1,852,116 | 7,444,857 | 8,473,110 | 1,163,492 | 1,104,245 | 1,146,202 | 1,137,924 | 21,002 | 467,863 | 49,633,399 | *489,001* |
| 41 | | | | | | | | | | | | | | |
| 42 | **Second Iteration** | | | | | | | | | | | | | |
| 43 | Rates Limited by Cap - Second Iteration | 845,445 | 25,977,141 | 1,852,116 | - | - | 1,100,262 | - | - | - | - | 467,863 | 30,242,827 | *489,001* |
| 44 | Subsidy Required from Other Classes | - | - | - | - | - | 63,230 | - | - | - | - | - | 63,230 | - |
| 45 | Marginal Cost of Rates Not Subject to Cap | - | - | - | 7,444,857 | 8,473,110 | - | 1,104,245 | 1,146,202 | 1,137,924 | 21,002 | - | 19,327,341 | - |
| 46 | Allocation of Subsidies to Uncapped Classes | - | - | - | 24,356 | 27,720 | - | 3,613 | 3,750 | 3,723 | 69 | - | 63,230 | - |
| 47 | Second Iteration -Revised Revenue Targets | 845,445 | 25,977,141 | 1,852,116 | 7,469,214 | 8,500,830 | 1,100,262 | 1,107,858 | 1,149,952 | 1,141,647 | 21,071 | 467,863 | 49,633,399 | *489,001* |
| 48 | | | | | | | | | | | | | | |
| 49 | **Third Iteration** | | | | | | | | | | | | | |
| 50 | Rates Limited by Cap - Third Iteration | 845,445 | 25,977,141 | 1,852,116 | - | - | 1,100,262 | - | - | - | - | 467,863 | 30,242,827 | *489,001* |
| 51 | Subsidy Required from Other Classes | - | - | - | - | - | - | - | - | - | - | - | 0 | - |
| 52 | Marginal Cost of Rates Not Subject to Cap | - | - | - | 7,469,214 | 8,500,830 | - | 1,107,858 | 1,149,952 | 1,141,647 | 21,071 | - | 19,390,572 | - |
| 53 | Allocation of Subsidies to Uncapped Classes | - | - | - | - | - | - | - | - | - | - | - | 0 | - |
| 54 | Third Iteration -Revised Revenue Targets | 845,445 | 25,977,141 | 1,852,116 | 7,469,214 | 8,500,830 | 1,100,262 | 1,107,858 | 1,149,952 | 1,141,647 | 21,071 | 467,863 | 49,633,399 | *489,001* |
| 55 | | | | | | | | | | | | | | |
| 56 | **Eliminate Decreases** | | | | | | | | | | | | | |
| 57 | Eliminate Decreases | | | | | | | | | | | | | |
| 58 | Inrease Over Present Rates after Third Iteration | 149,599 | 4,596,568 | 327,726 | 934,284 | 788,399 | 194,688 | (33,692) | 52,723 | 186,983 | 3,674 | 82,787 | 7,283,737 | *86,527* |
| 59 | Percent Increase | 21.50% | 21.50% | 21.50% | 14.30% | 10.22% | 21.50% | -2.95% | 4.81% | 19.59% | 21.12% | 21.50% | 17.20% | *21.50%* |
| 60 | Classes With Dereases | - | - | - | - | - | - | (33,692) | - | - | - | - | (33,692) | - |
| 61 | Classes With Increases Less than Cap | - | - | - | 7,469,214 | 8,500,830 | - | - | 1,149,952 | 1,141,647 | 21,071 | - | 18,282,714 | - |
| 62 | Allocation of Decreases | - | - | - | (13,764) | (15,666) | - | - | (2,119) | (2,104) | (39) | - | (33,692) | - |
| 63 | | | | | | | | | | | | | | |
| 64 | **Final Revenue Targets** | | | | | | | | | | | | | |
| 65 | Final Revenue Target | 845,445 | 25,977,141 | 1,852,116 | 7,455,449 | 8,485,164 | 1,100,262 | 1,141,550 | 1,147,833 | 1,139,543 | 21,032 | 467,863 | 49,633,399 | *489,001* |
| 66 | Inrease Over Present Rates after Third Iteration | 149,599 | 4,596,568 | 327,726 | 920,520 | 772,733 | 194,688 | - | 50,604 | 184,879 | 3,635 | 82,787 | 7,283,737 | *86,527* |
| 67 | Percent Increase | 21.50% | 21.50% | 21.50% | 14.09% | 10.02% | 21.50% | 0.00% | 4.61% | 19.37% | 20.89% | 21.50% | 17.20% | *21.50%* |

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**National Grid NH**
**Rate Design**
**Rate Design Calculations**

Attachment GLG-RD-4-3
National Grid NH
DG 08-009


| Line No. | Description | Non-Heat | Heat | Low Income | Small High Winter Use | Med High Winter Use | Large High Winter Use | Small Low Winter Use | Med Low Winter Use | Large Load Factor <90% | Large Load Factor <110% | Large Load Factor >110% | Total | *Large Load Factor >90%* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Rate Designation | RNSH<br>R-1 | RSH<br>R-3 | RLIAP<br>R-4 | SH<br>G-41 | MH<br>G-42 | LH<br>G-43 | SL<br>G-51 | ML<br>G-52 | LLL90<br>G-53 | LLL110<br>G-54 | LLG110<br>G-63 | | *LLG90*<br>*G-54 + G-63* |
| 1 | **Rate Design Parameters** | | | | | | | | | | | | | |
| 2 | Rate Cap on Rate Customer Charge | | | | | | | | | | | | 100% | |
| 3 | Revenue Targets | 845,446 | 25,977,141 | 1,852,116 | 7,455,449 | 8,485,164 | 1,100,262 | 1,141,550 | 1,147,833 | 1,139,543 | 21,032 | 467,863 | 49,633,399 | *488,895* |
| 4 | | | | | | | | | | | | | | |
| 5 | **Equivalent Present Rates - No R-4 Discount - Dry Therms** | | | | | | | | | | | | | |
| 6 | Headblock Size | | | | | | | | | | | | | |
| 7 | Winter | 10 | 100 | 100 | 100 | 1,000 | 0 | 100 | 1,000 | 0 | 0 | 0 | | |
| 8 | Summer | 10 | 20 | 20 | 20 | 400 | 0 | 100 | 1,000 | 0 | 0 | 0 | | |
| 9 | Customer Charge | $ 6.91 | $ 9.88 | $ 9.88 | $ 24.64 | $ 69.36 | $ 299.39 | $ 24.81 | $ 69.29 | $ 300.00 | $ 300.00 | $ 300.00 | | *$ 300.00* |
| 10 | Current Winter Head Block Rate | $ 0.26314 | $ 0.28938 | $ 0.28938 | $ 0.32180 | $ 0.26687 | $ 0.15633 | $ 0.24811 | $ 0.17038 | $ 0.10553 | $ 0.07851 | $ 0.03390 | | |
| 11 | Current WinterTail Block Rate | $ 0.23229 | $ 0.16812 | $ 0.16812 | $ 0.20929 | $ 0.17628 | $ 0.15633 | $ 0.16026 | $ 0.11565 | $ 0.10553 | $ 0.07851 | $ 0.03390 | | |
| 12 | Current Summer Head Block Rate | $ 0.26314 | $ 0.28938 | $ 0.28938 | $ 0.32180 | $ 0.26687 | $ 0.07153 | $ 0.24811 | $ 0.12528 | $ 0.05051 | $ 0.04029 | $ 0.01847 | | |
| 13 | Current SummerTail Block Rate | $ 0.23229 | $ 0.16812 | $ 0.16812 | $ 0.20929 | $ 0.17628 | $ 0.07153 | $ 0.16026 | $ 0.07212 | $ 0.05051 | $ 0.04029 | $ 0.01847 | | |
| 14 | | | | | | | | | | | | | | |
| 15 | **Billing Determinants (Dry)** | | | | | | | | | | | | | |
| 16 | Number of Annual Bills - Sales & Delivery Svc | 59,704 | 758,648 | 54,358 | 87,330 | 17,570 | 511 | 16,274 | 3,597 | 460 | 12 | 191 | 998,654 | *204* |
| 17 | Winter | 29,521 | 379,317 | 26,528 | 43,909 | 8,727 | 268 | 8,107 | 1,792 | 229 | 6 | 98 | 498,500 | *103* |
| 18 | Summer | 30,183 | 379,332 | 27,830 | 43,421 | 8,843 | 243 | 8,166 | 1,805 | 231 | 7 | 94 | 500,154 | *100* |
| 19 | Total Annual Therms - Sales & Delivery Svc | 1,154,994 | 55,740,602 | 3,933,900 | 18,692,125 | 31,304,390 | 5,497,997 | 4,021,769 | 6,794,203 | 9,818,096 | 228,693 | 13,182,269 | 150,369,039 | *13,410,962* |
| 20 | Winter | 746,936 | 45,070,549 | 3,184,873 | 16,048,271 | 25,404,411 | 4,240,672 | 2,659,928 | 4,229,696 | 5,835,457 | 117,040 | 5,439,240 | 112,977,070 | *5,556,279* |
| 21 | Summer | 408,059 | 10,670,053 | 749,027 | 2,643,854 | 5,899,979 | 1,257,325 | 1,361,841 | 2,564,508 | 3,982,639 | 111,654 | 7,743,029 | 37,391,968 | *7,854,683* |
| 22 | First Block Therms | | | | | | | | | | | | | |
| 23 | Winter | 255,717 | 30,949,946 | 2,308,077 | 3,732,628 | 8,479,992 | 4,240,672 | 623,753 | 1,741,366 | 5,835,457 | 117,040 | 5,439,240 | 63,724,087 | *5,556,279* |
| 24 | Summer | 230,961 | 6,272,924 | 380,880 | 452,628 | 2,279,752 | 1,257,325 | 436,742 | 1,475,361 | 3,982,639 | 111,654 | 7,743,029 | 24,623,897 | *7,854,683* |
| 25 | Second Block Therms | | | | | | | | | | | | | |
| 26 | Winter | 491,218 | 14,120,603 | 876,795 | 12,315,443 | 16,924,419 | (0) | 2,036,175 | 2,488,330 | 0 | (0) | (0) | 49,252,983 | *(0)* |
| 27 | Summer | 177,098 | 4,397,129 | 368,147 | 2,191,227 | 3,620,227 | (0) | 925,098 | 1,089,146 | (0) | 0 | 0 | 12,768,072 | *0* |
| 28 | | | | | | | | | | | | | | |

**National Grid NH**
**Rate Design**
**Rate Design Calculations**



| Line No. | Description | Non-Heat | Heat | Low Income | Small High Winter Use | Med High Winter Use | Large High Winter Use | Small Low Winter Use | Med Low Winter Use | Large Load Factor <90% | Large Load Factor <110% | Large Load Factor >110% | Total | *Large Load Factor >90%* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Rate Designation | RNSH R-1 | RSH R-3 | RLIAP R-4 | SH G-41 | MH G-42 | LH G-43 | SL G-51 | ML G-52 | LLL90 G-53 | LLL110 G-54 | LLG110 G-63 | | *LLG90 G-54 + G-63* |
| 29 | **Pure Marginal Cost Based Rates** | | | | | | | | | | | | | |
| 30 | Facilities Charge per Month | $25.47 | $37.07 | $37.07 | $72.41 | $409.63 | $1,935.65 | $57.64 | $270.70 | $2,102.74 | $1,442.55 | $2,967.27 | | |
| 31 | | | | | | | | | | | | | | |
| 32 | **Test Year Revenues - No R-4 Discount** | | | | | | | | | | | | | |
| 33 | Current Rate Net Revenues - Total | $695,846 | $21,380,573 | $1,524,390 | $6,534,929 | $7,712,431 | $905,574 | $1,141,550 | $1,097,229 | $954,664 | $17,397 | $385,076 | $42,349,662 | *402,474* |
| 34 | Customer | $412,551 | $7,495,444 | $536,787 | $2,151,804 | $1,218,634 | $152,859 | $403,749 | $249,211 | $137,900 | $3,710 | $57,440 | $12,820,089 | *61,150* |
| 35 | Winter | $181,389 | $11,330,588 | $815,490 | $3,778,846 | $5,247,085 | $662,817 | $481,152 | $584,628 | $615,641 | $9,188 | $184,390 | $23,891,214 | *193,578* |
| 36 | Summer | $101,906 | $2,554,542 | $172,113 | $604,279 | $1,246,712 | $89,899 | $256,649 | $263,390 | $201,123 | $4,500 | $143,246 | $5,638,359 | *147,746* |
| 37 | Target Revenues | 845,445 | 25,977,141 | 1,852,116 | 7,455,449 | 8,485,164 | 1,100,262 | 1,141,550 | 1,147,833 | 1,139,543 | 21,032 | 467,863 | 49,633,399 | *488,895* |
| 38 | % Increase | 21.50% | 21.50% | 21.50% | 14.09% | 10.02% | 21.50% | 0.00% | 4.61% | 19.37% | 20.89% | 21.50% | 17.20% | *21.47%* |
| 39 | | | | | | | | | | | | | | |
| 40 | **Customer Charge Calculation** | | | | | | | | | | | | | |
| 41 | Capped Maximum Customer Charge | $13.82 | $19.76 | $19.76 | $49.28 | $138.72 | $598.78 | $49.62 | $138.58 | $600.00 | $600.00 | $600.00 | | *$600.00* |
| 42 | Marginal Facilities Cost | $25.47 | $37.07 | $37.07 | $72.41 | $409.63 | $1,935.65 | $57.64 | $270.70 | $2,102.74 | $1,442.55 | $2,967.27 | | *$2,874.77* |
| 43 | Trial Customer Charge, Rounded | $13.75 | $19.75 | $19.75 | $50.00 | $140.00 | $600.00 | $50.00 | $140.00 | $600.00 | $600.00 | $600.00 | | *$600.00* |
| 44 | Customer Revenue | $820,924 | $14,983,301 | $1,073,574 | $4,366,485 | $2,459,756 | $306,340 | $813,682 | $503,529 | $275,800 | $7,420 | $114,880 | $25,725,692 | *$122,300* |
| 45 | | | | | | | | | | | | | | |
| 46 | **Seasonal Therm Charges** | | | | | | | | | | | | | |
| 47 | Revenue Required from Therm Rates | $24,521 | $10,993,840 | $778,542 | $3,088,964 | $6,025,406 | $793,922 | $327,868 | $644,304 | $863,743 | $13,612 | $352,983 | $23,907,707 | *$366,595* |
| 48 | Revenues Produced by Current Therm Rates | $283,295 | $13,885,129 | $987,603 | $4,383,126 | $6,493,797 | $752,716 | $737,801 | $848,019 | $816,764 | $13,687 | $327,636 | $29,529,573 | *$341,324* |
| 49 | Percent Increase to Therm Rates Required | -91.34% | -20.82% | -21.17% | -29.53% | -7.21% | 5.47% | -55.56% | -24.02% | 5.75% | -0.55% | 7.74% | -19.04% | *7.40%* |
| 50 | | | | | | | | | | | | | | |
| 51 | **Pro Rata Adjustment to Present Rates** | | | | | | | | | | | | | |
| 52 | Current Winter Head Block Rate | $ 0.02278 | $ 0.22912 | $ 0.22812 | $ 0.22679 | $ 0.24762 | $ 0.16489 | $ 0.11025 | $ 0.12945 | $ 0.11160 | $ 0.07808 | $ 0.03652 | | *$0.0374* |
| 53 | Current WinterTail Block Rate | $ 0.02011 | $ 0.13311 | $ 0.13253 | $ 0.14750 | $ 0.16356 | $ 0.16489 | $ 0.07122 | $ 0.08787 | $ 0.11160 | $ 0.07808 | $ 0.03652 | | *$0.0374* |
| 54 | Current Summer Head Block Rate | $ 0.02278 | $ 0.22912 | $ 0.22812 | $ 0.22679 | $ 0.24762 | $ 0.07545 | $ 0.11025 | $ 0.09519 | $ 0.05341 | $ 0.04007 | $ 0.01990 | | *$0.0202* |
| 55 | Current SummerTail Block Rate | $ 0.02011 | $ 0.13311 | $ 0.13253 | $ 0.14750 | $ 0.16356 | $ 0.07545 | $ 0.07122 | $ 0.05480 | $ 0.05341 | $ 0.04007 | $ 0.01990 | | *$0.0202* |
| 56 | | | | | | | | | | | | | | |

**National Grid NH**
**Rate Design**
**Rate Design Calculations**



| Line No. | Description | Non-Heat | Heat | Low Income | Small High Winter Use | Med High Winter Use | Large High Winter Use | Small Low Winter Use | Med Low Winter Use | Large Load Factor <90% | Large Load Factor <110% | Large Load Factor >110% | Total | *Large Load Factor >90%* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Rate Designation | RNSH R-1 | RSH R-3 | RLIAP R-4 | SH G-41 | MH G-42 | LH G-43 | SL G-51 | ML G-52 | LLL90 G-53 | LLL110 G-54 | LLG110 G-63 | | *LLG90 G-54 + G-63* |
| 57 | **Proposed Rate Design - Ignoring R-4 Discount** | | | | | | | | | | | | | |
| 58 | Customer Charge | $13.75 | $19.75 | $19.75 | $50.00 | $140.00 | $600.00 | $50.00 | $140.00 | $600.00 | $600.00 | $600.00 | | *$600.00* |
| 59 | Winter Volumetric Rates | | | | | | | | | | | | | |
| 60 | Headblock Rate | $0.0228 | $0.2291 | $0.2291 | $0.2268 | $0.2476 | $0.1649 | $0.1103 | $0.1295 | $0.1116 | $0.0781 | $0.0365 | | *$0.0374* |
| 61 | Tailblock Rate | $0.0201 | $0.1331 | $0.1331 | $0.1475 | $0.1636 | $0.1649 | $0.0712 | $0.0879 | $0.1116 | $0.0781 | $0.0365 | | *$0.0374* |
| 62 | Summer Volumetric Rates | | | | | | | | | | | | | |
| 63 | Headblock Rate | $0.0228 | $0.2291 | $0.2291 | $0.2268 | $0.2476 | $0.0754 | $0.1103 | $0.0952 | $0.0534 | $0.0401 | $0.0199 | | *$0.0202* |
| 64 | Tailblock Rate | $0.0201 | $0.1331 | $0.1331 | $0.1475 | $0.1636 | $0.0754 | $0.0712 | $0.0548 | $0.0534 | $0.0401 | $0.0199 | | *$0.0202* |
| 65 | | | | | | | | | | | | | | |
| 66 | **Proposed Revenues - Ignoring R-4 Discount** | | | | | | | | | | | | | |
| 67 | Customer Charge | $820,924 | $14,983,301 | $1,073,674 | $4,366,485 | $2,459,758 | $306,340 | $813,682 | $503,529 | $275,800 | $7,420 | $114,880 | $25,725,692 | *$122,300* |
| 68 | Winter Volumetric Rates | | | | | | | | | | | | | |
| 69 | Headblock Rate | $5,830 | $7,090,633 | $528,780 | $846,605 | $2,099,646 | $699,287 | $68,800 | $225,507 | $651,237 | $9,141 | $198,532 | $12,423,999 | *$207,805* |
| 70 | Tailblock Rate | $9,873 | $1,879,452 | $116,701 | $1,816,528 | $2,768,835 | ($0) | $144,976 | $218,724 | $0 | ($0) | ($0) | $6,955,090 | *($0)* |
| 71 | Summer Volumetric Rates | | | | | | | | | | | | | |
| 72 | Headblock Rate | $5,266 | $1,437,127 | $87,260 | $102,656 | $564,467 | $94,802 | $48,173 | $140,454 | $212,673 | $4,477 | $154,086 | $2,851,441 | *$158,665* |
| 73 | Tailblock Rate | $3,560 | $585,258 | $49,000 | $323,206 | $592,269 | ($0) | $65,867 | $59,685 | ($0) | $0 | $0 | $1,678,845 | *$0* |
| 74 | Total | $845,453 | $25,975,771 | $1,855,316 | $7,455,480 | $8,484,975 | $1,100,429 | $1,141,497 | $1,147,899 | $1,139,710 | $21,038 | $467,499 | $49,635,066 | *$488,769* |
| 75 | Variance from Target (Due to Rounding) | $8 | ($1,370) | $3,200 | $31 | ($190) | $167 | ($53) | $66 | $167 | $6 | ($365) | $1,667 | *($126)* |
| 76 | | | | | | | | | | | | | | |
| 77 | R-4 Discount, % | | | 60% | | | | | | | | | | |
| 78 | **Proposed Rate Design - Including R-4 Discount** | | | | | | | | | | | | | |
| 79 | Customer Charge | $13.75 | $19.75 | $7.90 | $50.00 | $140.00 | $600.00 | $50.00 | $140.00 | $600.00 | $600.00 | $600.00 | | *$600.00* |
| 80 | Winter Volumetric Rates | | | | | | | | | | | | | |
| 81 | Headblock Rate | $0.0228 | $0.2291 | $0.0916 | $0.2268 | $0.2476 | $0.1649 | $0.1103 | $0.1295 | $0.1116 | $0.0781 | $0.0365 | | *$0.0374* |
| 82 | Tailblock Rate | $0.0201 | $0.1331 | $0.0532 | $0.1475 | $0.1636 | $0.1649 | $0.0712 | $0.0879 | $0.1116 | $0.0781 | $0.0365 | | *$0.0374* |
| 83 | Summer Volumetric Rates | | | | | | | | | | | | | |
| 84 | Headblock Rate | $0.0228 | $0.2291 | $0.0916 | $0.2268 | $0.2476 | $0.0754 | $0.1103 | $0.0952 | $0.0534 | $0.0401 | $0.0199 | | *$0.0202* |
| 85 | Tailblock Rate | $0.0201 | $0.1331 | $0.0532 | $0.1475 | $0.1636 | $0.0754 | $0.0712 | $0.0548 | $0.0534 | $0.0401 | $0.0199 | | *$0.0202* |
| 86 | | | | | | | | | | | | | | |
| 87 | **Proposed Revenues - Including R-4 Discount** | | | | | | | | | | | | | |
| 88 | Customer Charge | $820,924 | $14,983,301 | $429,430 | $4,366,485 | $2,459,758 | $306,340 | $813,682 | $503,529 | $275,800 | $7,420 | $114,880 | $25,081,548 | *$122,300* |
| 89 | Winter Volumetric Rates | | | | | | | | | | | | | |
| 90 | Headblock Rate | $5,830 | $7,090,633 | $211,420 | $846,605 | $2,099,646 | $699,287 | $68,800 | $225,507 | $651,237 | $9,141 | $198,532 | $12,106,638 | *$207,805* |
| 91 | Tailblock Rate | $9,873 | $1,879,452 | $46,646 | $1,816,528 | $2,768,835 | ($0) | $144,976 | $218,724 | $0 | ($0) | ($0) | $6,885,034 | *($0)* |
| 92 | Summer Volumetric Rates | | | | | | | | | | | | | |
| 93 | Headblock Rate | $5,266 | $1,437,127 | $34,889 | $102,656 | $564,467 | $94,802 | $48,173 | $140,454 | $212,673 | $4,477 | $154,086 | $2,799,070 | *$158,665* |
| 94 | Tailblock Rate | $3,560 | $585,258 | $19,585 | $323,206 | $592,269 | ($0) | $65,867 | $59,685 | ($0) | $0 | $0 | $1,649,430 | *$0* |
| 95 | Total | $845,453 | $25,975,771 | $741,969 | $7,455,480 | $8,484,975 | $1,100,429 | $1,141,497 | $1,147,899 | $1,139,710 | $21,038 | $467,499 | $48,521,720 | *$488,769* |

**National Grid NH**
**Rate Design Filing**
**Summary of Proposed Rates**



| Line No. | Description | RESIDENTIAL Non-Heat | RESIDENTIAL Heat | RESIDENTIAL Low Income (Prior to | C & I High Winter Use Small High Winter Use | C & I High Winter Use Med High Winter Use | C & I High Winter Use Large High Winter Use | C & I Low Winter Use Small Low Winter Use | C & I Low Winter Use Med Low Winter Use | C & I Low Winter Use Large Load Factor <90% | C & I Low Winter Use Large Load Factor <110% | C & I Low Winter Use Large Load Factor >110% | *Large Load Factor >110%* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | RNSH | RSH | RLIAP | SH | MH | LH | SL | ML | LLL90 | LLL110 | LLG110 | *LLG90* |
| | | R-1 | R-3 | R-4 | G-41 | G-42 | G-43 | G-51 | G-52 | G-53 | G-54 | G-63 | *G-54+G-63* |
| | **Eligibility** | | | | | | | | | | | | |
| 1 | Annual Usage, Therms | N/A | N/A | N/A | <=10,000 | <=100,000 | >100,000 | <=10,000 | <=100,000 | >100,000 | >100,000 | >100,000 | *>100,000* |
| 2 | Summer Usage, % of Annual | N/A | N/A | N/A | <=33% | <=33% | <=33% | >33% | >33% | >33% | >33% | >33% | *>33%* |
| 3 | Load Factor, Avg Use/Dec - Feb Avg Use | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | <90% | <110% | >=110% | *>=90%* |
| 4 | | | | | | | | | | | | | |
| 5 | **Customer Charge, $/Month** | $13.75 | $19.75 | $7.90 | $50.00 | $140.00 | $600.00 | $50.00 | $140.00 | $600.00 | $600.00 | $600.00 | *$600.00* |
| 6 | | | | | | | | | | | | | |
| 7 | **Winter Rate** | | | | | | | | | | | | |
| 8 | Head Block Size | 10 | 100 | 100 | 100 | 1,000 | N/A | 100 | 1,000 | N/A | N/A | N/A | *N/A* |
| 9 | Head Block Rate | $ 0.0228 | $ 0.2291 | $ 0.0916 | $ 0.2268 | $ 0.2476 | $ 0.1649 | $ 0.1103 | $ 0.1295 | $ 0.1116 | $ 0.0781 | $ 0.0365 | *$ 0.0374* |
| 10 | Tail Block Rate | $ 0.0201 | $ 0.1331 | $ 0.0532 | $ 0.1475 | $ 0.1636 | $ 0.1649 | $ 0.0712 | $ 0.0879 | $ 0.1116 | $ 0.0781 | $ 0.0365 | *$ 0.0374* |
| 11 | | | | | | | | | | | | | |
| 12 | **Summer Rate** | | | | | | | | | | | | |
| 13 | Head Block Size | 10 | 20 | 20 | 20 | 400 | N/A | 100 | 1,000 | N/A | N/A | N/A | *N/A* |
| 14 | Head Block Rate | $ 0.0228 | $ 0.2291 | $ 0.0916 | $ 0.2268 | $ 0.2476 | $ 0.0754 | $ 0.1103 | $ 0.0952 | $ 0.0534 | $ 0.0401 | $ 0.0199 | *$ 0.0202* |
| 15 | Tail Block Rate | $ 0.0201 | $ 0.1331 | $ 0.0532 | $ 0.1475 | $ 0.1636 | $ 0.0754 | $ 0.0712 | $ 0.0548 | $ 0.0534 | $ 0.0401 | $ 0.0199 | *$ 0.0202* |

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**National Grid NH**
**Rate Design Filing**
**Total Revenue Comparison**



| Line No. | Description | | Non-Heat | Heat | Low Income (After Discount) | Small High Winter Use | Med High Winter Use | Large High Winter Use | Small Low Winter Use | Med Low Winter Use | Large Load Factor <90% | Large Load Factor <110% | Large Load Factor >110% | Total | Large Load Factor >110% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Rate Designation | | RNSH | RSH | RLIAP | SH | MH | LH | SL | ML | LL190 | LLL110 | LLG110 | | LLG90 |
| | | | R-1 | R-3 | R-4 | G-41 | G-42 | G-43 | G-51 | G-53 | G-53 | G-54 | G-63 | | G-54 + G-63 |
| | **PRESENT RATES** | | | | | | | | | | | | | | |
| 1 | Cost of Gas Clause - Equivalent Dry Therm Rates | (1)(2) | | | | | | | | | | | | | |
| 2 | Winter | | $ 1.1208 | $ 1.1200 | $ 1.1200 | $ 1.1206 | $ 1.1200 | $ 1.1208 | $ 1.1200 | $ 1.1200 | $ 1.1200 | $ 1.1200 | $ 1.1200 | | $ 1.1200 |
| 3 | Summer | | $ 0.9423 | $ 0.9423 | $ 0.9423 | $ 0.9451 | $ 0.9451 | $ 0.9451 | $ 0.9404 | $ 0.0404 | $ 0.9404 | $ 0.9404 | $ 0.9404 | | $ 0.9404 |
| 4 | | | | | | | | | | | | | | | |
| 5 | Local Distribution Adjustment Clause - Dry therms | (1) | | | | | | | | | | | | | |
| 6 | Winter (January, 2008) | | $ 0.0184 | $ 0.0189 | $ 0.0189 | $ 0.0099 | $ 0.0099 | $ 0.0099 | $ 0.0099 | $ 0.0099 | $ 0.0090 | $ 0.0099 | $ 0.0099 | | $ 0.0099 |
| 7 | Summer (October, 2007) | | $ 0.0381 | $ 0.0387 | $ 0.0387 | $ 0.0338 | $ 0.0338 | $ 0.0336 | $ 0.0338 | $ 0.0336 | $ 0.0336 | $ 0.0336 | $ 0.0336 | | $ 0.0336 |
| 8 | | | | | | | | | | | | | | | |
| 9 | Total Present Revenue | | | | | | | | | | | | | | |
| 10 | Present Delivery Revenues | (3) | 695,846 | 21,360,573 | 609,756 | 6,534,929 | 7,712,431 | 905,574 | 1,141,550 | 1,097,229 | 954,664 | 17,397 | 385,076 | 41,435,027 | 402,474 |
| 11 | Delivery Adjustment (LDAC) | | 28,291 | 1,264,764 | 89,181 | 247,711 | 449,743 | 84,229 | 72,091 | 128,041 | 191,588 | 4,910 | 314,014 | 2,875,564 | 318,925 |
| 12 | Supply Charges (COGC) | (4) | 1,221,530 | 60,560,448 | 4,274,776 | 20,482,399 | 34,044,253 | 5,940,395 | 4,259,795 | 7,148,922 | 10,280,986 | 236,083 | 13,373,493 | 161,823,080 | 13,609,577 |
| 13 | Total | | 1,946,667 | 83,205,785 | 4,973,714 | 27,265,040 | 42,206,428 | 6,930,198 | 5,473,436 | 8,374,193 | 11,427,237 | 258,391 | 14,072,584 | 206,133,672 | 14,330,975 |
| 14 | | | | | | | | | | | | | | | |
| 15 | | | | | | | | | | | | | | | |
| 16 | | | | | | | | | | | | | | | |
| 17 | **PROPOSED RATES** | | | | | | | | | | | | | | |
| 18 | Proposed Cost of Gas Clause - Equivalend Dry Therm Rates | | | | | | | | | | | | | | |
| 19 | Winter | (2) | $ 1.1337 | $ 1.1337 | $ 1.1337 | $ 1.1337 | $ 1.1337 | $ 1.1337 | $ 1.1336 | $ 1.1336 | $ 1.1336 | $ 1.1336 | $ 1.1336 | | $ 1.1336 |
| 20 | Summer | | $ 0.9556 | $ 0.9556 | $ 0.9556 | $ 0.9583 | $ 0.9583 | $ 0.9583 | $ 0.9537 | $ 0.9537 | $ 0.9537 | $ 0.9537 | $ 0.9537 | | $ 0.9537 |
| 21 | | | | | | | | | | | | | | | |
| 22 | Local Distribution Adjustment Clause - Dry therms | (1) | | | | | | | | | | | | | |
| 23 | Winter (January, 2008) | | $ 0.0184 | $ 0.0189 | $ 0.0189 | $ 0.0099 | $ 0.0099 | $ 0.0099 | $ 0.0090 | $ 0.0099 | $ 0.0099 | $ 0.0099 | $ 0.0099 | | $ 0.0099 |
| 24 | Summer (October, 2007) | | $ 0.0381 | $ 0.0387 | $ 0.0387 | $ 0.0336 | $ 0.0336 | $ 0.0336 | $ 0.0336 | $ 0.0336 | $ 0.0336 | $ 0.0330 | $ 0.0336 | | $ 0.0336 |
| 25 | | | | | | | | | | | | | | | |
| 26 | Total Proposed Revenue | | | | | | | | | | | | | | |
| 27 | Proposeed Delivery Revenues | (5) | 845,453 | 25,975,771 | 741,969 | 7,455,480 | 8,484,975 | 1,100,429 | 1,141,497 | 1,147,899 | 1,139,710 | 21,038 | 467,499 | 48,521,720 | 488,769 |
| 28 | Delivery Adjustment (LDAC) | | 29,291 | 1,264,764 | 89,181 | 247,711 | 449,743 | 84,229 | 72,091 | 128,041 | 191,588 | 4,910 | 314,014 | 2,875,564 | 318,925 |
| 29 | Supply Charges (COGC) | (4) | 1,236,742 | 81,292,784 | 4,326,460 | 20,727,530 | 34,454,931 | 6,012,545 | 4,314,082 | 7,240,554 | 10,413,317 | 239,160 | 13,550,449 | 163,808,554 | 13,789,609 |
| 30 | Total | | $ 2,111,486 | $ 88,533,319 | $ 5,157,611 | $ 28,430,722 | $ 43,389,649 | $ 7,197,203 | $ 5,527,670 | $ 8,516,494 | $ 11,744,615 | $ 265,108 | $ 14,331,962 | $ 215,205,838 | $ 14,597,303 |
| 31 | | | | | | | | | | | | | | | |
| 32 | Increase, % | | 8.47% | 6.40% | 3.70% | 4.28% | 2.80% | 3.85% | 0.99% | 1.70% | 2.78% | 2.60% | 1.84% | 4.40% | 1.86% |

NOTES
1 All rates reflect an adjustment to restate CGC and LDAC rates in terms of dry therms
2 Indirect Gas cost in Current COG represent Bad Debt & Working Capital Factors from DG 08-083 and Production & Storage and Miscellaneous Gas costs from DG 06-121.
3 Source: Attachment GLG-RD-4-2 Page 1.
4 Imputes gas supply charges for all transportation customers
5 Source: Attachment GLG-RD-4-3 Page 5.

**National Grid NH**
**Rate Design Filing**
**Revenue Proof**



| Line No. | Description | Residential: Non-Heat | Residential: Heat | Residential: Low Income (Prior to Discount) | C&I High Winter Use: Small High Winter Use | C&I High Winter Use: Med High Winter Use | C&I High Winter Use: Large High Winter Use | C&I Low Winter Use: Small Low Winter Use | C&I Low Winter Use: Med Low Winter Use | C&I Low Winter Use: Large Load Factor <90% | C&I Low Winter Use: Large Load Factor <110% | C&I Low Winter Use: Large Load Factor >110% | Total | Combined: Large Load Factor >90% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Rate Designation** | RNSH | RSH | RLIAP | SH | MH | LH | SL | ML | LLL90 | LLL110 | LLG110 | | LLG90 |
| | | R-1 | R-3 | R-4 | G-41 | G-42 | G-43 | G-51 | G-52 | G-53 | G-54 | G-63 | | G-54 + G-63 |
| 1 | | | | | | | | | | | | | | |
| 2 | **Proposed Rates (Dry) - No R-4 Discount** | | | | | | | | | | | | | |
| 3 | Winter Head Block Size | 10 | 100 | 100 | 100 | 1,000 | 0 | 100 | 1,000 | 0 | 0 | 0 | | - |
| 4 | Summer Head Block Size | 10 | 20 | 20 | 20 | 400 | 0 | 100 | 1,000 | 0 | 0 | 0 | | - |
| 5 | Proposed Customer Charge | $13.75 | $19.75 | $19.75 | $50.00 | $140.00 | $600.00 | $50.00 | $140.00 | $600.00 | $600.00 | $600.00 | | $600.00 |
| 6 | Proposed Winter Head Block Rate | $0.02280 | $0.22910 | $0.22910 | $0.22680 | $0.24760 | $0.16490 | $0.11030 | $0.12950 | $0.11160 | $0.07810 | $0.03650 | | $0.03810 |
| 7 | Proposed WinterTail Block Rate | $0.02010 | $0.13310 | $0.13310 | $0.14750 | $0.16360 | $0.16490 | $0.07120 | $0.08790 | $0.11160 | $0.07810 | $0.03650 | | $0.03810 |
| 8 | Proposed Summer Head Block Rate | $0.02280 | $0.22910 | $0.22910 | $0.22680 | $0.24760 | $0.07540 | $0.11030 | $0.09520 | $0.05340 | $0.04010 | $0.01990 | | $0.01970 |
| 9 | Proposed SummerTail Block Rate | $0.02010 | $0.13310 | $0.13310 | $0.14750 | $0.16360 | $0.07540 | $0.07120 | $0.05480 | $0.05340 | $0.04010 | $0.01990 | | $0.01970 |
| 10 | | | | | | | | | | | | | | |
| 11 | **Total Sales and Transportation (Dry)** | | | | | | | | | | | | | |
| 12 | **Test Year Normal (After Weather Normalization)** | | | | | | | | | | | | | |
| 13 | Winter Bills | 29,521 | 379,317 | 26,528 | 43,909 | 8,727 | 268 | 8,107 | 1,792 | 229 | 6 | 98 | 498,500 | 103 |
| 14 | Summer Bills | 30,183 | 379,332 | 27,830 | 43,421 | 8,843 | 243 | 8,166 | 1,805 | 231 | 7 | 94 | 500,154 | 100 |
| 15 | Winter Sales, Therms | 746,936 | 45,070,549 | 3,184,873 | 16,048,271 | 25,404,411 | 4,240,672 | 2,659,928 | 4,229,696 | 5,835,457 | 117,040 | 5,439,240 | 112,977,070 | 5,556,279 |
| 16 | Summer Sales, Therms | 408,059 | 10,670,053 | 749,027 | 2,643,854 | 5,899,979 | 1,257,325 | 1,361,841 | 2,564,508 | 3,982,639 | 111,654 | 7,743,029 | 37,391,968 | 7,854,683 |
| 17 | Total Annual Sales | 1,154,994 | 55,740,602 | 3,933,900 | 18,692,125 | 31,304,390 | 5,497,997 | 4,021,769 | 6,794,203 | 9,818,096 | 228,693 | 13,182,269 | 150,369,039 | 13,410,962 |
| 18 | Winter Head Block Therms | 255,717 | 30,949,946 | 2,308,077 | 3,732,828 | 8,479,992 | - | 623,753 | 1,741,366 | - | - | - | 48,091,679 | 0 |
| 19 | Summer Head Block Therms | 230,961 | 6,272,924 | 380,880 | 452,628 | 2,279,752 | - | 436,742 | 1,475,351 | - | - | - | 11,529,249 | 0 |
| 20 | | | | | | | | | | | | | | |
| 21 | | | | | | | | | | | | | | |
| 22 | **Billed Revenue** | | | | | | | | | | | | | |
| 23 | Winter Customer Charge Revenue | 405,913 | 7,491,502 | 523,932 | 2,195,438 | 1,221,715 | 160,520 | 405,367 | 250,819 | 137,300 | 3,440 | 58,640 | 12,854,586 | 62,080 |
| 24 | Summer Customer Charge Revenue | 415,010 | 7,491,800 | 549,642 | 2,171,047 | 1,238,043 | 145,820 | 408,315 | 252,709 | 138,500 | 3,980 | 56,240 | 12,871,106 | 60,220 |
| 25 | Subtotal Customer Charge Revenue | 820,924 | 14,983,301 | 1,073,574 | 4,366,485 | 2,459,758 | 306,340 | 813,682 | 503,529 | 275,800 | 7,420 | 114,880 | 25,725,692 | 122,300 |
| 26 | | | | | | | | | | | | | | |
| 27 | Winter Head Block Revenue | 5,830 | 7,090,633 | 528,780 | 846,605 | 2,099,646 | - | 68,800 | 225,507 | - | - | - | 10,865,802 | 0 |
| 28 | Tail Block Winter Therm Revenue | 9,873 | 1,879,452 | 116,701 | 1,816,528 | 2,768,835 | 699,287 | 144,976 | 218,724 | 651,237 | 9,141 | 198,532 | 8,513,287 | 207,673 |
| 29 | Subtotal Winter Therm Revenue | 15,704 | 8,970,085 | 645,482 | 2,663,133 | 4,868,481 | 699,287 | 213,776 | 444,231 | 651,237 | 9,141 | 198,532 | 19,379,088 | 207,673 |
| 30 | | | | | | | | | | | | | | |
| 31 | Summer Head Block Revenue | 5,266 | 1,437,127 | 87,260 | 102,656 | 564,467 | - | 48,173 | 140,454 | - | - | - | 2,385,402 | 0 |
| 32 | Tail Block Summer Therm Revenue | 3,560 | 585,258 | 49,000 | 323,206 | 592,269 | 94,802 | 65,867 | 59,685 | 212,673 | 4,477 | 154,086 | 2,144,884 | 158,564 |
| 33 | Subtotal Summer Therm Revenues | 8,826 | 2,022,385 | 136,260 | 425,862 | 1,156,736 | 94,802 | 114,040 | 200,140 | 212,673 | 4,477 | 154,086 | 4,530,286 | 158,564 |
| 34 | | | | | | | | | | | | | | |
| 35 | Total Annual Revenues | 845,453 | 25,975,771 | 1,855,316 | 7,455,480 | 8,484,975 | 1,100,429 | 1,141,497 | 1,147,699 | 1,139,710 | 21,038 | 467,499 | 49,635,066 | 488,537 |
| 36 | | | | | | | | | | | | | | |
| 37 | | | | | | | | | | | | | | |
| 38 | **Target Revenues** | | | | | | | | | | | | | |
| 39 | Total Target Base Revenue | 845,445 | 25,977,141 | 1,852,116 | 7,455,449 | 8,485,164 | 1,100,262 | 1,141,550 | 1,147,833 | 1,139,543 | 21,032 | 467,863 | 49,633,399 | 488,895 |
| 40 | | | | | | | | | | | | | | |
| 41 | | | | | | | | | | | | | | |
| 42 | **Variance** | | | | | | | | | | | | | |
| 43 | Variance, $s | 8 | (1,370) | 3,200 | 31 | (190) | 167 | (53) | 66 | 167 | 6 | (365) | 1,667 | (358) |
| 44 | Variance, % | 0.0% | 0.0% | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | -0.1% | 0.0% | -0.1% |

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Winter Season
Residential Non-Heating
Rate R-1

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $6.91 | NA | $13.75 | NA | $6.84 | 98.99% | $6.91 | NA | $13.75 | NA | $6.84 | 98.99% |
| 2 | 7.44 | 3.718 | 13.80 | 6.898 | 6.36 | 85.52% | 9.71 | 4.857 | 16.10 | 8.050 | 6.39 | 65.73% |
| 4 | 7.96 | 1.991 | 13.84 | 3.460 | 5.88 | 73.83% | 12.52 | 3.130 | 18.45 | 4.612 | 5.93 | 47.38% |
| 6 | 8.49 | 1.415 | 13.89 | 2.314 | 5.40 | 63.59% | 15.32 | 2.554 | 20.80 | 3.467 | 5.48 | 35.74% |
| 8 | 9.01 | 1.127 | 13.93 | 1.742 | 4.92 | 54.55% | 18.13 | 2.266 | 23.15 | 2.894 | 5.02 | 27.71% |
| 10 | 9.54 | 0.954 | 13.98 | 1.398 | 4.44 | 46.50% | 20.93 | 2.093 | 25.50 | 2.550 | 4.57 | 21.82% |
| 15 | 10.70 | 0.714 | 14.08 | 0.939 | 3.38 | 31.54% | 27.79 | 1.853 | 31.36 | 2.091 | 3.57 | 12.86% |
| 20 | 11.86 | 0.593 | 14.18 | 0.709 | 2.32 | 19.51% | 34.64 | 1.732 | 37.22 | 1.861 | 2.58 | 7.44% |
| 25 | 13.03 | 0.521 | 14.28 | 0.571 | 1.25 | 9.63% | 41.50 | 1.660 | 43.08 | 1.723 | 1.58 | 3.81% |
| 30 | 14.19 | 0.473 | 14.38 | 0.479 | 0.19 | 1.36% | 48.36 | 1.612 | 48.94 | 1.631 | 0.59 | 1.21% |
| 35 | 15.35 | 0.439 | 14.48 | 0.414 | (0.87) | -5.66% | 55.21 | 1.578 | 54.80 | 1.566 | (0.41) | -0.74% |
| 40 | 16.51 | 0.413 | 14.58 | 0.365 | (1.93) | -11.68% | 62.07 | 1.552 | 60.67 | 1.517 | (1.41) | -2.26% |
| 45 | 17.67 | 0.393 | 14.68 | 0.326 | (2.99) | -16.92% | 68.93 | 1.532 | 66.53 | 1.478 | (2.40) | -3.48% |
| 50 | 18.83 | 0.377 | 14.78 | 0.296 | (4.05) | -21.51% | 75.78 | 1.516 | 72.39 | 1.448 | (3.40) | -4.48% |
| 60 | 21.16 | 0.353 | 14.98 | 0.250 | (6.17) | -29.18% | 89.50 | 1.492 | 84.11 | 1.402 | (5.39) | -6.02% |
| 70 | 23.48 | 0.335 | 15.18 | 0.217 | (8.30) | -35.33% | 103.21 | 1.474 | 95.83 | 1.369 | (7.38) | -7.15% |
| 80 | 25.80 | 0.323 | 15.39 | 0.192 | (10.42) | -40.37% | 116.92 | 1.462 | 107.55 | 1.344 | (9.37) | -8.01% |
| 90 | 28.13 | 0.313 | 15.59 | 0.173 | (12.54) | -44.58% | 130.64 | 1.452 | 119.28 | 1.325 | (11.36) | -8.70% |
| 100 | 30.45 | 0.304 | 15.79 | 0.158 | (14.66) | -48.15% | 144.35 | 1.443 | 131.00 | 1.310 | (13.35) | -9.25% |
| 200 | 53.68 | 0.268 | 17.80 | 0.089 | (35.88) | -66.84% | 281.46 | 1.407 | 248.22 | 1.241 | (33.26) | -11.82% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 8 | 9.01 | 1.127 | 13.93 | 1.742 | 4.92 | 54.55% | 18.13 | 2.266 | 23.15 | 2.894 | 5.02 | 27.71% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 15 | 10.70 | 0.714 | 14.08 | 0.939 | 3.38 | 31.54% | 27.79 | 1.853 | 31.36 | 2.091 | 3.57 | 12.86% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 25 | 13.03 | 0.521 | 14.28 | 0.571 | 1.25 | 9.63% | 41.50 | 1.660 | 43.08 | 1.723 | 1.58 | 3.81% |

Equivalent DRY Therm Present Rate R-1

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $6.91 | /Customer |
| First | 10 | $0.2831 | /therm |
| Over | 10 | $0.2323 | /therm |
| TOTAL CGC & LDAC | | $1.1390 | /therm |
| CGC | | $1.1206 | |
| LDAC | | $0.0184 | |

Proposed Rate R-1

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $13.75 | /Customer |
| First | 10 | $0.0228 | /therm |
| Over | 10 | $0.0201 | /therm |
| TOTAL CGC & LDAC | | $1.1521 | /therm |
| CGC | | $1.1337 | /therm |
| LDAC | | $0.0184 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Summer Season
Residential Non-Heating
Rate R-1

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $6.91 | NA | $13.75 | NA | $6.84 | 98.99% | $6.91 | NA | $13.75 | NA | $6.84 | 98.99% |
| 2 | 7.44 | 3.718 | 13.80 | 6.898 | 6.36 | 85.52% | 9.40 | 4.699 | 15.78 | 7.892 | 6.39 | 67.96% |
| 4 | 7.96 | 1.991 | 13.84 | 3.460 | 5.88 | 73.83% | 11.88 | 2.971 | 17.82 | 4.454 | 5.93 | 49.92% |
| 6 | 8.49 | 1.415 | 13.89 | 2.314 | 5.40 | 63.59% | 14.37 | 2.395 | 19.85 | 3.308 | 5.48 | 38.12% |
| 8 | 9.01 | 1.127 | 13.93 | 1.742 | 4.92 | 54.55% | 16.86 | 2.107 | 21.88 | 2.735 | 5.02 | 29.80% |
| 10 | 9.54 | 0.954 | 13.98 | 1.398 | 4.44 | 46.50% | 19.35 | 1.935 | 23.92 | 2.392 | 4.57 | 23.62% |
| 15 | 10.70 | 0.714 | 14.08 | 0.939 | 3.38 | 31.54% | 25.41 | 1.694 | 28.98 | 1.932 | 3.58 | 14.07% |
| 20 | 11.86 | 0.593 | 14.18 | 0.709 | 2.32 | 19.51% | 31.47 | 1.574 | 34.05 | 1.703 | 2.58 | 8.20% |
| 25 | 13.03 | 0.521 | 14.28 | 0.571 | 1.25 | 9.63% | 37.54 | 1.501 | 39.12 | 1.565 | 1.59 | 4.23% |
| 30 | 14.19 | 0.473 | 14.38 | 0.479 | 0.19 | 1.36% | 43.60 | 1.453 | 44.19 | 1.473 | 0.59 | 1.36% |
| 35 | 15.35 | 0.439 | 14.48 | 0.414 | (0.87) | -5.66% | 49.66 | 1.419 | 49.26 | 1.407 | (0.40) | -0.81% |
| 40 | 16.51 | 0.413 | 14.58 | 0.365 | (1.93) | -11.68% | 55.73 | 1.393 | 54.33 | 1.358 | (1.40) | -2.51% |
| 45 | 17.67 | 0.393 | 14.68 | 0.326 | (2.99) | -16.92% | 61.79 | 1.373 | 59.40 | 1.320 | (2.39) | -3.87% |
| 50 | 18.83 | 0.377 | 14.78 | 0.296 | (4.05) | -21.51% | 67.85 | 1.357 | 64.47 | 1.289 | (3.39) | -4.99% |
| 60 | 21.16 | 0.353 | 14.98 | 0.250 | (6.17) | -29.18% | 79.98 | 1.333 | 74.61 | 1.243 | (5.38) | -6.72% |
| 70 | 23.48 | 0.335 | 15.18 | 0.217 | (8.30) | -35.33% | 92.11 | 1.316 | 84.74 | 1.211 | (7.36) | -8.00% |
| 80 | 25.80 | 0.323 | 15.39 | 0.192 | (10.42) | -40.37% | 104.23 | 1.303 | 94.88 | 1.186 | (9.35) | -8.97% |
| 90 | 28.13 | 0.313 | 15.59 | 0.173 | (12.54) | -44.58% | 116.36 | 1.293 | 105.02 | 1.167 | (11.34) | -9.75% |
| 100 | 30.45 | 0.304 | 15.79 | 0.158 | (14.66) | -48.15% | 128.49 | 1.285 | 115.16 | 1.152 | (13.33) | -10.38% |
| 200 | 53.68 | 0.268 | 17.80 | 0.089 | (35.88) | -66.84% | 249.76 | 1.249 | 216.54 | 1.083 | (33.22) | -13.30% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 5 | 8.23 | 1.645 | 13.86 | 2.773 | 5.64 | 68.55% | 13.13 | 2.626 | 18.83 | 3.767 | 5.71 | 43.46% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 11 | 9.77 | 0.888 | 14.00 | 1.273 | 4.22 | 43.23% | 20.55 | 1.869 | 24.93 | 2.266 | 4.37 | 21.26% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 20 | 11.86 | 0.593 | 14.18 | 0.709 | 2.32 | 19.51% | 31.47 | 1.574 | 34.05 | 1.703 | 2.58 | 8.20% |

Equivalent DRY Therm Present Rate R-1

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $6.91 | /Customer |
| First | 10 | $0.2631 | /therm |
| Over | 10 | $0.2323 | /therm |
| TOTAL CGC & LDAC | | $0.9804 | /therm |
| CGC | | $0.9423 | |
| LDAC | | $0.0381 | |

Proposed Rate R-1

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $13.75 | /Customer |
| First | 10 | $0.0228 | /therm |
| Over | 10 | $0.0201 | /therm |
| TOTAL CGC & LDAC | | $0.9937 | /therm |
| CGC | | $0.9556 | /therm |
| LDAC | | $0.0381 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Winter Season
Residential Heating
Rate R-3

| | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sales therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $9.88 | NA | $19.75 | NA | $9.87 | 99.90% | $9.88 | NA | $19.75 | NA | $9.87 | 99.90% |
| 10 | 12.77 | 1.277 | 22.04 | 2.204 | 9.27 | 72.55% | 24.17 | 2.417 | 33.57 | 3.357 | 9.40 | 38.88% |
| 25 | 17.12 | 0.685 | 25.48 | 1.019 | 8.36 | 48.86% | 45.60 | 1.824 | 54.29 | 2.172 | 8.69 | 19.06% |
| 50 | 24.35 | 0.487 | 31.21 | 0.624 | 6.86 | 28.15% | 81.33 | 1.627 | 88.84 | 1.777 | 7.51 | 9.23% |
| 75 | 31.59 | 0.421 | 36.93 | 0.492 | 5.35 | 16.93% | 117.05 | 1.561 | 123.38 | 1.645 | 6.33 | 5.41% |
| 100 | 38.82 | 0.388 | 42.66 | 0.427 | 3.84 | 9.89% | 152.77 | 1.528 | 157.92 | 1.579 | 5.15 | 3.37% |
| 125 | 43.02 | 0.344 | 45.99 | 0.368 | 2.97 | 6.89% | 185.46 | 1.484 | 190.06 | 1.521 | 4.60 | 2.48% |
| 150 | 47.23 | 0.315 | 49.32 | 0.329 | 2.09 | 4.43% | 218.16 | 1.454 | 222.21 | 1.481 | 4.06 | 1.86% |
| 175 | 51.43 | 0.294 | 52.64 | 0.301 | 1.22 | 2.36% | 250.84 | 1.433 | 254.35 | 1.453 | 3.51 | 1.40% |
| 200 | 55.63 | 0.278 | 55.97 | 0.280 | 0.34 | 0.61% | 283.53 | 1.418 | 286.49 | 1.432 | 2.96 | 1.04% |
| 225 | 59.83 | 0.266 | 59.30 | 0.264 | (0.54) | -0.89% | 316.22 | 1.405 | 318.63 | 1.416 | 2.41 | 0.76% |
| 250 | 64.04 | 0.256 | 62.63 | 0.251 | (1.41) | -2.20% | 348.91 | 1.395 | 350.78 | 1.403 | 1.87 | 0.53% |
| 275 | 68.24 | 0.248 | 65.95 | 0.240 | (2.29) | -3.35% | 381.60 | 1.388 | 382.92 | 1.392 | 1.32 | 0.35% |
| 300 | 72.44 | 0.241 | 69.28 | 0.231 | (3.16) | -4.36% | 414.29 | 1.381 | 415.06 | 1.384 | 0.77 | 0.19% |
| 350 | 80.85 | 0.231 | 75.94 | 0.217 | (4.91) | -6.07% | 479.67 | 1.370 | 479.35 | 1.370 | (0.32) | -0.07% |
| 400 | 89.25 | 0.223 | 82.59 | 0.206 | (6.66) | -7.46% | 545.05 | 1.363 | 543.63 | 1.359 | (1.42) | -0.26% |
| 450 | 97.66 | 0.217 | 89.25 | 0.198 | (8.41) | -8.61% | 610.43 | 1.357 | 607.92 | 1.351 | (2.51) | -0.41% |
| 500 | 106.06 | 0.212 | 95.90 | 0.192 | (10.16) | -9.58% | 675.81 | 1.352 | 672.20 | 1.344 | (3.61) | -0.53% |
| 750 | 148.09 | 0.197 | 129.18 | 0.172 | (18.91) | -12.77% | 1,002.71 | 1.337 | 993.63 | 1.325 | (9.09) | -0.91% |
| 1,000 | 190.11 | 0.190 | 162.45 | 0.162 | (27.66) | -14.55% | 1,329.61 | 1.330 | 1,315.05 | 1.315 | (14.56) | -1.10% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 55 | 25.80 | 0.469 | 32.35 | 0.588 | 6.55 | 25.40% | 88.47 | 1.609 | 95.74 | 1.741 | 7.27 | 8.22% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 100 | 38.82 | 0.388 | 42.66 | 0.427 | 3.84 | 9.89% | 152.77 | 1.528 | 157.92 | 1.579 | 5.15 | 3.37% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 150 | 47.23 | 0.315 | 49.32 | 0.329 | 2.09 | 4.43% | 218.15 | 1.454 | 222.21 | 1.481 | 4.06 | 1.86% |

Equivalent DRY Therm Present Rate R-3

| | Block therm | Rate |
|---|---|---|
| Customer Charge | - | $9.88 /Customer |
| First | 100 | $0.2894 /therm |
| Over | 100 | $0.1681 /therm |
| TOTAL CGC & LDAC | | $1.1395 /therm |
| CGC | | $1.1206 |
| LDAC | | $0.0189 |

Proposed Rate R-3

| | Block therm | Rate |
|---|---|---|
| Customer Charge | - | $19.75 /Customer |
| First | 100 | $0.2291 /therm |
| Over | 100 | $0.1331 /therm |
| TOTAL CGC & LDAC | | $1.1526 /therm |
| CGC | | $1.1337 /therm |
| LDAC | | $0.0189 /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Summer Season
Residential Heating
Rate R-3

| | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sales therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $9.88 | NA | $19.75 | NA | $9.87 | 99.90% | $9.88 | NA | $19.75 | NA | $9.87 | 99.90% |
| 10 | 12.77 | 1.277 | 22.04 | 2.204 | 9.27 | 72.55% | 22.58 | 2.258 | 31.98 | 3.198 | 9.40 | 41.62% |
| 25 | 16.51 | 0.660 | 25.00 | 1.000 | 8.49 | 51.42% | 41.03 | 1.641 | 49.86 | 1.994 | 8.82 | 21.50% |
| 50 | 20.71 | 0.414 | 28.33 | 0.567 | 7.61 | 36.76% | 69.76 | 1.395 | 78.04 | 1.561 | 8.28 | 11.87% |
| 75 | 24.91 | 0.332 | 31.65 | 0.422 | 6.74 | 27.05% | 98.49 | 1.313 | 106.23 | 1.416 | 7.74 | 7.86% |
| 100 | 29.12 | 0.291 | 34.98 | 0.350 | 5.86 | 20.14% | 127.22 | 1.272 | 134.41 | 1.344 | 7.19 | 5.65% |
| 125 | 33.32 | 0.267 | 38.31 | 0.306 | 4.99 | 14.97% | 155.94 | 1.248 | 162.60 | 1.301 | 6.65 | 4.27% |
| 150 | 37.52 | 0.250 | 41.64 | 0.278 | 4.11 | 10.96% | 184.67 | 1.231 | 190.78 | 1.272 | 6.11 | 3.31% |
| 175 | 41.72 | 0.238 | 44.96 | 0.257 | 3.24 | 7.76% | 213.40 | 1.219 | 218.97 | 1.251 | 5.57 | 2.61% |
| 200 | 45.93 | 0.230 | 48.29 | 0.241 | 2.36 | 5.15% | 242.13 | 1.211 | 247.15 | 1.236 | 5.02 | 2.07% |
| 225 | 50.13 | 0.223 | 51.62 | 0.229 | 1.49 | 2.97% | 270.85 | 1.204 | 275.34 | 1.224 | 4.48 | 1.65% |
| 250 | 54.33 | 0.217 | 54.95 | 0.220 | 0.61 | 1.13% | 299.58 | 1.198 | 303.52 | 1.214 | 3.94 | 1.31% |
| 275 | 58.53 | 0.213 | 58.27 | 0.212 | (0.26) | -0.45% | 328.31 | 1.194 | 331.71 | 1.206 | 3.40 | 1.03% |
| 300 | 62.74 | 0.209 | 61.60 | 0.205 | (1.14) | -1.81% | 357.04 | 1.190 | 359.89 | 1.200 | 2.85 | 0.80% |
| 350 | 71.14 | 0.203 | 68.26 | 0.195 | (2.89) | -4.05% | 414.49 | 1.184 | 416.26 | 1.189 | 1.77 | 0.43% |
| 400 | 79.55 | 0.199 | 74.91 | 0.187 | (4.64) | -5.83% | 471.95 | 1.180 | 472.63 | 1.182 | 0.68 | 0.14% |
| 450 | 87.95 | 0.195 | 81.57 | 0.181 | (6.39) | -7.26% | 529.40 | 1.176 | 529.00 | 1.176 | (0.40) | -0.08% |
| 500 | 96.36 | 0.193 | 88.22 | 0.176 | (8.14) | -8.44% | 586.86 | 1.174 | 585.37 | 1.171 | (1.49) | -0.25% |
| 750 | 138.38 | 0.185 | 121.50 | 0.162 | (16.89) | -12.20% | 874.13 | 1.166 | 867.22 | 1.156 | (6.91) | -0.79% |
| 1,000 | 180.41 | 0.180 | 154.77 | 0.155 | (25.64) | -14.21% | 1,161.41 | 1.161 | 1,149.07 | 1.149 | (12.34) | -1.06% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 13 | 13.64 | 1.049 | 22.73 | 1.748 | 9.09 | 66.60% | 26.40 | 2.030 | 35.65 | 2.743 | 9.26 | 35.08% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 20 | 15.67 | 0.783 | 24.33 | 1.217 | 8.66 | 55.30% | 35.29 | 1.764 | 44.22 | 2.211 | 8.93 | 25.31% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 35 | 18.19 | 0.520 | 26.33 | 0.752 | 8.14 | 44.75% | 52.52 | 1.501 | 61.13 | 1.747 | 8.60 | 16.38% |

| Equivalent DRY Therm Present Rate | Block therm | R-3 Rate | |
|---|---|---|---|
| Customer Charge | - | $9.88 | /Customer |
| First | 20 | $0.2094 | /therm |
| Over | 20 | $0.1681 | /therm |
| TOTAL CGC & LDAC | | $0.9810 | /therm |
| CGC | | $0.9423 | |
| LDAC | | $0.0387 | |

| Proposed Rate | Block therm | R-3 Rate | |
|---|---|---|---|
| Customer Charge | - | $19.75 | /Customer |
| First | 20 | $0.2291 | /therm |
| Over | 20 | $0.1331 | /therm |
| TOTAL CGC & LDAC | | $0.9943 | /therm |
| CGC | | $0.9556 | /therm |
| LDAC | | $0.0387 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Winter Season
Low Income Residential Heating
Rate R-4

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Base | Revenues | Base | Revenues | Revenues Base | Percent Base | | Revenues | | Revenues | Revenues | Percent |
| therm | Rate | Per therm | Rate | Per therm | Rate | Rate | Rate | Per therm | Rate | Per therm | Rate | Rate |
| 0 | $3.95 | NA | $7.90 | NA | $3.95 | 100.00% | $3.95 | NA | $7.90 | NA | $3.95 | 100.00% |
| 10 | 5.11 | 0.511 | 8.82 | 0.882 | 3.71 | 72.59% | 16.50 | 1.650 | 20.34 | 2.034 | 3.84 | 23.26% |
| 25 | 6.85 | 0.274 | 10.19 | 0.408 | 3.35 | 48.87% | 35.33 | 1.413 | 39.01 | 1.560 | 3.67 | 10.39% |
| 50 | 9.74 | 0.195 | 12.48 | 0.250 | 2.74 | 28.13% | 66.72 | 1.334 | 70.11 | 1.402 | 3.40 | 5.09% |
| 75 | 12.64 | 0.168 | 14.77 | 0.197 | 2.14 | 16.90% | 98.10 | 1.308 | 101.22 | 1.350 | 3.12 | 3.18% |
| 100 | 15.53 | 0.155 | 17.06 | 0.171 | 1.53 | 9.85% | 129.48 | 1.295 | 132.32 | 1.323 | 2.84 | 2.19% |
| 125 | 17.21 | 0.138 | 18.39 | 0.147 | 1.18 | 6.86% | 159.65 | 1.277 | 162.47 | 1.300 | 2.82 | 1.76% |
| 150 | 18.89 | 0.126 | 19.72 | 0.131 | 0.83 | 4.39% | 189.82 | 1.265 | 192.61 | 1.284 | 2.79 | 1.47% |
| 175 | 20.57 | 0.118 | 21.05 | 0.120 | 0.48 | 2.33% | 219.98 | 1.257 | 222.76 | 1.273 | 2.77 | 1.26% |
| 200 | 22.25 | 0.111 | 22.38 | 0.112 | 0.13 | 0.56% | 250.15 | 1.251 | 252.90 | 1.265 | 2.75 | 1.10% |
| 225 | 23.93 | 0.106 | 23.71 | 0.105 | (0.22) | -0.92% | 280.32 | 1.246 | 283.05 | 1.258 | 2.73 | 0.97% |
| 250 | 25.61 | 0.102 | 25.04 | 0.100 | (0.57) | -2.23% | 310.49 | 1.242 | 313.19 | 1.253 | 2.70 | 0.87% |
| 275 | 27.29 | 0.099 | 26.37 | 0.096 | (0.92) | -3.37% | 340.65 | 1.239 | 343.34 | 1.248 | 2.68 | 0.79% |
| 300 | 28.97 | 0.097 | 27.70 | 0.092 | (1.27) | -4.38% | 370.82 | 1.236 | 373.48 | 1.245 | 2.66 | 0.72% |
| 350 | 32.33 | 0.092 | 30.36 | 0.087 | (1.97) | -6.09% | 431.16 | 1.232 | 433.77 | 1.239 | 2.62 | 0.61% |
| 400 | 35.69 | 0.089 | 33.02 | 0.083 | (2.67) | -7.48% | 491.49 | 1.229 | 494.06 | 1.235 | 2.57 | 0.52% |
| 450 | 39.05 | 0.087 | 35.68 | 0.079 | (3.37) | -8.63% | 551.83 | 1.226 | 554.35 | 1.232 | 2.52 | 0.46% |
| 500 | 42.41 | 0.085 | 38.34 | 0.077 | (4.07) | -9.60% | 612.16 | 1.224 | 614.64 | 1.229 | 2.48 | 0.41% |
| 750 | 59.21 | 0.079 | 51.64 | 0.069 | (7.57) | -12.79% | 913.84 | 1.218 | 916.09 | 1.221 | 2.25 | 0.25% |
| 1,000 | 76.01 | 0.076 | 64.94 | 0.065 | (11.07) | -14.56% | 1,215.51 | 1.216 | 1,217.54 | 1.218 | 2.03 | 0.17% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 60 | 10.90 | 0.182 | 13.40 | 0.223 | 2.50 | 22.92% | 79.27 | 1.321 | 82.55 | 1.376 | 3.28 | 4.14% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 100 | 15.53 | 0.155 | 17.06 | 0.171 | 1.53 | 9.85% | 129.48 | 1.295 | 132.32 | 1.323 | 2.84 | 2.19% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 150 | 18.69 | 0.126 | 19.72 | 0.131 | 0.83 | 4.39% | 189.62 | 1.265 | 192.61 | 1.284 | 2.79 | 1.47% |

Equivalent DRY Therm Present Rate R-4

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $3.95 | /Customer |
| First | 100 | $0.1158 | /therm |
| Over | 100 | $0.0672 | /therm |
| TOTAL CGC & LDAC | | $1.1395 | /therm |
| CGC | | $1.1206 | |
| LDAC | | $0.0189 | |

Proposed Rate R-4

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $7.90 | /Customer |
| First | 100 | $0.0916 | /therm |
| Over | 100 | $0.0532 | /therm |
| TOTAL CGC & LDAC | | $1.1526 | /therm |
| CGC | | $1.1337 | /therm |
| LDAC | | $0.0189 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Summer Season
Low Income Residential Heating
Rate R-4

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $3.95 | NA | $7.90 | NA | $3.95 | 100.00% | $3.95 | NA | $7.90 | NA | $3.95 | 100.00% |
| 10 | 5.11 | 0.511 | 8.82 | 0.882 | 3.71 | 72.59% | 14.92 | 1.492 | 18.76 | 1.876 | 3.84 | 25.75% |
| 25 | 6.60 | 0.264 | 10.00 | 0.400 | 3.40 | 51.44% | 31.13 | 1.245 | 34.86 | 1.394 | 3.73 | 11.98% |
| 50 | 8.28 | 0.166 | 11.33 | 0.227 | 3.05 | 36.78% | 57.33 | 1.147 | 61.04 | 1.221 | 3.71 | 6.47% |
| 75 | 9.96 | 0.133 | 12.66 | 0.169 | 2.70 | 27.06% | 83.54 | 1.114 | 87.23 | 1.163 | 3.69 | 4.42% |
| 100 | 11.64 | 0.116 | 13.99 | 0.140 | 2.35 | 20.15% | 109.74 | 1.097 | 113.42 | 1.134 | 3.68 | 3.35% |
| 125 | 13.32 | 0.107 | 15.32 | 0.123 | 2.00 | 14.98% | 135.95 | 1.088 | 139.61 | 1.117 | 3.66 | 2.69% |
| 150 | 15.00 | 0.100 | 16.65 | 0.111 | 1.65 | 10.97% | 162.15 | 1.081 | 165.79 | 1.105 | 3.64 | 2.25% |
| 175 | 16.68 | 0.095 | 17.98 | 0.103 | 1.30 | 7.77% | 188.36 | 1.076 | 191.98 | 1.097 | 3.62 | 1.92% |
| 200 | 18.36 | 0.092 | 19.31 | 0.097 | 0.95 | 5.15% | 214.56 | 1.073 | 218.17 | 1.091 | 3.61 | 1.68% |
| 225 | 20.04 | 0.089 | 20.64 | 0.092 | 0.60 | 2.97% | 240.77 | 1.070 | 244.36 | 1.086 | 3.59 | 1.49% |
| 250 | 21.72 | 0.087 | 21.97 | 0.088 | 0.25 | 1.13% | 266.97 | 1.068 | 270.54 | 1.082 | 3.57 | 1.34% |
| 275 | 23.40 | 0.085 | 23.30 | 0.085 | (0.10) | -0.44% | 293.18 | 1.066 | 296.73 | 1.079 | 3.55 | 1.21% |
| 300 | 25.08 | 0.084 | 24.63 | 0.082 | (0.45) | -1.81% | 319.38 | 1.065 | 322.92 | 1.076 | 3.54 | 1.11% |
| 350 | 28.44 | 0.081 | 27.29 | 0.078 | (1.15) | -4.06% | 371.79 | 1.062 | 375.29 | 1.072 | 3.50 | 0.94% |
| 400 | 31.80 | 0.080 | 29.95 | 0.075 | (1.85) | -5.83% | 424.20 | 1.061 | 427.67 | 1.069 | 3.47 | 0.82% |
| 450 | 35.16 | 0.078 | 32.61 | 0.072 | (2.55) | -7.26% | 476.61 | 1.059 | 480.04 | 1.067 | 3.43 | 0.72% |
| 500 | 38.52 | 0.077 | 35.27 | 0.071 | (3.25) | -8.45% | 529.02 | 1.058 | 532.42 | 1.065 | 3.40 | 0.64% |
| 750 | 55.32 | 0.074 | 48.57 | 0.065 | (6.75) | -12.21% | 791.07 | 1.055 | 794.29 | 1.059 | 3.22 | 0.41% |
| 1,000 | 72.12 | 0.072 | 61.87 | 0.062 | (10.25) | -14.22% | 1,053.12 | 1.053 | 1,056.17 | 1.056 | 3.05 | 0.29% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 15 | 5.69 | 0.379 | 9.27 | 0.618 | 3.59 | 63.07% | 20.40 | 1.360 | 24.19 | 1.613 | 3.79 | 18.56% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 25 | 6.60 | 0.264 | 10.00 | 0.400 | 3.40 | 51.44% | 31.13 | 1.245 | 34.86 | 1.394 | 3.73 | 11.98% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 40 | 7.61 | 0.190 | 10.80 | 0.270 | 3.19 | 41.87% | 46.85 | 1.171 | 50.57 | 1.264 | 3.72 | 7.94% |

Equivalent DRY Therm Present Rate R-4

| | Block therm | Rate |
|---|---|---|
| Customer Charge | - | $3.95 /Customer |
| First | 20 | $0.1158 /therm |
| Over | 20 | $0.0672 /therm |
| TOTAL CGC & LDAC | | $0.9810 /therm |
| CGC | | $0.9423 |
| LDAC | | $0.0387 |

Proposed Rate R-4

| | Block therm | Rate |
|---|---|---|
| Customer Charge | - | $7.90 /Customer |
| First | 20 | $0.0916 /therm |
| Over | 20 | $0.0532 /therm |
| TOTAL CGC & LDAC | | $0.9943 /therm |
| CGC | | $0.9556 /therm |
| LDAC | | $0.0387 /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

# NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Winter Season
C&I - Low Annual Use, High Winter Use
Rate G-41

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $24.64 | NA | $50.00 | NA | $25.36 | 102.92% | $24.64 | NA | $50.00 | NA | $25.36 | 102.92% |
| 10 | 27.86 | 2.786 | 52.27 | 5.227 | 24.41 | 87.62% | 39.16 | 3.916 | 63.70 | 6.370 | 24.54 | 62.66% |
| 25 | 32.69 | 1.307 | 55.67 | 2.227 | 22.99 | 70.32% | 60.95 | 2.438 | 84.26 | 3.370 | 23.31 | 38.25% |
| 50 | 40.73 | 0.815 | 61.34 | 1.227 | 20.61 | 50.60% | 97.26 | 1.945 | 118.52 | 2.370 | 21.27 | 21.87% |
| 75 | 48.78 | 0.650 | 67.01 | 0.893 | 18.24 | 37.39% | 133.56 | 1.781 | 152.78 | 2.037 | 19.22 | 14.39% |
| 100 | 56.82 | 0.568 | 72.68 | 0.727 | 15.86 | 27.91% | 169.87 | 1.699 | 187.04 | 1.870 | 17.17 | 10.11% |
| 150 | 67.29 | 0.449 | 80.06 | 0.534 | 12.77 | 18.98% | 236.86 | 1.579 | 251.60 | 1.677 | 14.74 | 6.22% |
| 200 | 77.75 | 0.389 | 87.43 | 0.437 | 9.68 | 12.45% | 303.85 | 1.519 | 316.15 | 1.581 | 12.30 | 4.05% |
| 250 | 88.22 | 0.353 | 94.81 | 0.379 | 6.59 | 7.47% | 370.84 | 1.483 | 380.71 | 1.523 | 9.86 | 2.66% |
| 300 | 98.68 | 0.329 | 102.18 | 0.341 | 3.50 | 3.55% | 437.83 | 1.459 | 445.26 | 1.484 | 7.43 | 1.70% |
| 350 | 109.15 | 0.312 | 109.56 | 0.313 | 0.41 | 0.38% | 504.82 | 1.442 | 509.82 | 1.457 | 5.00 | 0.99% |
| 400 | 119.61 | 0.299 | 116.93 | 0.292 | (2.68) | -2.24% | 571.81 | 1.430 | 574.37 | 1.436 | 2.56 | 0.45% |
| 500 | 140.54 | 0.281 | 131.68 | 0.263 | (8.86) | -6.30% | 705.79 | 1.412 | 703.48 | 1.407 | (2.31) | -0.33% |
| 600 | 161.47 | 0.269 | 146.43 | 0.244 | (15.04) | -9.31% | 839.77 | 1.400 | 832.59 | 1.388 | (7.18) | -0.85% |
| 700 | 182.40 | 0.261 | 161.18 | 0.230 | (21.22) | -11.63% | 973.75 | 1.391 | 961.70 | 1.374 | (12.05) | -1.24% |
| 800 | 203.33 | 0.254 | 175.93 | 0.220 | (27.40) | -13.48% | 1,107.73 | 1.385 | 1,090.81 | 1.364 | (16.92) | -1.53% |
| 900 | 224.26 | 0.249 | 190.68 | 0.212 | (33.58) | -14.97% | 1,241.71 | 1.380 | 1,219.92 | 1.355 | (21.79) | -1.75% |
| 1,000 | 245.19 | 0.245 | 205.43 | 0.205 | (39.76) | -16.22% | 1,375.69 | 1.376 | 1,349.03 | 1.349 | (26.66) | -1.94% |
| 1,250 | 297.52 | 0.238 | 242.31 | 0.194 | (55.21) | -18.56% | 1,710.64 | 1.369 | 1,671.81 | 1.337 | (38.83) | -2.27% |
| 1,500 | 349.84 | 0.233 | 279.18 | 0.186 | (70.66) | -20.20% | 2,045.59 | 1.364 | 1,994.58 | 1.330 | (51.01) | -2.49% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 70 | 47.17 | 0.674 | 65.88 | 0.941 | 18.71 | 39.67% | 126.30 | 1.804 | 145.93 | 2.085 | 19.63 | 15.54% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 175 | 72.52 | 0.414 | 83.74 | 0.479 | 11.23 | 15.46% | 270.36 | 1.545 | 283.87 | 1.622 | 13.52 | 5.00% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 450 | 130.08 | 0.289 | 124.31 | 0.276 | (5.77) | -4.44% | 638.80 | 1.420 | 638.93 | 1.420 | 0.13 | 0.02% |

**Equivalent DRY Therm Present Rate G-41**

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $24.64 | /Customer |
| First | 100 | $0.3218 | /therm |
| Over | 100 | $0.2093 | /therm |
| TOTAL CGC & LDAC | | $1.1305 | /therm |
| CGC | | $1.1206 | |
| LDAC | | $0.0099 | |

**Proposed Rate G-41**

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $50.00 | /Customer |
| First | 100 | $0.2268 | /therm |
| Over | 100 | $0.1475 | /therm |
| TOTAL CGC & LDAC | | $1.1436 | /therm |
| CGC | | $1.1337 | /therm |
| LDAC | | $0.0099 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

# NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Summer Season
C&I - Low Annual Use, High Winter Use
Rate G-41

| Sales therm | Present Rate Base Rate | Present Rate Revenues Per therm | Proposed Rate Base Rate | Proposed Rate Revenues Per therm | Difference Revenues Base Rate | Difference Percent Base Rate | Present Rate With CGC Revenues Rate | Present Rate With CGC Revenues Revenues Per therm | Proposed Rate With CGC Revenues Rate | Proposed Rate With CGC Revenues Revenues Per therm | Difference With CGC Revenues Revenues Rate | Difference With CGC Revenues Percent Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | $24.64 | NA | $50.00 | NA | $25.36 | 102.92% | $24.64 | NA | $50.00 | NA | $25.36 | 102.92% |
| 10 | 27.86 | 2.786 | 52.27 | 5.227 | 24.41 | 87.62% | 37.65 | 3.765 | 62.19 | 6.219 | 24.54 | 65.19% |
| 25 | 32.12 | 1.285 | 55.27 | 2.211 | 23.15 | 72.07% | 56.59 | 2.264 | 80.07 | 3.203 | 23.48 | 41.49% |
| 50 | 37.36 | 0.747 | 58.96 | 1.179 | 21.61 | 57.84% | 86.29 | 1.726 | 108.56 | 2.171 | 22.27 | 25.80% |
| 75 | 42.59 | 0.568 | 62.65 | 0.835 | 20.06 | 47.11% | 115.99 | 1.547 | 137.04 | 1.827 | 21.05 | 18.15% |
| 100 | 47.82 | 0.478 | 66.34 | 0.663 | 18.52 | 38.72% | 145.69 | 1.457 | 165.53 | 1.655 | 19.84 | 13.62% |
| 150 | 58.29 | 0.389 | 73.71 | 0.491 | 15.43 | 26.47% | 205.09 | 1.367 | 222.50 | 1.483 | 17.41 | 8.49% |
| 200 | 68.75 | 0.344 | 81.09 | 0.405 | 12.34 | 17.94% | 264.49 | 1.322 | 279.47 | 1.397 | 14.98 | 5.66% |
| 250 | 79.22 | 0.317 | 88.46 | 0.354 | 9.25 | 11.67% | 323.89 | 1.296 | 336.44 | 1.346 | 12.55 | 3.87% |
| 300 | 89.68 | 0.299 | 95.84 | 0.319 | 6.16 | 6.86% | 383.29 | 1.278 | 393.41 | 1.311 | 10.12 | 2.64% |
| 350 | 100.15 | 0.286 | 103.21 | 0.295 | 3.07 | 3.06% | 442.69 | 1.265 | 450.39 | 1.287 | 7.69 | 1.74% |
| 400 | 110.61 | 0.277 | 110.59 | 0.276 | (0.02) | -0.02% | 502.09 | 1.255 | 507.35 | 1.268 | 5.26 | 1.05% |
| 500 | 131.54 | 0.263 | 125.34 | 0.251 | (6.20) | -4.72% | 620.89 | 1.242 | 621.29 | 1.243 | 0.40 | 0.06% |
| 600 | 152.47 | 0.254 | 140.09 | 0.233 | (12.38) | -8.12% | 739.69 | 1.233 | 735.23 | 1.225 | (4.46) | -0.60% |
| 700 | 173.40 | 0.248 | 154.84 | 0.221 | (18.56) | -10.71% | 858.49 | 1.226 | 849.17 | 1.213 | (9.32) | -1.09% |
| 800 | 194.33 | 0.243 | 169.59 | 0.212 | (24.74) | -12.73% | 977.29 | 1.222 | 963.11 | 1.204 | (14.18) | -1.45% |
| 900 | 215.26 | 0.239 | 184.34 | 0.205 | (30.92) | -14.37% | 1,096.09 | 1.218 | 1,077.05 | 1.197 | (19.04) | -1.74% |
| 1,000 | 236.19 | 0.236 | 199.09 | 0.199 | (37.10) | -15.71% | 1,214.89 | 1.215 | 1,190.99 | 1.191 | (23.90) | -1.97% |
| 1,250 | 288.52 | 0.231 | 235.96 | 0.189 | (52.55) | -18.22% | 1,511.89 | 1.210 | 1,475.84 | 1.181 | (36.05) | -2.38% |
| 1,500 | 340.84 | 0.227 | 272.84 | 0.182 | (68.00) | -19.95% | 1,808.89 | 1.206 | 1,760.69 | 1.174 | (48.20) | -2.66% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| - | 24.64 | | 50.00 | 0.000 | 25.36 | 102.92% | 24.64 | 0.000 | 50.00 | 0.000 | 25.36 | 102.92% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 10 | 27.86 | 2.786 | 52.27 | 5.227 | 24.41 | 87.62% | 37.65 | 3.765 | 62.19 | 6.219 | 24.54 | 65.19% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 55 | 38.40 | 0.698 | 59.70 | 1.085 | 21.30 | 55.46% | 92.23 | 1.677 | 114.25 | 2.077 | 22.02 | 23.88% |

| Equivalent DRY Therm Present Rate | Block therm | Rate G-41 | |
|---|---|---|---|
| Customer Charge | - | $24.64 | /Customer |
| First | 20 | $0.3218 | /therm |
| Over | 20 | $0.2093 | /therm |
| TOTAL CGC & LDAC | | $0.9787 | /therm |
| CGC | | $0.9451 | |
| LDAC | | $0.0336 | |

| Proposed Rate | Block therm | Rate G-41 | |
|---|---|---|---|
| Customer Charge | - | $50.00 | /Customer |
| First | 20 | $0.2266 | /therm |
| Over | 20 | $0.1475 | /therm |
| TOTAL CGC & LDAC | | $0.9919 | /therm |
| CGC | | $0.9583 | /therm |
| LDAC | | $0.0336 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms)

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Winter Season
C&I - Medium Annual Use, High Winter Use
Rate G-42

| | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sales therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $69.36 | NA | $140.00 | NA | $70.64 | 101.85% | $69.36 | NA | $140.00 | NA | $70.64 | 101.85% |
| 10 | 72.03 | 7.203 | 142.48 | 14.248 | 70.45 | 97.80% | 83.33 | 8.333 | 153.91 | 15.391 | 70.58 | 84.69% |
| 25 | 76.03 | 3.041 | 146.19 | 5.848 | 70.16 | 92.27% | 104.30 | 4.172 | 174.78 | 6.991 | 70.49 | 67.58% |
| 50 | 82.71 | 1.654 | 152.38 | 3.048 | 69.68 | 84.25% | 139.23 | 2.785 | 209.56 | 4.191 | 70.33 | 50.51% |
| 75 | 89.38 | 1.192 | 158.57 | 2.114 | 69.19 | 77.42% | 174.17 | 2.322 | 244.34 | 3.258 | 70.18 | 40.29% |
| 100 | 96.05 | 0.961 | 164.76 | 1.648 | 68.71 | 71.54% | 209.10 | 2.091 | 279.12 | 2.791 | 70.02 | 33.49% |
| 150 | 109.40 | 0.729 | 177.14 | 1.181 | 67.75 | 61.93% | 278.97 | 1.860 | 348.68 | 2.325 | 69.71 | 24.99% |
| 200 | 122.74 | 0.614 | 189.52 | 0.948 | 66.78 | 54.41% | 348.84 | 1.744 | 418.24 | 2.091 | 69.40 | 19.89% |
| 250 | 136.09 | 0.544 | 201.90 | 0.808 | 65.82 | 48.36% | 418.71 | 1.675 | 487.80 | 1.951 | 69.09 | 16.50% |
| 300 | 149.43 | 0.498 | 214.28 | 0.714 | 64.85 | 43.40% | 488.58 | 1.629 | 557.36 | 1.858 | 68.78 | 14.08% |
| 350 | 162.78 | 0.465 | 226.66 | 0.648 | 63.89 | 39.25% | 558.45 | 1.596 | 626.92 | 1.791 | 68.47 | 12.26% |
| 400 | 176.12 | 0.440 | 239.04 | 0.598 | 62.92 | 35.73% | 628.32 | 1.571 | 696.48 | 1.741 | 68.16 | 10.85% |
| 500 | 202.81 | 0.406 | 263.80 | 0.528 | 60.99 | 30.07% | 768.06 | 1.536 | 835.60 | 1.671 | 67.54 | 8.79% |
| 750 | 269.54 | 0.359 | 325.70 | 0.434 | 56.17 | 20.84% | 1,117.41 | 1.490 | 1,183.40 | 1.578 | 65.99 | 5.91% |
| 1,000 | 336.26 | 0.336 | 387.60 | 0.388 | 51.34 | 15.27% | 1,466.76 | 1.467 | 1,531.20 | 1.531 | 64.44 | 4.39% |
| 1,500 | 424.41 | 0.283 | 469.40 | 0.313 | 44.99 | 10.60% | 2,120.16 | 1.413 | 2,184.80 | 1.457 | 64.64 | 3.05% |
| 2,000 | 512.56 | 0.256 | 551.20 | 0.276 | 38.64 | 7.54% | 2,773.56 | 1.387 | 2,838.40 | 1.419 | 64.84 | 2.34% |
| 3,000 | 688.86 | 0.230 | 714.80 | 0.238 | 25.94 | 3.77% | 4,080.36 | 1.360 | 4,145.60 | 1.382 | 65.24 | 1.60% |
| 4,000 | 865.16 | 0.216 | 878.40 | 0.220 | 13.24 | 1.53% | 5,387.16 | 1.347 | 5,452.80 | 1.363 | 65.64 | 1.22% |
| 5,000 | 1,041.46 | 0.208 | 1,042.00 | 0.208 | 0.54 | 0.05% | 6,693.96 | 1.339 | 6,760.00 | 1.352 | 66.04 | 0.99% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 1,200 | 371.52 | 0.310 | 420.32 | 0.350 | 48.80 | 13.14% | 1,728.12 | 1.440 | 1,792.64 | 1.494 | 64.52 | 3.73% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 2,000 | 512.56 | 0.256 | 551.20 | 0.276 | 38.64 | 7.54% | 2,773.56 | 1.387 | 2,838.40 | 1.419 | 64.84 | 2.34% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 3,500 | 777.01 | 0.222 | 796.60 | 0.220 | 19.59 | 2.52% | 4,733.76 | 1.353 | 4,799.20 | 1.371 | 65.44 | 1.38% |

Equivalent DRY Therm Present Rate G-42

| | Block therm | Rate |
|---|---|---|
| Customer Charge | - | $69.36 /Customer |
| First | 1,000 | $0.2669 /therm |
| Over | 1,000 | $0.1763 /therm |
| TOTAL CGC & LDAC | | $1.1305 /therm |
| CGC | | $1.1206 |
| LDAC | | $0.0099 |

Proposed Rate G-42

| | Block therm | Rate |
|---|---|---|
| Customer Charge | - | $140.00 /Customer |
| First | 1,000 | $0.2476 /therm |
| Over | 1,000 | $0.1636 /therm |
| TOTAL CGC & LDAC | | $1.1436 /therm |
| CGC | | $1.1337 /therm |
| LDAC | | $0.0099 /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

# NATIONAL GRID - NH
## Comparison of Present and Proposed Rates
## Summer Season
## C&I - Medium Annual Use, High Winter Use
## Rate G-42

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $69.36 | NA | $140.00 | NA | $70.64 | 101.85% | $69.36 | NA | $140.00 | NA | $70.64 | 101.85% |
| 10 | 72.03 | 7.203 | 142.48 | 14.248 | 70.45 | 97.80% | 81.82 | 8.182 | 152.40 | 15.240 | 70.58 | 86.27% |
| 25 | 76.03 | 3.041 | 146.19 | 5.848 | 70.16 | 92.27% | 100.50 | 4.020 | 170.99 | 6.840 | 70.49 | 70.14% |
| 50 | 82.71 | 1.654 | 152.38 | 3.048 | 69.66 | 84.25% | 131.64 | 2.633 | 201.98 | 4.040 | 70.34 | 53.43% |
| 75 | 89.38 | 1.192 | 158.57 | 2.114 | 69.19 | 77.42% | 162.78 | 2.170 | 232.96 | 3.106 | 70.18 | 43.11% |
| 100 | 96.05 | 0.961 | 164.76 | 1.648 | 68.71 | 71.54% | 193.92 | 1.939 | 263.95 | 2.640 | 70.03 | 36.11% |
| 150 | 109.40 | 0.729 | 177.14 | 1.181 | 67.75 | 61.93% | 256.20 | 1.708 | 325.93 | 2.173 | 69.72 | 27.22% |
| 200 | 122.74 | 0.614 | 189.52 | 0.948 | 66.78 | 54.41% | 318.48 | 1.592 | 387.90 | 1.940 | 69.42 | 21.80% |
| 250 | 136.09 | 0.544 | 201.90 | 0.808 | 65.82 | 48.36% | 380.76 | 1.523 | 449.88 | 1.800 | 69.12 | 18.15% |
| 300 | 149.43 | 0.498 | 214.28 | 0.714 | 64.85 | 43.40% | 443.04 | 1.477 | 511.85 | 1.706 | 68.81 | 15.53% |
| 350 | 162.78 | 0.465 | 226.66 | 0.648 | 63.89 | 39.25% | 505.32 | 1.444 | 573.83 | 1.640 | 68.51 | 13.56% |
| 400 | 176.12 | 0.440 | 239.04 | 0.598 | 62.92 | 35.73% | 567.60 | 1.419 | 635.80 | 1.590 | 68.20 | 12.02% |
| 500 | 193.75 | 0.388 | 255.40 | 0.511 | 61.65 | 31.82% | 683.10 | 1.366 | 751.35 | 1.503 | 68.25 | 9.99% |
| 750 | 237.83 | 0.317 | 296.30 | 0.395 | 58.46 | 24.59% | 971.85 | 1.296 | 1,040.23 | 1.387 | 68.38 | 7.04% |
| 1,000 | 281.90 | 0.282 | 337.20 | 0.337 | 55.30 | 19.62% | 1,260.60 | 1.261 | 1,329.10 | 1.329 | 68.50 | 5.43% |
| 1,500 | 370.05 | 0.247 | 419.00 | 0.279 | 48.95 | 13.23% | 1,838.10 | 1.225 | 1,906.85 | 1.271 | 68.75 | 3.74% |
| 2,000 | 458.20 | 0.229 | 500.80 | 0.250 | 42.60 | 9.30% | 2,415.60 | 1.208 | 2,484.60 | 1.242 | 69.00 | 2.86% |
| 3,000 | 634.50 | 0.212 | 664.40 | 0.221 | 29.90 | 4.71% | 3,570.60 | 1.190 | 3,640.10 | 1.213 | 69.50 | 1.95% |
| 4,000 | 810.80 | 0.203 | 828.00 | 0.207 | 17.20 | 2.12% | 4,725.60 | 1.181 | 4,795.60 | 1.199 | 70.00 | 1.48% |
| 5,000 | 987.10 | 0.197 | 991.60 | 0.198 | 4.50 | 0.46% | 5,880.60 | 1.176 | 5,951.10 | 1.190 | 70.50 | 1.20% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 55 | 84.04 | 1.528 | 153.62 | 2.793 | 69.58 | 82.79% | 137.87 | 2.507 | 208.17 | 3.785 | 70.30 | 50.99% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 400 | 176.12 | 0.440 | 239.04 | 0.598 | 62.92 | 35.73% | 567.60 | 1.419 | 635.80 | 1.590 | 68.20 | 12.02% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 650 | 255.46 | 0.301 | 312.66 | 0.368 | 57.20 | 22.39% | 1,087.35 | 1.279 | 1,155.78 | 1.360 | 68.43 | 6.29% |

| Equivalent DRY Therm Present Rate | Block therm | G-42 Rate | |
|---|---|---|---|
| Customer Charge | - | $69.36 | /Customer |
| First | 400 | $0.2669 | /therm |
| Over | 400 | $0.1763 | /therm |
| TOTAL CGC & LDAC | | $0.9787 | /therm |
| CGC | | $0.9451 | |
| LDAC | | $0.0336 | |

| Proposed Rate | Block therm | G-42 Rate | |
|---|---|---|---|
| Customer Charge | - | $140.00 | /Customer |
| First | 400 | $0.2476 | /therm |
| Over | 400 | $0.1636 | /therm |
| TOTAL CGC & LDAC | | $0.9919 | /therm |
| CGC | | $0.9583 | /therm |
| LDAC | | $0.0336 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

# NATIONAL GRID - NH
## Comparison of Present and Proposed Rates
## Winter Season
## C&I - High Annual Use, High Winter Use
## Rate G-43

| | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sales therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $299.39 | NA | $600.00 | NA | $300.61 | 100.41% | $299.39 | NA | $600.00 | NA | $300.61 | 100.41% |
| 500 | 377.54 | 0.755 | 682.45 | 1.365 | 304.91 | 80.76% | 942.79 | 1.886 | 1,254.25 | 2.509 | 311.46 | 33.04% |
| 1,000 | 455.69 | 0.456 | 764.90 | 0.765 | 309.21 | 67.86% | 1,586.19 | 1.586 | 1,908.50 | 1.909 | 322.31 | 20.32% |
| 1,250 | 494.77 | 0.396 | 806.13 | 0.645 | 311.36 | 62.93% | 1,907.69 | 1.526 | 2,235.63 | 1.789 | 327.74 | 17.18% |
| 1,500 | 533.84 | 0.356 | 847.35 | 0.565 | 313.51 | 58.73% | 2,229.59 | 1.486 | 2,562.75 | 1.709 | 333.16 | 14.94% |
| 1,750 | 572.92 | 0.327 | 888.50 | 0.508 | 315.66 | 55.10% | 2,551.29 | 1.458 | 2,889.88 | 1.651 | 338.59 | 13.27% |
| 2,000 | 611.99 | 0.306 | 929.80 | 0.465 | 317.81 | 51.93% | 2,872.99 | 1.436 | 3,217.00 | 1.609 | 344.01 | 11.97% |
| 2,500 | 690.14 | 0.276 | 1,012.25 | 0.405 | 322.11 | 46.67% | 3,516.39 | 1.407 | 3,871.25 | 1.549 | 354.86 | 10.09% |
| 3,000 | 768.29 | 0.256 | 1,094.70 | 0.365 | 326.41 | 42.49% | 4,159.79 | 1.387 | 4,525.50 | 1.509 | 365.71 | 8.79% |
| 3,500 | 846.44 | 0.242 | 1,177.15 | 0.336 | 330.71 | 39.07% | 4,803.19 | 1.372 | 5,179.75 | 1.480 | 376.56 | 7.84% |
| 4,000 | 924.59 | 0.231 | 1,259.60 | 0.315 | 335.01 | 36.23% | 5,446.59 | 1.362 | 5,834.00 | 1.459 | 387.41 | 7.11% |
| 4,500 | 1,002.74 | 0.223 | 1,342.05 | 0.298 | 339.31 | 33.84% | 6,089.99 | 1.353 | 6,488.25 | 1.442 | 398.26 | 6.54% |
| 5,000 | 1,080.89 | 0.216 | 1,424.50 | 0.285 | 343.61 | 31.79% | 6,733.39 | 1.347 | 7,142.50 | 1.429 | 409.11 | 6.08% |
| 6,000 | 1,237.19 | 0.206 | 1,589.40 | 0.265 | 352.21 | 28.47% | 8,020.19 | 1.337 | 8,451.00 | 1.409 | 430.81 | 5.37% |
| 7,000 | 1,393.49 | 0.199 | 1,754.30 | 0.251 | 360.81 | 25.89% | 9,306.99 | 1.330 | 9,759.50 | 1.394 | 452.51 | 4.86% |
| 8,000 | 1,549.79 | 0.194 | 1,919.20 | 0.240 | 369.41 | 23.84% | 10,593.79 | 1.324 | 11,068.00 | 1.384 | 474.21 | 4.48% |
| 9,000 | 1,706.09 | 0.190 | 2,084.10 | 0.232 | 378.01 | 22.16% | 11,880.59 | 1.320 | 12,376.50 | 1.375 | 495.91 | 4.17% |
| 10,000 | 1,862.39 | 0.186 | 2,249.00 | 0.225 | 386.61 | 20.76% | 13,167.39 | 1.317 | 13,685.00 | 1.369 | 517.61 | 3.93% |
| 15,000 | 2,643.89 | 0.176 | 3,073.50 | 0.205 | 429.61 | 16.25% | 19,601.39 | 1.307 | 20,227.50 | 1.349 | 626.11 | 3.19% |
| 20,000 | 3,425.39 | 0.171 | 3,898.00 | 0.195 | 472.61 | 13.80% | 26,035.39 | 1.302 | 26,770.00 | 1.339 | 734.61 | 2.82% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 3,500 | 846.44 | 0.242 | 1,177.15 | 0.336 | 330.71 | 39.07% | 4,803.19 | 1.372 | 5,179.75 | 1.480 | 376.56 | 7.84% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 10,000 | 1,862.39 | 0.186 | 2,249.00 | 0.225 | 386.61 | 20.76% | 13,167.39 | 1.317 | 13,686.00 | 1.369 | 517.61 | 3.93% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 20,000 | 3,425.39 | 0.171 | 3,898.00 | 0.195 | 472.61 | 13.80% | 26,035.39 | 1.302 | 26,770.00 | 1.339 | 734.61 | 2.82% |

| Equivalent DRY Therm Present Rate | Block therm | G-43 Rate | |
|---|---|---|---|
| Customer Charge | - | $299.39 | /Customer |
| First | - | $0.1563 | /therm |
| Over | - | $0.1563 | /therm |
| TOTAL CGC & LDAC | | $1.1305 | /therm |
| CGC | | $1.1206 | |
| LDAC | | $0.0099 | |

| Proposed Rate | Block therm | G-43 Rate | |
|---|---|---|---|
| Customer Charge | - | $600.00 | /Customer |
| First | - | $0.1649 | /therm |
| Over | - | $0.1649 | /therm |
| TOTAL CGC & LDAC | | $1.1436 | /therm |
| CGC | | $1.1337 | /therm |
| LDAC | | $0.0099 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Summer Season
C&I - High Annual Use, High Winter Use
Rate G-43

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $299 39 | NA | $600.00 | NA | $300.61 | 100.41% | $299 39 | NA | $600.00 | NA | $300.61 | 100.41% |
| 500 | 336.14 | 0.670 | 637.70 | 1.275 | 302.56 | 90.26% | 824.49 | 1.649 | 1,133.65 | 2.267 | 309.16 | 37.50% |
| 1,000 | 370.89 | 0.371 | 675.40 | 0.675 | 304.51 | 82.10% | 1,349.59 | 1.350 | 1,667.30 | 1.667 | 317.71 | 23.54% |
| 1,250 | 388 77 | 0.311 | 694.25 | 0.555 | 305 49 | 78 58% | 1,612 14 | 1 290 | 1,934 13 | 1 547 | 321.99 | 19.97% |
| 1,500 | 406.64 | 0.271 | 713.10 | 0.475 | 306 46 | 75.36% | 1,874 69 | 1 250 | 2,200 95 | 1 467 | 326 26 | 17 40% |
| 1,750 | 424 52 | 0.243 | 731 95 | 0.418 | 307 44 | 72.42% | 2,137.24 | 1.221 | 2,467.78 | 1 410 | 330 54 | 15 47% |
| 2,000 | 442.39 | 0.221 | 750.80 | 0.375 | 308.41 | 69.71% | 2,399.79 | 1.200 | 2,734.60 | 1.367 | 334.81 | 13 95% |
| 2,500 | 478.14 | 0.191 | 788.50 | 0 315 | 310.36 | 64.91% | 2,924 89 | 1.170 | 3,268.25 | 1.307 | 343.36 | 11.74% |
| 3,000 | 513 89 | 0 171 | 826.20 | 0.275 | 312.31 | 60.77% | 3,449 99 | 1 150 | 3,801.90 | 1.267 | 351.91 | 10 20% |
| 3,500 | 549 64 | 0.157 | 863.90 | 0 247 | 314.26 | 57 18% | 3,975 09 | 1.136 | 4,335 55 | 1 239 | 360 46 | 9 07% |
| 4,000 | 585.39 | 0.146 | 901.60 | 0.225 | 316.21 | 54.02% | 4,500.19 | 1.125 | 4,869.20 | 1.217 | 369.01 | 8.20% |
| 4,500 | 621.14 | 0.138 | 939.30 | 0.209 | 318.16 | 51.22% | 5,025.29 | 1.117 | 5,402.85 | 1.201 | 377.56 | 7.51% |
| 5,000 | 656.89 | 0.131 | 977.00 | 0.195 | 320.11 | 48.73% | 5,550.39 | 1 110 | 5,936.50 | 1.187 | 386.11 | 6.95% |
| 6,000 | 728.39 | 0.121 | 1,052.40 | 0.175 | 324 01 | 44 48% | 6,600.59 | 1 100 | 7,003.60 | 1.167 | 403 21 | 6.11% |
| 7,000 | 799.89 | 0.114 | 1,127.80 | 0.161 | 327 91 | 40.99% | 7,650.79 | 1.093 | 8,071.10 | 1.153 | 420.31 | 5 49% |
| 8,000 | 871.39 | 0.109 | 1,203.20 | 0.150 | 331.81 | 38.08% | 8,700.99 | 1.088 | 9,138.40 | 1.142 | 437.41 | 5.03% |
| 9,000 | 942.89 | 0 105 | 1,278.60 | 0.142 | 335.71 | 35.60% | 9,751.19 | 1.083 | 10,205.70 | 1.134 | 454.51 | 4.66% |
| 10,000 | 1,014 39 | 0.101 | 1,354 00 | 0.135 | 339 61 | 33.48% | 10,801.39 | 1.080 | 11,273 00 | 1.127 | 471.61 | 4 37% |
| 15,000 | 1,371 89 | 0.091 | 1,731 00 | 0.115 | 359.11 | 26 18% | 16,052.39 | 1.070 | 16,609.50 | 1.107 | 557 11 | 3 47% |
| 20,000 | 1,729.39 | 0.086 | 2,108.00 | 0.105 | 378.61 | 21.89% | 21,303.39 | 1.065 | 21,946 00 | 1.097 | 642.61 | 3.02% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 250 | 317 27 | 1 269 | 618 85 | 2.475 | 301.59 | 95.06% | 561.94 | 2.248 | 866 03 | 3.467 | 304.89 | 54.26% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 2,000 | 442.39 | 0.221 | 750.80 | 0.375 | 308.41 | 69.71% | 2,399.79 | 1.200 | 2,734.60 | 1.367 | 334.81 | 13.95% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 7,000 | 799 89 | 0.114 | 1,127.80 | 0.161 | 327 91 | 40.99% | 7,650 79 | 1 093 | 8,071 10 | 1 153 | 420 31 | 5 49% |

| Equivalent DRY Therm Present Rate | Block therm | G-43 Rate | |
|---|---|---|---|
| Customer Charge | - | $299.39 | /Customer |
| First | - | $0 0715 | /therm |
| Over | - | $0.0715 | /therm |
| TOTAL CGC & LDAC | | $0.9787 | /therm |
| CGC | | $0.9451 | |
| LDAC | | $0 0336 | |

| Proposed Rate | Block therm | G-43 Rate | |
|---|---|---|---|
| Customer Charge | - | $600.00 | /Customer |
| First | - | $0 0754 | /therm |
| Over | - | $0.0754 | /therm |
| TOTAL CGC & LDAC | | $0.9919 | /therm |
| CGC | | $0.9583 | /therm |
| LDAC | | $0 0336 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Winter Season
C&I - Low Annual Use, Low Winter Use
Rate G-51

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Base | Revenues | Base | Revenues | Revenues Base | Percent Base | | Revenues | | Revenues | Revenues | Percent |
| therm | Rate | Per therm | Rate | Per therm | Rate | Rate | Rate | Per therm | Rate | Per therm | Rate | Rate |
| 0 | $24.81 | NA | $50.00 | NA | $25.19 | 101.53% | $24.81 | NA | $50.00 | NA | $25.19 | 101.53% |
| 10 | 27.29 | 2.729 | 51.10 | 5.110 | 23.81 | 87.25% | 38.59 | 3.859 | 62.54 | 6.254 | 23.95 | 62.06% |
| 25 | 31.01 | 1.241 | 52.76 | 2.110 | 21.75 | 70.12% | 59.26 | 2.370 | 81.35 | 3.254 | 22.09 | 37.27% |
| 50 | 37.22 | 0.744 | 55.52 | 1.110 | 18.30 | 49.17% | 93.71 | 1.874 | 112.69 | 2.254 | 18.98 | 20.25% |
| 75 | 43.42 | 0.579 | 58.27 | 0.777 | 14.86 | 34.21% | 128.16 | 1.709 | 144.04 | 1.920 | 15.88 | 12.39% |
| 100 | 49.62 | 0.496 | 61.03 | 0.610 | 11.41 | 22.99% | 162.61 | 1.626 | 175.38 | 1.754 | 12.77 | 7.85% |
| 150 | 57.64 | 0.384 | 64.59 | 0.431 | 6.96 | 12.07% | 227.12 | 1.514 | 236.12 | 1.574 | 9.00 | 3.96% |
| 200 | 65.65 | 0.328 | 68.15 | 0.341 | 2.50 | 3.81% | 291.63 | 1.458 | 296.85 | 1.484 | 5.22 | 1.79% |
| 250 | 73.67 | 0.295 | 71.71 | 0.287 | (1.95) | -2.65% | 356.14 | 1.425 | 357.59 | 1.430 | 1.45 | 0.41% |
| 300 | 81.68 | 0.272 | 75.27 | 0.251 | (6.41) | -7.85% | 420.65 | 1.402 | 418.32 | 1.394 | (2.33) | -0.55% |
| 350 | 89.70 | 0.256 | 78.83 | 0.225 | (10.87) | -12.11% | 485.16 | 1.386 | 479.06 | 1.369 | (6.11) | -1.26% |
| 400 | 97.71 | 0.244 | 82.39 | 0.206 | (15.32) | -15.68% | 549.67 | 1.374 | 539.79 | 1.349 | (9.88) | -1.80% |
| 500 | 113.74 | 0.227 | 89.51 | 0.179 | (24.23) | -21.30% | 678.69 | 1.357 | 661.26 | 1.323 | (17.43) | -2.57% |
| 600 | 129.77 | 0.216 | 96.63 | 0.161 | (33.14) | -25.54% | 807.71 | 1.346 | 782.73 | 1.305 | (24.98) | -3.09% |
| 700 | 145.80 | 0.208 | 103.75 | 0.148 | (42.05) | -28.84% | 936.73 | 1.338 | 904.20 | 1.292 | (32.53) | -3.47% |
| 800 | 161.83 | 0.202 | 110.87 | 0.139 | (50.96) | -31.49% | 1,065.75 | 1.332 | 1,025.67 | 1.282 | (40.08) | -3.76% |
| 900 | 177.86 | 0.198 | 117.99 | 0.131 | (59.87) | -33.66% | 1,194.77 | 1.328 | 1,147.14 | 1.275 | (47.63) | -3.99% |
| 1,000 | 193.89 | 0.194 | 125.11 | 0.125 | (68.78) | -35.47% | 1,323.79 | 1.324 | 1,268.61 | 1.269 | (55.18) | -4.17% |
| 1,250 | 233.97 | 0.187 | 142.91 | 0.114 | (91.06) | -38.92% | 1,646.34 | 1.317 | 1,572.29 | 1.258 | (74.06) | -4.50% |
| 1,500 | 274.04 | 0.183 | 160.71 | 0.107 | (113.33) | -41.36% | 1,968.89 | 1.313 | 1,875.96 | 1.251 | (92.93) | -4.72% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 40 | 34.73 | 0.868 | 54.41 | 1.360 | 19.68 | 56.65% | 79.93 | 1.998 | 100.15 | 2.504 | 20.22 | 25.30% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 150 | 57.64 | 0.384 | 64.59 | 0.431 | 6.96 | 12.07% | 227.12 | 1.514 | 236.12 | 1.574 | 9.00 | 3.96% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 400 | 97.71 | 0.244 | 82.39 | 0.206 | (15.32) | -15.68% | 549.67 | 1.374 | 539.79 | 1.349 | (9.88) | -1.80% |

| Equivalent DRY Therm Present Rate | Block therm | G-51 Rate | |
|---|---|---|---|
| Customer Charge | - | $24.81 | /Customer |
| First | 100 | $0.2481 | /therm |
| Over | 100 | $0.1603 | /therm |
| TOTAL CGC & LDAC | | $1.1299 | /therm |
| CGC | | $1.1200 | |
| LDAC | | $0.0099 | |

| Proposed Rate | Block therm | G-51 Rate | |
|---|---|---|---|
| Customer Charge | - | $50.00 | /Customer |
| First | 100 | $0.1103 | /therm |
| Over | 100 | $0.0712 | /therm |
| TOTAL CGC & LDAC | | $1.1435 | /therm |
| CGC | | $1.1336 | /therm |
| LDAC | | $0.0099 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Summer Season
C&I - Low Annual Use, Low Winter Use
Rate G-51

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate | | Proposed Rate | | Difference | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Revenues | Percent | With CGC Revenues | | With CGC Revenues | | With CGC Revenues | |
| | Base | Revenues | Base | Revenues | Base | Base | | Revenues | | Revenues | Revenues | Percent |
| therm | Rate | Per therm | Rate | Per therm | Rate | Rate | Rate | Per therm | Rate | Per therm | Rate | Rate |
| 0 | $24.81 | NA | $50.00 | NA | $25.19 | 101.53% | $24.81 | NA | $50.00 | NA | $25.19 | 101.53% |
| 10 | 27.29 | 2.729 | 51.10 | 5.110 | 23.81 | 87.25% | 37.03 | 3.703 | 60.98 | 6.098 | 23.95 | 64.66% |
| 25 | 31.01 | 1.241 | 52.76 | 2.110 | 21.75 | 70.12% | 55.36 | 2.215 | 77.44 | 3.098 | 22.08 | 39.88% |
| 50 | 37.22 | 0.744 | 55.52 | 1.110 | 18.30 | 49.17% | 85.92 | 1.718 | 104.88 | 2.098 | 18.97 | 22.07% |
| 75 | 43.42 | 0.579 | 58.27 | 0.777 | 14.86 | 34.21% | 116.47 | 1.553 | 132.32 | 1.764 | 15.85 | 13.61% |
| 100 | 49.62 | 0.496 | 61.03 | 0.610 | 11.41 | 22.99% | 147.02 | 1.470 | 159.76 | 1.598 | 12.74 | 8.67% |
| 150 | 57.64 | 0.384 | 64.59 | 0.431 | 6.96 | 12.07% | 203.74 | 1.358 | 212.69 | 1.418 | 8.95 | 4.39% |
| 200 | 65.65 | 0.328 | 68.15 | 0.341 | 2.50 | 3.81% | 260.45 | 1.302 | 265.61 | 1.328 | 5.16 | 1.98% |
| 250 | 73.67 | 0.295 | 71.71 | 0.287 | (1.95) | -2.65% | 317.17 | 1.269 | 318.54 | 1.274 | 1.37 | 0.43% |
| 300 | 81.68 | 0.272 | 75.27 | 0.251 | (6.41) | -7.85% | 373.88 | 1.246 | 371.46 | 1.238 | (2.42) | -0.65% |
| 350 | 89.70 | 0.256 | 78.83 | 0.225 | (10.87) | -12.11% | 430.60 | 1.230 | 424.39 | 1.213 | (6.21) | -1.44% |
| 400 | 97.71 | 0.244 | 82.39 | 0.206 | (15.32) | -15.68% | 487.31 | 1.218 | 477.31 | 1.193 | (10.00) | -2.05% |
| 500 | 113.74 | 0.227 | 89.51 | 0.179 | (24.23) | -21.30% | 600.74 | 1.201 | 583.16 | 1.166 | (17.58) | -2.93% |
| 600 | 129.77 | 0.216 | 96.63 | 0.161 | (33.14) | -25.54% | 714.17 | 1.190 | 689.01 | 1.148 | (25.16) | -3.52% |
| 700 | 145.80 | 0.208 | 103.75 | 0.148 | (42.05) | -28.84% | 827.60 | 1.182 | 794.86 | 1.136 | (32.74) | -3.96% |
| 800 | 161.83 | 0.202 | 110.87 | 0.139 | (50.96) | -31.49% | 941.03 | 1.176 | 900.71 | 1.126 | (40.32) | -4.28% |
| 900 | 177.86 | 0.198 | 117.99 | 0.131 | (59.87) | -33.66% | 1,054.46 | 1.172 | 1,006.55 | 1.118 | (47.90) | -4.54% |
| 1,000 | 193.89 | 0.194 | 125.11 | 0.125 | (68.78) | -35.47% | 1,167.89 | 1.168 | 1,112.41 | 1.112 | (55.48) | -4.75% |
| 1,250 | 233.97 | 0.187 | 142.91 | 0.114 | (91.06) | -38.92% | 1,451.47 | 1.161 | 1,377.04 | 1.102 | (74.43) | -5.13% |
| 1,500 | 274.04 | 0.183 | 160.71 | 0.107 | (113.33) | -41.36% | 1,735.04 | 1.157 | 1,641.66 | 1.094 | (93.38) | -5.38% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 7 | 26.55 | 3.792 | 50.77 | 7.253 | 24.23 | 91.26% | 33.36 | 4.766 | 57.68 | 8.240 | 24.32 | 72.89% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 55 | 38.46 | 0.699 | 56.07 | 1.019 | 17.61 | 45.80% | 92.03 | 1.673 | 110.37 | 2.007 | 18.34 | 19.93% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 250 | 73.67 | 0.295 | 71.71 | 0.287 | (1.95) | -2.65% | 317.17 | 1.269 | 318.54 | 1.274 | 1.37 | 0.43% |

| Equivalent DRY Therm Present Rate | Block therm | G-51 Rate | |
|---|---|---|---|
| Customer Charge | - | $24.81 | /Customer |
| First | 100 | $0.2481 | /therm |
| Over | 100 | $0.1603 | /therm |
| TOTAL CGC & LDAC | | $0.9740 | /therm |
| CGC | | $0.9404 | |
| LDAC | | $0.0336 | |

| Proposed Rate | Block therm | G-51 Rate | |
|---|---|---|---|
| Customer Charge | - | $50.00 | /Customer |
| First | 100 | $0.1103 | /therm |
| Over | 100 | $0.0712 | /therm |
| TOTAL CGC & LDAC | | $0.9873 | /therm |
| CGC | | $0.9537 | /therm |
| LDAC | | $0.0336 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Winter Season
C&I - Medium Annual Use, Low Winter Use
Rate G-52

| Sales therm | Present Rate Base Rate | Present Rate Revenues Per therm | Proposed Rate Base Rate | Proposed Rate Revenues Per therm | Difference Revenues Base Rate | Difference Percent Base Rate | Present Rate With CGC Revenues Rate | Present Rate With CGC Revenues Revenues Per therm | Proposed Rate With CGC Revenues Rate | Proposed Rate With CGC Revenues Revenues Per therm | Difference With CGC Revenues Revenues Rate | Difference With CGC Revenues Percent Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | $69.29 | NA | $140.00 | NA | $70.71 | 102.05% | $69.29 | NA | $140.00 | NA | $70.71 | 102.05% |
| 10 | 70.99 | 7.099 | 141.30 | 14.130 | 70.30 | 99.02% | 82.29 | 8.229 | 152.73 | 15.273 | 70.44 | 85.59% |
| 25 | 73.55 | 2.942 | 143.24 | 5.730 | 69.69 | 94.75% | 101.80 | 4.072 | 171.83 | 6.873 | 70.03 | 68.79% |
| 50 | 77.81 | 1.556 | 146.48 | 2.930 | 68.67 | 88.25% | 134.31 | 2.686 | 203.66 | 4.073 | 69.35 | 51.63% |
| 75 | 82.07 | 1.094 | 149.71 | 1.996 | 67.64 | 82.42% | 166.81 | 2.224 | 235.48 | 3.140 | 68.66 | 41.16% |
| 100 | 86.33 | 0.863 | 152.95 | 1.530 | 66.62 | 77.17% | 199.32 | 1.993 | 267.30 | 2.673 | 67.98 | 34.11% |
| 150 | 94.85 | 0.632 | 159.43 | 1.063 | 64.58 | 68.08% | 264.34 | 1.762 | 330.95 | 2.206 | 66.62 | 25.20% |
| 200 | 103.37 | 0.517 | 165.90 | 0.830 | 62.53 | 60.49% | 329.35 | 1.647 | 394.60 | 1.973 | 65.25 | 19.81% |
| 250 | 111.89 | 0.448 | 172.38 | 0.690 | 60.49 | 54.06% | 394.37 | 1.577 | 458.25 | 1.833 | 63.89 | 16.20% |
| 300 | 120.41 | 0.401 | 178.85 | 0.596 | 58.44 | 48.53% | 459.38 | 1.531 | 521.90 | 1.740 | 62.52 | 13.61% |
| 350 | 128.93 | 0.368 | 185.33 | 0.530 | 56.40 | 43.74% | 524.40 | 1.498 | 585.55 | 1.673 | 61.16 | 11.66% |
| 400 | 137.45 | 0.344 | 191.80 | 0.480 | 54.35 | 39.54% | 589.41 | 1.474 | 649.20 | 1.623 | 59.79 | 10.14% |
| 500 | 154.49 | 0.309 | 204.75 | 0.410 | 50.26 | 32.53% | 719.44 | 1.439 | 776.50 | 1.553 | 57.06 | 7.93% |
| 750 | 197.09 | 0.263 | 237.13 | 0.316 | 40.04 | 20.31% | 1,044.52 | 1.393 | 1,094.75 | 1.460 | 50.23 | 4.81% |
| 1,000 | 239.69 | 0.240 | 269.50 | 0.270 | 29.81 | 12.44% | 1,369.59 | 1.370 | 1,413.00 | 1.413 | 43.41 | 3.17% |
| 1,500 | 297.54 | 0.198 | 313.45 | 0.209 | 15.91 | 5.35% | 1,992.39 | 1.328 | 2,028.70 | 1.352 | 36.31 | 1.82% |
| 2,000 | 355.39 | 0.178 | 357.40 | 0.179 | 2.01 | 0.57% | 2,615.19 | 1.308 | 2,644.40 | 1.322 | 29.21 | 1.12% |
| 3,000 | 471.09 | 0.157 | 445.30 | 0.148 | (25.79) | -5.47% | 3,860.79 | 1.287 | 3,875.80 | 1.292 | 15.01 | 0.39% |
| 4,000 | 586.79 | 0.147 | 533.20 | 0.133 | (53.59) | -9.13% | 5,106.39 | 1.277 | 5,107.20 | 1.277 | 0.81 | 0.02% |
| 5,000 | 702.49 | 0.140 | 621.10 | 0.124 | (81.39) | -11.59% | 6,351.99 | 1.270 | 6,338.60 | 1.268 | (13.39) | -0.21% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 1,000 | 239.69 | 0.240 | 269.50 | 0.270 | 29.81 | 12.44% | 1,369.59 | 1.370 | 1,413.00 | 1.413 | 43.41 | 3.17% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 1,500 | 297.54 | 0.198 | 313.45 | 0.209 | 15.91 | 5.35% | 1,992.39 | 1.328 | 2,028.70 | 1.352 | 36.31 | 1.82% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 2,500 | 413.24 | 0.165 | 401.35 | 0.161 | (11.89) | -2.88% | 3,237.99 | 1.295 | 3,260.10 | 1.304 | 22.11 | 0.68% |

| Equivalent DRY Therm Present Rate | Block therm | G-52 Rate | |
|---|---|---|---|
| Customer Charge | - | $69.29 | /Customer |
| First | 1,000 | $0.1704 | /therm |
| Over | 1,000 | $0.1157 | /therm |
| TOTAL CGC & LDAC | | $1.1299 | /therm |
| CGC | | $1.1200 | |
| LDAC | | $0.0099 | |

| Proposed Rate | Block therm | G-52 Rate | |
|---|---|---|---|
| Customer Charge | - | $140.00 | /Customer |
| First | 1,000 | $0.1295 | /therm |
| Over | 1,000 | $0.0879 | /therm |
| TOTAL CGC & LDAC | | $1.1435 | /therm |
| CGC | | $1.1336 | /therm |
| LDAC | | $0.0099 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Summer Season
C&I - Medium Annual Use, Low Winter Use
Rate G-52

| Sales therm | Present Rate Base Rate | Present Rate Revenues Per therm | Proposed Rate Base Rate | Proposed Rate Revenues Per therm | Difference Revenues Base Rate | Difference Percent Base Rate | Present Rate With CGC Revenues Rate | Present Rate With CGC Revenues Revenues Per therm | Proposed Rate With CGC Revenues Rate | Proposed Rate With CGC Revenues Revenues Per therm | Difference With CGC Revenues Revenues Rate | Difference With CGC Revenues Percent Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | $69.29 | NA | $140.00 | NA | $70.71 | 102.05% | $69.29 | NA | $140.00 | NA | $70.71 | 102.05% |
| 10 | 70.54 | 7.054 | 140.95 | 14.095 | 70.41 | 99.81% | 80.26 | 8.026 | 150.83 | 15.083 | 70.54 | 87.87% |
| 25 | 72.42 | 2.897 | 142.38 | 5.695 | 69.96 | 96.60% | 96.77 | 3.871 | 167.06 | 6.683 | 70.29 | 72.63% |
| 50 | 75.56 | 1.511 | 144.76 | 2.895 | 69.21 | 91.60% | 124.26 | 2.485 | 194.13 | 3.883 | 69.87 | 56.23% |
| 75 | 78.69 | 1.049 | 147.14 | 1.962 | 68.45 | 86.99% | 151.74 | 2.023 | 221.19 | 2.949 | 69.45 | 45.77% |
| 100 | 81.82 | 0.818 | 149.52 | 1.495 | 67.70 | 82.74% | 179.22 | 1.792 | 248.25 | 2.483 | 69.03 | 38.52% |
| 150 | 88.09 | 0.587 | 154.28 | 1.029 | 66.20 | 75.15% | 234.19 | 1.561 | 302.38 | 2.016 | 68.19 | 29.12% |
| 200 | 94.35 | 0.472 | 159.04 | 0.795 | 64.69 | 68.56% | 289.15 | 1.446 | 356.50 | 1.783 | 67.35 | 23.29% |
| 250 | 100.62 | 0.402 | 163.80 | 0.655 | 63.19 | 62.80% | 344.12 | 1.376 | 410.63 | 1.643 | 66.51 | 19.33% |
| 300 | 106.88 | 0.356 | 168.56 | 0.562 | 61.68 | 57.71% | 399.08 | 1.330 | 464.75 | 1.549 | 65.67 | 16.46% |
| 350 | 113.15 | 0.323 | 173.32 | 0.495 | 60.18 | 53.18% | 454.05 | 1.297 | 518.88 | 1.483 | 64.83 | 14.28% |
| 400 | 119.41 | 0.299 | 178.08 | 0.445 | 58.67 | 49.13% | 509.01 | 1.273 | 573.00 | 1.433 | 63.99 | 12.57% |
| 500 | 131.94 | 0.264 | 187.60 | 0.375 | 55.66 | 42.19% | 618.94 | 1.238 | 681.25 | 1.363 | 62.31 | 10.07% |
| 750 | 163.27 | 0.218 | 211.40 | 0.282 | 48.14 | 29.48% | 893.77 | 1.192 | 951.88 | 1.269 | 58.11 | 6.50% |
| 1,000 | 194.59 | 0.195 | 235.20 | 0.235 | 40.61 | 20.87% | 1,168.59 | 1.169 | 1,222.50 | 1.223 | 53.91 | 4.61% |
| 1,500 | 230.64 | 0.154 | 262.60 | 0.175 | 31.96 | 13.86% | 1,691.64 | 1.128 | 1,743.55 | 1.162 | 51.91 | 3.07% |
| 2,000 | 266.69 | 0.133 | 290.00 | 0.145 | 23.31 | 8.74% | 2,214.69 | 1.107 | 2,264.60 | 1.132 | 49.91 | 2.25% |
| 3,000 | 338.79 | 0.113 | 344.80 | 0.115 | 6.01 | 1.77% | 3,260.79 | 1.087 | 3,306.70 | 1.102 | 45.91 | 1.41% |
| 4,000 | 410.69 | 0.103 | 399.60 | 0.100 | (11.29) | -2.75% | 4,305.89 | 1.077 | 4,348.80 | 1.087 | 41.91 | 0.97% |
| 5,000 | 482.99 | 0.097 | 454.40 | 0.091 | (28.59) | -5.92% | 5,352.99 | 1.071 | 5,390.90 | 1.078 | 37.91 | 0.71% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 700 | 157.00 | 0.224 | 206.64 | 0.295 | 49.64 | 31.62% | 838.80 | 1.198 | 897.75 | 1.283 | 58.95 | 7.03% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 1,040 | 197.47 | 0.190 | 237.39 | 0.228 | 39.92 | 20.21% | 1,210.43 | 1.164 | 1,264.18 | 1.216 | 53.75 | 4.44% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 1,500 | 230.64 | 0.154 | 262.60 | 0.175 | 31.96 | 13.86% | 1,691.64 | 1.128 | 1,743.55 | 1.162 | 51.91 | 3.07% |

**Equivalent DRY Therm Present Rate — G-52**

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $69.29 | /Customer |
| First | 1,000 | $0.1253 | /therm |
| Over | 1,000 | $0.0721 | /therm |
| TOTAL CGC & LDAC | | $0.9740 | /therm |
| CGC | | $0.9404 | |
| LDAC | | $0.0336 | |

**Proposed Rate — G-52**

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $140.00 | /Customer |
| First | 1,000 | $0.0952 | /therm |
| Over | 1,000 | $0.0548 | /therm |
| TOTAL CGC & LDAC | | $0.9873 | /therm |
| CGC | | $0.9537 | /therm |
| LDAC | | $0.0336 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Winter Season
C&I - High Annual Use, Load Factor Less Than 90%
Rate G-53

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% |
| 2,500 | 563.75 | 0.226 | 879.00 | 0.352 | 315.25 | 55.92% | 3,388.50 | 1.355 | 3,737.75 | 1.495 | 349.25 | 10.31% |
| 5,000 | 827.50 | 0.166 | 1,158.00 | 0.232 | 330.50 | 39.94% | 6,477.00 | 1.295 | 6,875.50 | 1.375 | 398.50 | 6.15% |
| 7,500 | 1,091.25 | 0.146 | 1,437.00 | 0.192 | 345.75 | 31.68% | 9,565.50 | 1.275 | 10,013.25 | 1.335 | 447.75 | 4.68% |
| 10,000 | 1,355.00 | 0.136 | 1,716.00 | 0.172 | 361.00 | 26.64% | 12,654.00 | 1.265 | 13,151.00 | 1.315 | 497.00 | 3.93% |
| 12,500 | 1,618.75 | 0.130 | 1,995.00 | 0.160 | 376.25 | 23.24% | 15,742.50 | 1.259 | 16,288.75 | 1.303 | 546.25 | 3.47% |
| 15,000 | 1,882.50 | 0.126 | 2,274.00 | 0.152 | 391.50 | 20.80% | 18,831.00 | 1.255 | 19,426.50 | 1.295 | 595.50 | 3.16% |
| 20,000 | 2,410.00 | 0.121 | 2,832.00 | 0.142 | 422.00 | 17.51% | 25,008.00 | 1.250 | 25,702.00 | 1.285 | 694.00 | 2.78% |
| 25,000 | 2,937.50 | 0.118 | 3,390.00 | 0.136 | 452.50 | 15.40% | 31,185.00 | 1.247 | 31,977.50 | 1.279 | 792.50 | 2.54% |
| 30,000 | 3,465.00 | 0.116 | 3,948.00 | 0.132 | 483.00 | 13.94% | 37,362.00 | 1.245 | 38,253.00 | 1.275 | 891.00 | 2.38% |
| 35,000 | 3,992.50 | 0.114 | 4,506.00 | 0.129 | 513.50 | 12.86% | 43,539.00 | 1.244 | 44,528.50 | 1.272 | 989.50 | 2.27% |
| 40,000 | 4,520.00 | 0.113 | 5,064.00 | 0.127 | 544.00 | 12.04% | 49,716.00 | 1.243 | 50,804.00 | 1.270 | 1,088.00 | 2.19% |
| 45,000 | 5,047.50 | 0.112 | 5,622.00 | 0.125 | 574.50 | 11.38% | 55,893.00 | 1.242 | 57,079.50 | 1.268 | 1,186.50 | 2.12% |
| 50,000 | 5,575.00 | 0.112 | 6,180.00 | 0.124 | 605.00 | 10.85% | 62,070.00 | 1.241 | 63,355.00 | 1.267 | 1,285.00 | 2.07% |
| 55,000 | 6,102.50 | 0.111 | 6,738.00 | 0.123 | 635.50 | 10.41% | 68,247.00 | 1.241 | 69,630.50 | 1.266 | 1,383.50 | 2.03% |
| 60,000 | 6,630.00 | 0.111 | 7,296.00 | 0.122 | 666.00 | 10.05% | 74,424.00 | 1.240 | 75,906.00 | 1.265 | 1,482.00 | 1.99% |
| 75,000 | 8,212.50 | 0.110 | 8,970.00 | 0.120 | 757.50 | 9.22% | 92,955.00 | 1.239 | 94,732.50 | 1.263 | 1,777.50 | 1.91% |
| 100,000 | 10,850.00 | 0.109 | 11,760.00 | 0.118 | 910.00 | 8.39% | 123,840.00 | 1.238 | 126,110.00 | 1.261 | 2,270.00 | 1.83% |
| 150,000 | 16,125.00 | 0.108 | 17,340.00 | 0.116 | 1,215.00 | 7.53% | 185,610.00 | 1.237 | 188,865.00 | 1.259 | 3,255.00 | 1.75% |
| 200,000 | 21,400.00 | 0.107 | 22,920.00 | 0.115 | 1,520.00 | 7.10% | 247,380.00 | 1.237 | 251,620.00 | 1.258 | 4,240.00 | 1.71% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 8,000 | 1,144.00 | 0.143 | 1,492.80 | 0.187 | 348.80 | 30.49% | 10,183.20 | 1.273 | 10,640.60 | 1.330 | 457.60 | 4.49% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 15,000 | 1,882.50 | 0.126 | 2,274.00 | 0.152 | 391.50 | 20.80% | 18,831.00 | 1.255 | 19,426.50 | 1.295 | 595.50 | 3.16% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 25,000 | 2,937.50 | 0.118 | 3,390.00 | 0.136 | 452.50 | 15.40% | 31,185.00 | 1.247 | 31,977.50 | 1.279 | 792.50 | 2.54% |

| Equivalent DRY Therm Present Rate | Block therm | G-53 Rate | |
|---|---|---|---|
| Customer Charge | - | $300.00 | /Customer |
| First | - | $0.1055 | /therm |
| Over | - | $0.1055 | /therm |
| TOTAL CGC & LDAC | | $1.1299 | /therm |
| CGC | | $1.1200 | |
| LDAC | | $0.0099 | |

| Proposed Rate | Block therm | G-53 Rate | |
|---|---|---|---|
| Customer Charge | - | $600.00 | /Customer |
| First | - | $0.1116 | /therm |
| Over | | $0.1116 | /therm |
| TOTAL CGC & LDAC | | $1.1435 | /therm |
| CGC | | $1.1336 | /therm |
| LDAC | | $0.0099 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Summer Season
C&I - High Annual Use, Load Factor Less Than 90%
Rate G-53

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% |
| 2,500 | 426.25 | 0.171 | 733.50 | 0.293 | 307.25 | 72.06% | 2,861.25 | 1.145 | 3,201.75 | 1.281 | 340.50 | 11.90% |
| 5,000 | 552.50 | 0.111 | 867.00 | 0.173 | 314.50 | 56.92% | 5,422.50 | 1.085 | 5,803.50 | 1.161 | 381.00 | 7.03% |
| 7,500 | 678.75 | 0.091 | 1,000.50 | 0.133 | 321.75 | 47.40% | 7,983.75 | 1.065 | 8,405.25 | 1.121 | 421.50 | 5.28% |
| 10,000 | 805.00 | 0.081 | 1,134.00 | 0.113 | 329.00 | 40.87% | 10,545.00 | 1.055 | 11,007.00 | 1.101 | 462.00 | 4.38% |
| 12,500 | 931.25 | 0.075 | 1,267.50 | 0.101 | 336.25 | 36.11% | 13,106.25 | 1.049 | 13,608.75 | 1.089 | 502.50 | 3.83% |
| 15,000 | 1,057.50 | 0.071 | 1,401.00 | 0.093 | 343.50 | 32.48% | 15,667.50 | 1.045 | 16,210.50 | 1.081 | 543.00 | 3.47% |
| 20,000 | 1,310.00 | 0.066 | 1,668.00 | 0.083 | 358.00 | 27.33% | 20,790.00 | 1.040 | 21,414.00 | 1.071 | 624.00 | 3.00% |
| 25,000 | 1,562.50 | 0.063 | 1,935.00 | 0.077 | 372.50 | 23.84% | 25,912.50 | 1.037 | 26,617.50 | 1.065 | 705.00 | 2.72% |
| 30,000 | 1,815.00 | 0.061 | 2,202.00 | 0.073 | 387.00 | 21.32% | 31,035.00 | 1.035 | 31,821.00 | 1.061 | 786.00 | 2.53% |
| 35,000 | 2,067.50 | 0.059 | 2,469.00 | 0.071 | 401.50 | 19.42% | 36,157.50 | 1.033 | 37,024.50 | 1.058 | 867.00 | 2.40% |
| 40,000 | 2,320.00 | 0.058 | 2,736.00 | 0.068 | 416.00 | 17.93% | 41,280.00 | 1.032 | 42,228.00 | 1.056 | 948.00 | 2.30% |
| 45,000 | 2,572.50 | 0.057 | 3,003.00 | 0.067 | 430.50 | 16.73% | 46,402.50 | 1.031 | 47,431.50 | 1.054 | 1,029.00 | 2.22% |
| 50,000 | 2,825.00 | 0.057 | 3,270.00 | 0.065 | 445.00 | 15.75% | 51,525.00 | 1.031 | 52,635.00 | 1.053 | 1,110.00 | 2.15% |
| 55,000 | 3,077.50 | 0.056 | 3,537.00 | 0.064 | 459.50 | 14.93% | 56,647.50 | 1.030 | 57,838.50 | 1.052 | 1,191.00 | 2.10% |
| 60,000 | 3,330.00 | 0.056 | 3,804.00 | 0.063 | 474.00 | 14.23% | 61,770.00 | 1.030 | 63,042.00 | 1.051 | 1,272.00 | 2.06% |
| 75,000 | 4,087.50 | 0.055 | 4,605.00 | 0.061 | 517.50 | 12.66% | 77,137.50 | 1.029 | 78,652.50 | 1.049 | 1,515.00 | 1.96% |
| 100,000 | 5,350.00 | 0.054 | 5,940.00 | 0.059 | 590.00 | 11.03% | 102,750.00 | 1.028 | 104,670.00 | 1.047 | 1,920.00 | 1.87% |
| 150,000 | 7,875.00 | 0.053 | 8,610.00 | 0.057 | 735.00 | 9.33% | 153,975.00 | 1.027 | 156,705.00 | 1.045 | 2,730.00 | 1.77% |
| 200,000 | 10,400.00 | 0.052 | 11,280.00 | 0.056 | 880.00 | 8.46% | 205,200.00 | 1.026 | 208,740.00 | 1.044 | 3,540.00 | 1.73% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 2,570 | 429.79 | 0.167 | 737.24 | 0.287 | 307.45 | 71.54% | 2,932.97 | 1.141 | 3,274.60 | 1.274 | 341.63 | 11.65% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 10,000 | 805.00 | 0.081 | 1,134.00 | 0.113 | 329.00 | 40.87% | 10,545.00 | 1.055 | 11,007.00 | 1.101 | 462.00 | 4.38% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 20,000 | 1,310.00 | 0.066 | 1,668.00 | 0.083 | 358.00 | 27.33% | 20,790.00 | 1.040 | 21,414.00 | 1.071 | 624.00 | 3.00% |

Equivalent DRY Therm Present Rate G-53

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $300.00 | /Customer |
| First | - | $0.0505 | /therm |
| Over | - | $0.0505 | /therm |
| TOTAL CGC & LDAC | | $0.9740 | /therm |
| CGC | | $0.9404 | |
| LDAC | | $0.0336 | |

Proposed Rate G-53

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $600.00 | /Customer |
| First | - | $0.0534 | /therm |
| Over | - | $0.0534 | /therm |
| TOTAL CGC & LDAC | | $0.9873 | /therm |
| CGC | | $0.9537 | /therm |
| LDAC | | $0.0336 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Winter Season
C&I - High Annual Use, Load Factor Less Than 110%
Rate G-54

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Base | Revenues | Base | Revenues | Revenues Base | Percent Base | | Revenues | | Revenues | Revenues | Percent |
| therm | Rate | Per therm | Rate | Per therm | Rate | Rate | Rate | Per therm | Rate | Per therm | Rate | Rate |
| 0 | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% |
| 2,500 | 496.25 | 0.199 | 795.25 | 0.318 | 299.00 | 60.25% | 3,321.00 | 1.328 | 3,654.00 | 1.462 | 333.00 | 10.03% |
| 5,000 | 692.50 | 0.139 | 990.50 | 0.198 | 298.00 | 43.03% | 6,342.00 | 1.268 | 6,708.00 | 1.342 | 366.00 | 5.77% |
| 7,500 | 888.75 | 0.119 | 1,185.75 | 0.158 | 297.00 | 33.42% | 9,363.00 | 1.248 | 9,762.00 | 1.302 | 399.00 | 4.26% |
| 10,000 | 1,085.00 | 0.109 | 1,381.00 | 0.138 | 296.00 | 27.28% | 12,384.00 | 1.238 | 12,816.00 | 1.282 | 432.00 | 3.49% |
| 12,500 | 1,281.25 | 0.103 | 1,576.25 | 0.126 | 295.00 | 23.02% | 15,405.00 | 1.232 | 15,870.00 | 1.270 | 465.00 | 3.02% |
| 15,000 | 1,477.50 | 0.099 | 1,771.50 | 0.118 | 294.00 | 19.90% | 18,426.00 | 1.228 | 18,924.00 | 1.262 | 498.00 | 2.70% |
| 20,000 | 1,870.00 | 0.094 | 2,162.00 | 0.108 | 292.00 | 15.61% | 24,468.00 | 1.223 | 25,032.00 | 1.252 | 564.00 | 2.31% |
| 25,000 | 2,262.50 | 0.091 | 2,552.50 | 0.102 | 290.00 | 12.82% | 30,510.00 | 1.220 | 31,140.00 | 1.246 | 630.00 | 2.06% |
| 30,000 | 2,655.00 | 0.089 | 2,943.00 | 0.098 | 288.00 | 10.85% | 36,552.00 | 1.218 | 37,248.00 | 1.242 | 696.00 | 1.90% |
| 35,000 | 3,047.50 | 0.087 | 3,333.50 | 0.095 | 286.00 | 9.38% | 42,594.00 | 1.217 | 43,356.00 | 1.239 | 762.00 | 1.79% |
| 40,000 | 3,440.00 | 0.086 | 3,724.00 | 0.093 | 284.00 | 8.26% | 48,636.00 | 1.216 | 49,464.00 | 1.237 | 828.00 | 1.70% |
| 45,000 | 3,832.50 | 0.085 | 4,114.50 | 0.091 | 282.00 | 7.36% | 54,678.00 | 1.215 | 55,572.00 | 1.235 | 894.00 | 1.64% |
| 50,000 | 4,225.00 | 0.085 | 4,505.00 | 0.090 | 280.00 | 6.63% | 60,720.00 | 1.214 | 61,680.00 | 1.234 | 960.00 | 1.58% |
| 55,000 | 4,617.50 | 0.084 | 4,895.50 | 0.089 | 278.00 | 6.02% | 66,762.00 | 1.214 | 67,788.00 | 1.233 | 1,026.00 | 1.54% |
| 60,000 | 5,010.00 | 0.084 | 5,286.00 | 0.088 | 276.00 | 5.51% | 72,804.00 | 1.213 | 73,896.00 | 1.232 | 1,092.00 | 1.50% |
| 75,000 | 6,187.50 | 0.083 | 6,457.50 | 0.086 | 270.00 | 4.36% | 90,930.00 | 1.212 | 92,220.00 | 1.230 | 1,290.00 | 1.42% |
| 100,000 | 8,150.00 | 0.082 | 8,410.00 | 0.084 | 260.00 | 3.19% | 121,140.00 | 1.211 | 122,760.00 | 1.228 | 1,620.00 | 1.34% |
| 150,000 | 12,075.00 | 0.081 | 12,315.00 | 0.082 | 240.00 | 1.99% | 181,560.00 | 1.210 | 183,840.00 | 1.226 | 2,280.00 | 1.26% |
| 200,000 | 16,000.00 | 0.080 | 16,220.00 | 0.081 | 220.00 | 1.38% | 241,980.00 | 1.210 | 244,920.00 | 1.225 | 2,940.00 | 1.21% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 15,000 | 1,477.50 | 0.099 | 1,771.50 | 0.118 | 294.00 | 19.90% | 18,426.00 | 1.226 | 18,924.00 | 1.262 | 498.00 | 2.70% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 20,000 | 1,870.00 | 0.094 | 2,162.00 | 0.108 | 292.00 | 15.61% | 24,468.00 | 1.223 | 25,032.00 | 1.252 | 564.00 | 2.31% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 25,000 | 2,262.50 | 0.091 | 2,552.50 | 0.102 | 290.00 | 12.62% | 30,510.00 | 1.220 | 31,140.00 | 1.246 | 630.00 | 2.06% |

| Equivalent DRY Therm Present Rate | Block therm | G-54 Rate | |
|---|---|---|---|
| Customer Charge | - | $300.00 | /Customer |
| First | - | $0.0785 | /therm |
| Over | - | $0.0785 | /therm |
| TOTAL CGC & LDAC | | $1.1299 | /therm |
| CGC | | $1.1200 | |
| LDAC | | $0.0099 | |

| Proposed Rate | Block therm | G-54 Rate | |
|---|---|---|---|
| Customer Charge | - | $600.00 | /Customer |
| First | - | $0.0781 | /therm |
| Over | - | $0.0781 | /therm |
| TOTAL CGC & LDAC | | $1.1435 | /therm |
| CGC | | $1.1336 | /therm |
| LDAC | | $0.0099 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Summer Season
C&I - High Annual Use, Load Factor Less Than 110%
Rate G-54

| Sales therm | Present Rate Base Rate | Present Rate Revenues Per therm | Proposed Rate Base Rate | Proposed Rate Revenues Per therm | Difference Revenues Base Rate | Difference Percent Base Rate | Present Rate With CGC Revenues Rate | Present Rate With CGC Revenues Revenues Per therm | Proposed Rate With CGC Revenues Rate | Proposed Rate With CGC Revenues Revenues Per therm | Difference With CGC Revenues Revenues Rate | Difference With CGC Revenues Percent Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% |
| 2,500 | 400.75 | 0.160 | 700.25 | 0.280 | 299.50 | 74.73% | 2,835.75 | 1.134 | 3,166.50 | 1.267 | 332.75 | 11.73% |
| 5,000 | 501.50 | 0.100 | 800.50 | 0.160 | 299.00 | 59.62% | 5,371.50 | 1.074 | 5,737.00 | 1.147 | 365.50 | 6.80% |
| 7,500 | 602.25 | 0.080 | 900.75 | 0.120 | 298.50 | 49.56% | 7,907.25 | 1.054 | 8,305.50 | 1.107 | 398.25 | 5.04% |
| 10,000 | 703.00 | 0.070 | 1,001.00 | 0.100 | 298.00 | 42.39% | 10,443.00 | 1.044 | 10,874.00 | 1.087 | 431.00 | 4.13% |
| 12,500 | 803.75 | 0.064 | 1,101.25 | 0.088 | 297.50 | 37.01% | 12,978.75 | 1.038 | 13,442.50 | 1.075 | 463.75 | 3.57% |
| 15,000 | 904.50 | 0.060 | 1,201.50 | 0.080 | 297.00 | 32.84% | 15,514.50 | 1.034 | 16,011.00 | 1.067 | 496.50 | 3.20% |
| 20,000 | 1,106.00 | 0.055 | 1,402.00 | 0.070 | 296.00 | 26.76% | 20,586.00 | 1.029 | 21,148.00 | 1.057 | 562.00 | 2.73% |
| 25,000 | 1,307.50 | 0.052 | 1,602.50 | 0.064 | 295.00 | 22.56% | 25,657.50 | 1.026 | 26,285.00 | 1.051 | 627.50 | 2.45% |
| 30,000 | 1,509.00 | 0.050 | 1,803.00 | 0.060 | 294.00 | 19.48% | 30,729.00 | 1.024 | 31,422.00 | 1.047 | 693.00 | 2.26% |
| 35,000 | 1,710.50 | 0.049 | 2,003.50 | 0.057 | 293.00 | 17.13% | 35,800.50 | 1.023 | 36,559.00 | 1.045 | 758.50 | 2.12% |
| 40,000 | 1,912.00 | 0.048 | 2,204.00 | 0.055 | 292.00 | 15.27% | 40,872.00 | 1.022 | 41,696.00 | 1.042 | 824.00 | 2.02% |
| 45,000 | 2,113.50 | 0.047 | 2,404.50 | 0.053 | 291.00 | 13.77% | 45,943.50 | 1.021 | 46,833.00 | 1.041 | 889.50 | 1.94% |
| 50,000 | 2,315.00 | 0.046 | 2,605.00 | 0.052 | 290.00 | 12.53% | 51,015.00 | 1.020 | 51,970.00 | 1.039 | 955.00 | 1.87% |
| 55,000 | 2,516.50 | 0.046 | 2,805.50 | 0.051 | 289.00 | 11.48% | 56,086.50 | 1.020 | 57,107.00 | 1.038 | 1,020.50 | 1.82% |
| 60,000 | 2,718.00 | 0.045 | 3,006.00 | 0.050 | 288.00 | 10.60% | 61,158.00 | 1.019 | 62,244.00 | 1.037 | 1,086.00 | 1.78% |
| 75,000 | 3,322.50 | 0.044 | 3,607.50 | 0.048 | 285.00 | 8.58% | 76,372.50 | 1.018 | 77,655.00 | 1.035 | 1,282.50 | 1.68% |
| 100,000 | 4,330.00 | 0.043 | 4,610.00 | 0.046 | 280.00 | 6.47% | 101,730.00 | 1.017 | 103,340.00 | 1.033 | 1,610.00 | 1.58% |
| 150,000 | 6,345.00 | 0.042 | 6,615.00 | 0.044 | 270.00 | 4.28% | 152,445.00 | 1.016 | 154,710.00 | 1.031 | 2,265.00 | 1.49% |
| 200,000 | 8,360.00 | 0.042 | 8,620.00 | 0.043 | 260.00 | 3.11% | 203,160.00 | 1.016 | 206,080.00 | 1.030 | 2,920.00 | 1.44% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 20,000 | 1,106.00 | 0.055 | 1,402.00 | 0.070 | 296.00 | 26.76% | 20,586.00 | 1.029 | 21,148.00 | 1.057 | 562.00 | 2.73% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 20,000 | 1,106.00 | 0.055 | 1,402.00 | 0.070 | 296.00 | 26.76% | 20,586.00 | 1.029 | 21,148.00 | 1.057 | 562.00 | 2.73% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 25,000 | 1,307.50 | 0.052 | 1,602.50 | 0.064 | 295.00 | 22.56% | 25,657.50 | 1.026 | 26,285.00 | 1.051 | 627.50 | 2.45% |

Equivalent DRY Therm Present Rate G-54

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $300.00 | /Customer |
| First | - | $0.0403 | /therm |
| Over | - | $0.0403 | /therm |
| TOTAL CGC & LDAC | | $0.9740 | /therm |
| CGC | | $0.9404 | |
| LDAC | | $0.0336 | |

Proposed Rate G-54

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $600.00 | /Customer |
| First | - | $0.0401 | /therm |
| Over | - | $0.0401 | /therm |
| TOTAL CGC & LDAC | | $0.9873 | /therm |
| CGC | | $0.9537 | /therm |
| LDAC | | $0.0336 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms)

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Winter Season
C&I - High Annual Use, Load Factor Greater Than 110%
Rate G-63

| Sales therm | Present Rate Base Rate | Present Rate Revenues Per therm | Proposed Rate Base Rate | Proposed Rate Revenues Per therm | Difference Revenues Base Rate | Difference Percent Base Rate | Present Rate With CGC Revenues Rate | Present Rate With CGC Revenues Revenues Per therm | Proposed Rate With CGC Revenues Rate | Proposed Rate With CGC Revenues Revenues Per therm | Difference With CGC Revenues Revenues Rate | Difference With CGC Revenues Percent Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% |
| 2,500 | 384.75 | 0.154 | 691.25 | 0.277 | 306.50 | 79.66% | 3,209.50 | 1.284 | 3,550.00 | 1.420 | 340.50 | 10.61% |
| 5,000 | 469.50 | 0.094 | 782.50 | 0.157 | 313.00 | 66.67% | 6,119.00 | 1.224 | 6,500.00 | 1.300 | 381.00 | 6.23% |
| 7,500 | 554.25 | 0.074 | 873.75 | 0.117 | 319.50 | 57.65% | 9,028.50 | 1.204 | 9,450.00 | 1.260 | 421.50 | 4.67% |
| 10,000 | 639.00 | 0.064 | 965.00 | 0.097 | 326.00 | 51.02% | 11,938.00 | 1.194 | 12,400.00 | 1.240 | 462.00 | 3.87% |
| 12,500 | 723.75 | 0.058 | 1,056.25 | 0.085 | 332.50 | 45.94% | 14,847.50 | 1.188 | 15,350.00 | 1.228 | 502.50 | 3.38% |
| 15,000 | 808.50 | 0.054 | 1,147.50 | 0.077 | 339.00 | 41.93% | 17,757.00 | 1.184 | 18,300.00 | 1.220 | 543.00 | 3.06% |
| 20,000 | 978.00 | 0.049 | 1,330.00 | 0.067 | 352.00 | 35.99% | 23,576.00 | 1.179 | 24,200.00 | 1.210 | 624.00 | 2.65% |
| 25,000 | 1,147.50 | 0.046 | 1,512.50 | 0.061 | 365.00 | 31.81% | 29,395.00 | 1.176 | 30,100.00 | 1.204 | 705.00 | 2.40% |
| 30,000 | 1,317.00 | 0.044 | 1,695.00 | 0.057 | 378.00 | 28.70% | 35,214.00 | 1.174 | 36,000.00 | 1.200 | 786.00 | 2.23% |
| 35,000 | 1,486.50 | 0.042 | 1,877.50 | 0.054 | 391.00 | 26.30% | 41,033.00 | 1.172 | 41,900.00 | 1.197 | 867.00 | 2.11% |
| 40,000 | 1,656.00 | 0.041 | 2,060.00 | 0.052 | 404.00 | 24.40% | 46,852.00 | 1.171 | 47,800.00 | 1.195 | 948.00 | 2.02% |
| 45,000 | 1,825.50 | 0.041 | 2,242.50 | 0.050 | 417.00 | 22.84% | 52,671.00 | 1.170 | 53,700.00 | 1.193 | 1,029.00 | 1.95% |
| 50,000 | 1,995.00 | 0.040 | 2,425.00 | 0.049 | 430.00 | 21.55% | 58,490.00 | 1.170 | 59,600.00 | 1.192 | 1,110.00 | 1.90% |
| 55,000 | 2,164.50 | 0.039 | 2,607.50 | 0.047 | 443.00 | 20.47% | 64,309.00 | 1.169 | 65,500.00 | 1.191 | 1,191.00 | 1.85% |
| 60,000 | 2,334.00 | 0.039 | 2,790.00 | 0.047 | 456.00 | 19.54% | 70,128.00 | 1.169 | 71,400.00 | 1.190 | 1,272.00 | 1.81% |
| 75,000 | 2,842.50 | 0.038 | 3,337.50 | 0.045 | 495.00 | 17.41% | 87,585.00 | 1.168 | 89,100.00 | 1.188 | 1,515.00 | 1.73% |
| 100,000 | 3,690.00 | 0.037 | 4,250.00 | 0.043 | 560.00 | 15.18% | 116,680.00 | 1.167 | 118,600.00 | 1.186 | 1,920.00 | 1.65% |
| 150,000 | 5,385.00 | 0.036 | 6,075.00 | 0.041 | 690.00 | 12.81% | 174,870.00 | 1.166 | 177,600.00 | 1.184 | 2,730.00 | 1.56% |
| 200,000 | 7,080.00 | 0.035 | 7,900.00 | 0.040 | 820.00 | 11.58% | 233,060.00 | 1.165 | 236,600.00 | 1.183 | 3,540.00 | 1.52% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| - | 300.00 | 0.000 | 600.00 | 0.000 | 300.00 | 100.00% | 300.00 | 0.000 | 600.00 | 0.000 | 300.00 | 100.00% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 20,000 | 978.00 | 0.049 | 1,330.00 | 0.067 | 352.00 | 35.99% | 23,576.00 | 1.179 | 24,200.00 | 1.210 | 624.00 | 2.65% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 60,000 | 2,334.00 | 0.039 | 2,790.00 | 0.047 | 456.00 | 19.54% | 70,128.00 | 1.169 | 71,400.00 | 1.190 | 1,272.00 | 1.81% |

| Equivalent DRY Therm Present Rate | Block therm | G-63 Rate | |
|---|---|---|---|
| Customer Charge | - | $300.00 | /Customer |
| First | - | $0.0339 | /therm |
| Over | - | $0.0339 | /therm |
| TOTAL CGC & LDAC | | $1.1299 | /therm |
| CGC | | $1.1200 | |
| LDAC | | $0.0099 | |

| Proposed Rate | Block therm | G-63 Rate | |
|---|---|---|---|
| Customer Charge | - | $600.00 | /Customer |
| First | - | $0.0365 | /therm |
| Over | - | $0.0365 | /therm |
| TOTAL CGC & LDAC | | $1.1435 | /therm |
| CGC | | $1.1335 | /therm |
| LDAC | | $0.0099 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Summer Season
C&I - High Annual Use, Load Factor Greater Than 110%
Rate G-63

| | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sales therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% |
| 2,500 | 346.25 | 0.139 | 649.75 | 0.260 | 303.50 | 87.65% | 2,781.25 | 1.113 | 3,118.00 | 1.247 | 336.75 | 12.11% |
| 5,000 | 392.50 | 0.079 | 699.50 | 0.140 | 307.00 | 78.22% | 5,262.50 | 1.053 | 5,636.00 | 1.127 | 373.50 | 7.10% |
| 7,500 | 438.75 | 0.059 | 749.25 | 0.100 | 310.50 | 70.77% | 7,743.75 | 1.033 | 8,154.00 | 1.087 | 410.25 | 5.30% |
| 10,000 | 485.00 | 0.049 | 799.00 | 0.080 | 314.00 | 64.74% | 10,225.00 | 1.023 | 10,672.00 | 1.067 | 447.00 | 4.37% |
| 12,500 | 531.25 | 0.043 | 848.75 | 0.068 | 317.50 | 59.76% | 12,706.25 | 1.017 | 13,190.00 | 1.055 | 483.75 | 3.81% |
| 15,000 | 577.50 | 0.039 | 898.50 | 0.060 | 321.00 | 55.58% | 15,187.50 | 1.013 | 15,708.00 | 1.047 | 520.50 | 3.43% |
| 20,000 | 670.00 | 0.034 | 998.00 | 0.050 | 328.00 | 48.96% | 20,150.00 | 1.008 | 20,744.00 | 1.037 | 594.00 | 2.95% |
| 25,000 | 762.50 | 0.031 | 1,097.50 | 0.044 | 335.00 | 43.93% | 25,112.50 | 1.005 | 25,780.00 | 1.031 | 667.50 | 2.66% |
| 30,000 | 855.00 | 0.029 | 1,197.00 | 0.040 | 342.00 | 40.00% | 30,075.00 | 1.003 | 30,816.00 | 1.027 | 741.00 | 2.46% |
| 35,000 | 947.50 | 0.027 | 1,296.50 | 0.037 | 349.00 | 36.83% | 35,037.50 | 1.001 | 35,852.00 | 1.024 | 814.50 | 2.32% |
| 40,000 | 1,040.00 | 0.026 | 1,396.00 | 0.035 | 356.00 | 34.23% | 40,000.00 | 1.000 | 40,888.00 | 1.022 | 888.00 | 2.22% |
| 45,000 | 1,132.50 | 0.025 | 1,495.50 | 0.033 | 363.00 | 32.05% | 44,962.50 | 0.999 | 45,924.00 | 1.021 | 961.50 | 2.14% |
| 50,000 | 1,225.00 | 0.025 | 1,595.00 | 0.032 | 370.00 | 30.20% | 49,925.00 | 0.999 | 50,960.00 | 1.019 | 1,035.00 | 2.07% |
| 55,000 | 1,317.50 | 0.024 | 1,694.50 | 0.031 | 377.00 | 28.61% | 54,887.50 | 0.998 | 55,996.00 | 1.018 | 1,108.50 | 2.02% |
| 60,000 | 1,410.00 | 0.024 | 1,794.00 | 0.030 | 384.00 | 27.23% | 59,850.00 | 0.998 | 61,032.00 | 1.017 | 1,182.00 | 1.97% |
| 75,000 | 1,687.50 | 0.023 | 2,092.50 | 0.028 | 405.00 | 24.00% | 74,737.50 | 0.997 | 76,140.00 | 1.015 | 1,402.50 | 1.88% |
| 100,000 | 2,150.00 | 0.022 | 2,590.00 | 0.026 | 440.00 | 20.47% | 99,550.00 | 0.996 | 101,320.00 | 1.013 | 1,770.00 | 1.78% |
| 150,000 | 3,075.00 | 0.021 | 3,585.00 | 0.024 | 510.00 | 16.59% | 149,175.00 | 0.995 | 151,680.00 | 1.011 | 2,505.00 | 1.68% |
| 200,000 | 4,000.00 | 0.020 | 4,580.00 | 0.023 | 580.00 | 14.50% | 198,800.00 | 0.994 | 202,040.00 | 1.010 | 3,240.00 | 1.63% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 4,000 | 374.00 | 0.094 | 679.60 | 0.170 | 305.60 | 81.71% | 4,270.00 | 1.068 | 4,628.80 | 1.157 | 358.80 | 8.40% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 30,000 | 855.00 | 0.029 | 1,197.00 | 0.040 | 342.00 | 40.00% | 30,075.00 | 1.003 | 30,816.00 | 1.027 | 741.00 | 2.46% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 60,000 | 1,760.00 | 0.022 | 2,192.00 | 0.027 | 412.00 | 23.15% | 79,700.00 | 0.996 | 81,176.00 | 1.015 | 1,476.00 | 1.85% |

| Equivalent DRY Therm Present Rate | Block therm | G-63 Rate | |
|---|---|---|---|
| Customer Charge | - | $300.00 | /Customer |
| First | - | $0.0185 | /therm |
| Over | - | $0.0185 | /therm |
| TOTAL CGC & LDAC | | $0.9740 | /therm |
| CGC | | $0.9404 | |
| LDAC | | $0.0336 | |

| Proposed Rate | Block therm | G-63 Rate | |
|---|---|---|---|
| Customer Charge | - | $600.00 | /Customer |
| First | - | $0.0199 | /therm |
| Over | - | $0.0199 | /therm |
| TOTAL CGC & LDAC | | $0.9873 | /therm |
| CGC | | $0.9537 | /therm |
| LDAC | | $0.0336 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms)

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Winter Season
C&I - High Annual Use, Load Factor Greater Than 90%
Rate G-54 and G-63 Combined

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate With CGC Revenues | | Proposed Rate With CGC Revenues | | Difference With CGC Revenues | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Revenues Base Rate | Percent Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% |
| 2,500 | 387.10 | 0.155 | 693.50 | 0.277 | 306.40 | 79.15% | 3,211.85 | 1.285 | 3,552.25 | 1.421 | 340.40 | 10.60% |
| 5,000 | 474.20 | 0.095 | 787.00 | 0.157 | 312.80 | 65.96% | 6,123.70 | 1.225 | 6,504.50 | 1.301 | 380.80 | 6.22% |
| 7,500 | 561.30 | 0.075 | 880.50 | 0.117 | 319.20 | 56.87% | 9,035.55 | 1.205 | 9,456.75 | 1.261 | 421.20 | 4.66% |
| 10,000 | 648.39 | 0.065 | 974.00 | 0.097 | 325.61 | 50.22% | 11,947.39 | 1.195 | 12,409.00 | 1.241 | 461.61 | 3.86% |
| 12,500 | 735.49 | 0.059 | 1,067.50 | 0.085 | 332.01 | 45.14% | 14,859.24 | 1.189 | 15,361.25 | 1.229 | 502.01 | 3.38% |
| 15,000 | 822.59 | 0.055 | 1,161.00 | 0.077 | 338.41 | 41.14% | 17,771.09 | 1.185 | 18,313.50 | 1.221 | 542.41 | 3.05% |
| 20,000 | 996.79 | 0.050 | 1,348.00 | 0.067 | 351.21 | 35.23% | 23,594.79 | 1.180 | 24,218.00 | 1.211 | 623.21 | 2.64% |
| 25,000 | 1,170.99 | 0.047 | 1,535.00 | 0.061 | 364.01 | 31.09% | 29,418.49 | 1.177 | 30,122.50 | 1.205 | 704.01 | 2.39% |
| 30,000 | 1,345.18 | 0.045 | 1,722.00 | 0.057 | 376.82 | 28.01% | 35,242.18 | 1.175 | 36,027.00 | 1.201 | 784.82 | 2.23% |
| 35,000 | 1,519.38 | 0.043 | 1,909.00 | 0.055 | 389.62 | 25.64% | 41,065.88 | 1.173 | 41,931.50 | 1.198 | 865.62 | 2.11% |
| 40,000 | 1,693.58 | 0.042 | 2,096.00 | 0.052 | 402.42 | 23.76% | 46,889.58 | 1.172 | 47,836.00 | 1.196 | 946.42 | 2.02% |
| 45,000 | 1,867.78 | 0.042 | 2,283.00 | 0.051 | 415.22 | 22.23% | 52,713.28 | 1.171 | 53,740.50 | 1.194 | 1,027.22 | 1.95% |
| 50,000 | 2,041.97 | 0.041 | 2,470.00 | 0.049 | 428.03 | 20.96% | 58,536.97 | 1.171 | 59,645.00 | 1.193 | 1,108.03 | 1.89% |
| 55,000 | 2,216.17 | 0.040 | 2,657.00 | 0.048 | 440.83 | 19.89% | 64,360.67 | 1.170 | 65,549.50 | 1.192 | 1,188.83 | 1.85% |
| 60,000 | 2,390.37 | 0.040 | 2,844.00 | 0.047 | 453.63 | 18.98% | 70,184.37 | 1.170 | 71,454.00 | 1.191 | 1,269.63 | 1.81% |
| 75,000 | 2,912.96 | 0.039 | 3,405.00 | 0.045 | 492.04 | 16.89% | 87,655.46 | 1.169 | 89,167.50 | 1.189 | 1,512.04 | 1.72% |
| 100,000 | 3,783.95 | 0.038 | 4,340.00 | 0.043 | 556.05 | 14.70% | 116,773.95 | 1.168 | 118,690.00 | 1.187 | 1,916.05 | 1.64% |
| 150,000 | 5,525.92 | 0.037 | 6,210.00 | 0.041 | 684.08 | 12.38% | 175,010.92 | 1.167 | 177,735.00 | 1.185 | 2,724.08 | 1.56% |
| 200,000 | 7,267.89 | 0.036 | 8,080.00 | 0.040 | 812.11 | 11.17% | 233,247.89 | 1.166 | 236,780.00 | 1.184 | 3,532.11 | 1.51% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| - | 300.00 | 0.000 | 600.00 | 0.000 | 300.00 | 100.00% | 300.00 | 0.000 | 600.00 | 0.000 | 300.00 | 100.00% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 20,000 | 996.79 | 0.050 | 1,348.00 | 0.067 | 351.21 | 35.23% | 23,594.79 | 1.180 | 24,218.00 | 1.211 | 623.21 | 2.64% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 60,000 | 2,390.37 | 0.040 | 2,844.00 | 0.047 | 453.63 | 18.98% | 70,184.37 | 1.170 | 71,454.00 | 1.191 | 1,269.63 | 1.81% |

Equivalent DRY Therm Present Rate G-54&G-63

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $300.00 | /Customer |
| First | - | $0.0348 | /therm |
| Over | - | $0.0348 | /therm |
| TOTAL CGC & LDAC | | $1.1299 | /therm |
| CGC | | $1.1200 | |
| LDAC | | $0.0099 | |

Proposed Rate G-54&G-63

| | Block therm | Rate | |
|---|---|---|---|
| Customer Charge | - | $600.00 | /Customer |
| First | - | $0.0374 | /therm |
| Over | - | $0.0374 | /therm |
| TOTAL CGC & LDAC | | $1.1435 | /therm |
| CGC | | $1.1336 | /therm |
| LDAC | | $0.0099 | /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

NATIONAL GRID - NH
Comparison of Present and Proposed Rates
Summer Season
C&I - High Annual Use, Load Factor Greater Than 90%
Rate G-54 and G-63 Combined

| Sales | Present Rate | | Proposed Rate | | Difference | | Present Rate | | Proposed Rate | | Difference | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Revenues | Percent | With CGC Revenues | | With CGC Revenues | | With CGC Revenues | |
| Sales therm | Base Rate | Revenues Per therm | Base Rate | Revenues Per therm | Base Rate | Base Rate | Rate | Revenues Per therm | Rate | Revenues Per therm | Revenues Rate | Percent Rate |
| 0 | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% | $300.00 | NA | $600.00 | NA | $300.00 | 100.00% |
| 2,500 | 347.02 | 0.139 | 650.50 | 0.260 | 303.48 | 87.45% | 2,782.02 | 1.113 | 3,118.75 | 1.248 | 336.73 | 12.10% |
| 5,000 | 394.05 | 0.079 | 701.00 | 0.140 | 306.95 | 77.90% | 5,264.05 | 1.053 | 5,637.50 | 1.128 | 373.45 | 7.09% |
| 7,500 | 441.07 | 0.059 | 751.50 | 0.100 | 310.43 | 70.38% | 7,746.07 | 1.033 | 8,156.25 | 1.088 | 410.18 | 5.30% |
| 10,000 | 488.10 | 0.049 | 802.00 | 0.080 | 313.90 | 64.31% | 10,228.10 | 1.023 | 10,675.00 | 1.068 | 446.90 | 4.37% |
| 12,500 | 535.12 | 0.043 | 852.50 | 0.068 | 317.38 | 59.31% | 12,710.12 | 1.017 | 13,193.75 | 1.056 | 483.63 | 3.81% |
| 15,000 | 582.15 | 0.039 | 903.00 | 0.060 | 320.85 | 55.12% | 15,192.15 | 1.013 | 15,712.50 | 1.048 | 520.35 | 3.43% |
| 20,000 | 676.20 | 0.034 | 1,004.00 | 0.050 | 327.80 | 48.48% | 20,156.20 | 1.008 | 20,750.00 | 1.038 | 593.80 | 2.95% |
| 25,000 | 770.25 | 0.031 | 1,105.00 | 0.044 | 334.75 | 43.46% | 25,120.25 | 1.005 | 25,787.50 | 1.032 | 667.25 | 2.66% |
| 30,000 | 864.30 | 0.029 | 1,206.00 | 0.040 | 341.70 | 39.54% | 30,084.30 | 1.003 | 30,825.00 | 1.028 | 740.70 | 2.46% |
| 35,000 | 958.35 | 0.027 | 1,307.00 | 0.037 | 348.65 | 36.38% | 35,048.35 | 1.001 | 35,862.50 | 1.025 | 814.15 | 2.32% |
| 40,000 | 1,052.40 | 0.026 | 1,408.00 | 0.035 | 355.60 | 33.79% | 40,012.40 | 1.000 | 40,900.00 | 1.023 | 887.60 | 2.22% |
| 45,000 | 1,146.44 | 0.025 | 1,509.00 | 0.034 | 362.56 | 31.62% | 44,976.44 | 0.999 | 45,937.50 | 1.021 | 961.06 | 2.14% |
| 50,000 | 1,240.49 | 0.025 | 1,610.00 | 0.032 | 369.51 | 29.79% | 49,940.49 | 0.999 | 50,975.00 | 1.020 | 1,034.51 | 2.07% |
| 55,000 | 1,334.54 | 0.024 | 1,711.00 | 0.031 | 376.46 | 28.21% | 54,904.54 | 0.998 | 56,012.50 | 1.018 | 1,107.96 | 2.02% |
| 60,000 | 1,428.59 | 0.024 | 1,812.00 | 0.030 | 383.41 | 26.84% | 59,868.59 | 0.998 | 61,050.00 | 1.018 | 1,181.41 | 1.97% |
| 75,000 | 1,710.74 | 0.023 | 2,115.00 | 0.028 | 404.26 | 23.63% | 74,760.74 | 0.997 | 76,162.50 | 1.016 | 1,401.76 | 1.87% |
| 100,000 | 2,180.99 | 0.022 | 2,620.00 | 0.026 | 439.01 | 20.13% | 99,580.99 | 0.996 | 101,350.00 | 1.014 | 1,769.01 | 1.78% |
| 150,000 | 3,121.48 | 0.021 | 3,630.00 | 0.024 | 508.52 | 16.29% | 149,221.48 | 0.995 | 151,725.00 | 1.012 | 2,503.52 | 1.68% |
| 200,000 | 4,061.98 | 0.020 | 4,640.00 | 0.023 | 578.02 | 14.23% | 198,861.98 | 0.994 | 202,100.00 | 1.011 | 3,238.02 | 1.63% |
| Estimated Bill Percentile - 25% | | | | | | | | | | | | |
| 4,000 | 375.24 | 0.094 | 680.80 | 0.170 | 305.56 | 81.43% | 4,271.24 | 1.068 | 4,630.00 | 1.158 | 358.76 | 8.40% |
| Bill Percentile - 50% | | | | | | | | | | | | |
| 30,000 | 864.30 | 0.029 | 1,206.00 | 0.040 | 341.70 | 39.54% | 30,084.30 | 1.003 | 30,825.00 | 1.028 | 740.70 | 2.46% |
| Estimated Bill Percentile - 75% | | | | | | | | | | | | |
| 60,000 | 1,428.59 | 0.024 | 1,812.00 | 0.030 | 383.41 | 26.84% | 59,868.59 | 0.998 | 61,050.00 | 1.018 | 1,181.41 | 1.97% |

Equivalent DRY Therm Present Rate G-54&G-63

| | Block therm | Rate |
|---|---|---|
| Customer Charge | - | $300.00 /Customer |
| First | - | $0.0188 /therm |
| Over | - | $0.0188 /therm |
| TOTAL CGC & LDAC | | $0.9740 /therm |
| CGC | | $0.9404 |
| LDAC | | $0.0336 |

Proposed Rate G-54&G-63

| | Block therm | Rate |
|---|---|---|
| Customer Charge | - | $600.00 /Customer |
| First | - | $0.0202 /therm |
| Over | - | $0.0202 /therm |
| TOTAL CGC & LDAC | | $0.9873 /therm |
| CGC | | $0.9537 /therm |
| LDAC | | $0.0336 /therm |

NOTE: The present CGC rate reflects approved rates. All present rates are restated to Dry therms to allow comparison with proposed rates (also in dry therms).

# ATTACHMENT

# GLG-RD-5

# DETAILED DISCUSSION OF METHODOLOGIES

The purpose of this supplemental testimony is to provide a full and complete explanation of the accounting and marginal cost studies and the proposed rate design. The direct testimony and the first four attachments are supplemented with this attachment as well as a complete set of workpapers. Given the large number of supporting documents and files that make up these workpapers, it would be difficult to develop an understanding of this material without further explanation. Attachment GLG-RD-5 is intended to provide a more detailed explanation of the computational aspects of the rate filing than is provided in my direct testimony. Interested parties can review either the detailed level of this filing in this supplemental testimony or assess the summary results provided in my direct testimony.

My supplemental testimony addresses three topics as follows:

1. A description of the Accounting Cost of Service Study used to segregate revenue requirements between gas supply and delivery service functions,
2. A discussion of the methods employed in the Marginal Cost Study to allocate delivery service revenue requirements among classes, and
3. The computation of design day demands necessary for the marginal cost study and the allocation of gas costs. These design day demands are provided in Attachment GLG-RD-1.

Cost of Service Study

The accounting cost of service model presented in Attachment GLG-2 is essentially a cost matrix. The vertical dimension or rows of the study consists of the costs to serve as provided by the Company. The development of cost of service study begins with rate base and continues with revenues, operating expenses, taxes, income and rate of return and the computation of a labor allocator. The cost model includes three additional reports, a summary of costs to serve, a list of the allocation factors employed in the study and a revenue requirements presentation.

The horizontal portion or columns consists of either customer classes or cost functions. Each page has an important column immediately preceding the numerical data marked "ALLOC", an abbreviation for Allocator. The ALLOC column contains an acronym to indicate the allocation factor used to allocate the costs shown in the Total Company Column to individual customer classes. A tabulation of these allocators in absolute form, typically total dollars or volumes and as a percent of total, has been provided at the end of each study.

Using these allocation factors, costs shown in the Total Company column are assigned to each function shown on the horizontal of the cost study. The cost of service information provided in the vertical column can be of two forms: either per books numbers as reported for the test year or pro forma adjustments, to reflect the weather normalization adjustments.

Attachment GLG-RD-2 was prepared to assist in the quantification of indirect gas costs and presents the results of my functional cost of service study. This study is structured similar to previous cost studies filed on behalf of National Grid NH; however, it has been simplified to include only that information relevant to the development of indirect gas costs. Instead of identifying the costs to serve each customer class, each cost component and each functional area, this study only computes functional costs. It does so by examining each element of rate base and operations expense and allocating or otherwise assigning it to one of three functions - the delivery function, the direct gas cost function or the indirect gas cost function. These functional costs are provided on Attachment GLG-RD-2-1.

The functional cost study provided in Attachment GLG-RD-2-1 employs the same methodologies as the cost studies filed in support of indirect gas costs in Docket Nos. DG 00-063 and DG 07-093. The study filed as Attachment GLG-RD-2-1 utilizes the same allocation factors and provides the same information in its output reports as the previous studies. The only difference is that the vertical layout of the cost study has been updated to reflect the revenue requirements proposed in this case.

The cost study incorporates the actual costs incurred by the Company for the 12 months ended June 30, 2007 with known and measurable changes. I have computed the gas working capital based on a recently completed lead lag study indicating that the lag for direct gas costs is 12.04 days.

The cost of service study, Attachment GLG-RD-2-1, consists of 24 pages. Pages 1, 2 and 3 provide summary information. Pages 4 through 14 identify each element of rate base and operations expense included in the utility's costs to serve. Pages 15 through 24 develop and tabulate the allocation factors used in the cost study.

Following the method employed by the Company in its previous functional cost study and similar to most other utilities, I observed that National Grid NH's local production facilities serve both a production and a delivery function. Prior to unbundling, cost analysts would assume that all production facilities were dedicated to the supply function. However, from a strict practical operating perspective, that is not the case; local production investments are used jointly between the supply and delivery functions. Production facilities can be used to avoid significant distribution system investments for looping and upgrading, thereby providing a delivery function. This study estimates the economic costs associated with these operating functions.

The Company's investment in liquid propane air ("LP-air") and liquefied natural gas ("LNG") manufactured gas facilities was segregated between gas supply and pressure support functions. An analysis of the distribution system pressures on the design hour revealed that approximately 12.4% of the Company's peaking capacity is used for pressure support and can be considered as an investment in lieu of distribution reinforcement. This analysis assumed that an unlimited supply of pipeline-delivered gas was available at the utility's gate stations. Then it used the Stoner distribution simulation model to compute the pressure losses across the distribution system in the design hour, when flows are at their maximum. The resulting analysis identified pressure drops that fell below acceptable standards making reliable delivery impossible without the injection of natural gas and concurrent pressure support from the locally manufactured gas facilities. The results of this analysis are summarized in my marginal cost study on Attachment GLG-RD-3, ~~Table 1,~~ page 3 of 37. The results indicate that 7,207 decatherms of design day capacity are required to maintain distribution pressures at an acceptable level. This figure equates to 12.4% of the total manufactured gas capacity. Consequently, I assumed that all production plant and related costs were allocated 87.6% to the supply function and 12.4% to the delivery function.

In order to provide an accurate functional cost study, the marginal study set forth in Attachment GLG-RD-3 re-functionalized a number of costs including the manufactured gas costs between the categories of production expense and distribution expense, National Grid NH is the gate station operator for its service territory. Many of the functions provided at the gate station benefit both bundled sales and transportation customers. For example, the gate station operator must confirm the nominations for its sales customers as well as the nominations of the suppliers selected by its transportation customers. Therefore, costs such as these have both a supply and delivery function. Unfortunately, the accounting system does not provide this same level of information. Some of the costs booked in Account 722 Other Production Supplies & Expenses, provide a joint supply and delivery function. Based upon a more detailed analysis of the costs accumulated in this account, $34,636 (i.e., 18.8%) of expenses in this production account were re-classified to the delivery function relating to the provision of transportation services.

I also identified several other operating and maintenance expenses that should be included in the category of indirect gas cost. A review of Attachment GLG-RD-2-1 will show that there are many non-production related expense categories that include supply-related costs including customer accounting expenses, sales expense and administrative and general ("A&G") expenses.

Most A&G expenses are allocated on the basis of labor. Consequently, the use of production labor costs to allocate A&G expenses produces a significant allocation of A&G expense to the functions other than the delivery function.

Uncollectible accounts expense in Account 1783 was examined to determine the portion applicable to the supply function. As with the Company's previous studies, uncollectible accounts expenses were allocated to functions on the same basis as overall revenue requirements. Since supply costs represent the majority of revenue requirements, it is reasonable that uncollectible accounts expense should also be allocated more heavily to the supply category. As a result, nearly $3.4 million of uncollectible accounts expense were assigned to the indirect gas cost category.

The summary provided on page 1 of Attachment GLG-RD-2-1 displays the calculation of net revenue and rate of return for the Company in total and for each of its major functions. The presentation is fairly straightforward. The first twelve lines summarize the development of rate base. Lines 13 through 15 show current revenues. Lines 16 through 22 detail expenses allowing the computation of operating income on line 23 and the rate of return at current rates on line 24. Line 25 provides the "index rate of return", also known as the relative rate of return, which sets forth each function's rate of return in relation to the total Company rate of return. Net revenues are provided on line 26 of page 1 of

Attachment GLG-RD-2-1. Page 1 presents the results of operations under present rates. Therefore, the sales revenues on line 13 represent the delivery and supply revenues collected by the Company's unbundled rates. This page shows that the current rates allow the Company to earn a 5.28% return on its rate base investment. However, that return is not earned uniformly across each function. The delivery function is currently earning a return of 6.15% while the supply functions produce a negative operating income of $877,581. Since the direct gas costs are reconciling, the gas costs and the gas revenues are equal, and there is no return generated for direct gas costs. Therefore, all of the supply function operating losses stem from an under-recovery of indirect gas costs.

Page 2 of Attachment GLG-RD-2-1 is very similar to the first page except that instead of using current revenue, it uses claimed revenue necessary to achieve the company's claimed rate of return. This difference is shown on the sales revenue row. For this page, sales revenues for each function were set at levels sufficient to generate a rate of return of 9.26%, the requested rate of return for the Company in this filing. I have provided a third summary, shown on page 3, to compare the differences between pages 1 and 2.

The first five lines of Page 3 of Attachment GLG-RD-2-1 show information taken from page 1, reflecting current operations. Line 6 tabulates therm sales used for the computation of unit costs elsewhere on the page. The lower portion of this page, labeled "Claimed Rate of Return", shows the impact of establishing rates to generate the Company's currently allowed rate of return on equity for each function. For example, line 14 shows that an overall increase of 5.53% would be required to raise the Company's rate of return to 9.26%. Column 4 shows that no increase would be required for direct gas costs since, once again, they are reconciling and have no associated rate base. The Cost of Gas Clause ("COGC") insures that direct gas cost rates are set equal to direct gas costs. However, as shown in the last column, indirect gas costs require a 71.6% increase or roughly $2.5 million dollars annually in order to achieve the allowed rate of return.

The cost of service study information should be employed to update the approved figures in the COGC. Attachment GLG-RD-2-2 presents a lower level of detail taken from the cost study. This schedule, consisting of three pages, shows the breakdown of indirect gas costs into the four categories included in the COGC, namely: (1) LPG and LNG, (2) Miscellaneous Production Costs, (3) Bad Debt Expense excluding the Bad Debt already included in the LP & LNG costs, and (4) Working Capital. These four categories, when added together, equal total Indirect Gas costs.

The format of Attachment GLG-RD-2-2 is similar to the first three pages of the functionalized cost of service study, Attachment GLG-RD-2-1. Page 3 of

Attachment GLG-RD-2-2 line 12 shows the revenue requirements for each category of indirect gas costs.

Attachment GLG-RD-2-3 provides a concise summary of the information taken from the cost of service study. This schedule shows that the Production and Storage factor, PS, should be $1,869,226; the miscellaneous expense factor, MISC, has also declined and should now be $56,975. The Working Capital Allowance WCA%, reflecting the new lead-lag study's results, should be 0.522%. Finally, commensurate with the growth in uncollectible accounts expense, the revised BD% should be set at 2.509%.

The table below should be substituted on page 20 of National Grid NH's tariff, NHPUC No. 5 Gas.

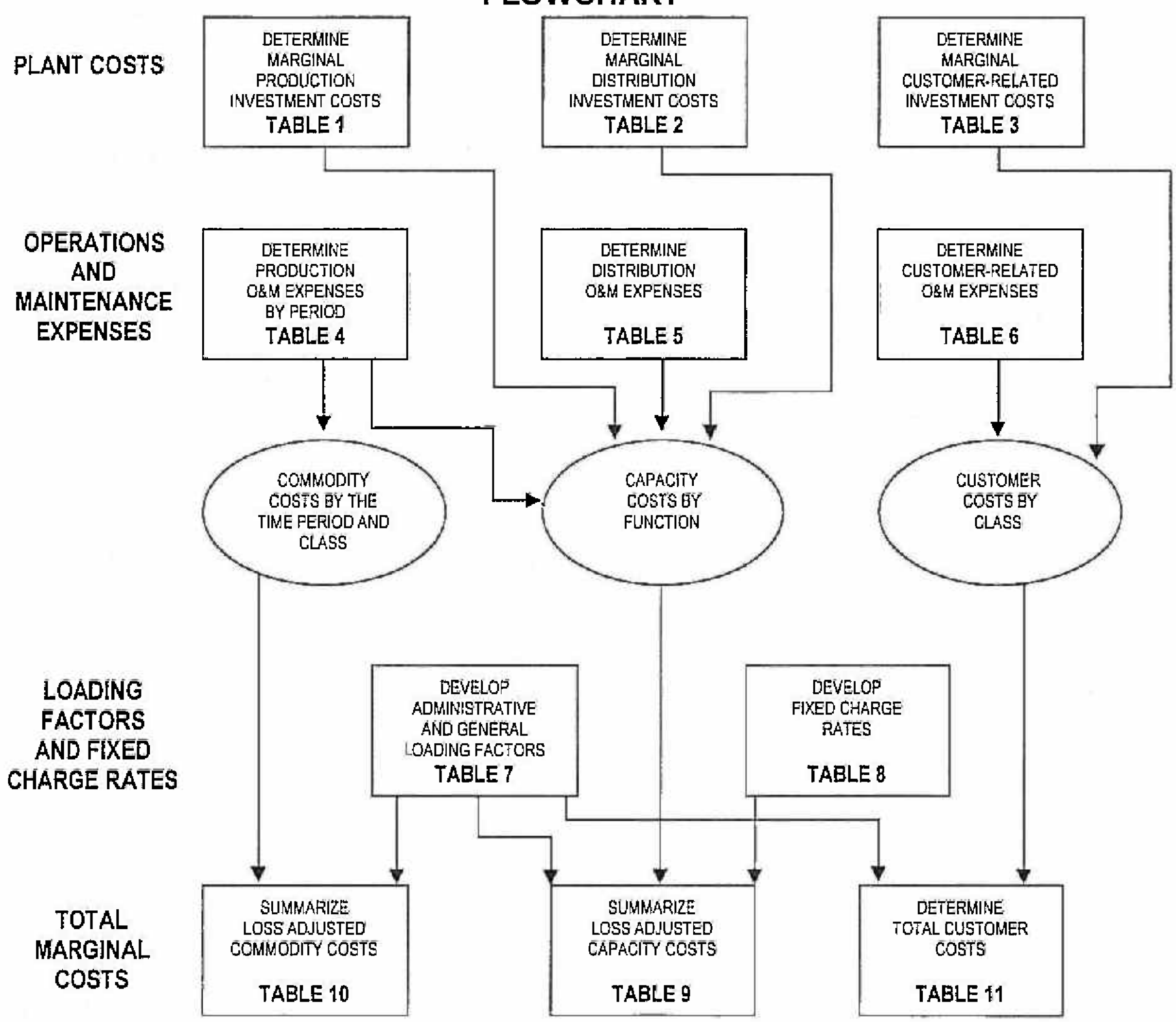
| Variable | Description | Approved Figure |
|---|---|---|
| MISC | Miscellaneous Overhead | $56,975 |
| PS | Production and Storage Capacity | $1,869,226 |
| WCA% | Working Capital Allowance Percentage | 0.522% |
| BD% | Bad Debt Percentage | 2.509% |

## Marginal Cost Study

The marginal cost study, presented as Attachment GLG-RD-3, employs a very logical organization. The study consists of fourteen different tables and supporting calculations. The organization of the marginal cost study can be understood by referring to the attached flow chart (Figure 1). This flow chart shows the logical progression of data in the marginal cost study beginning with plant investment data and proceeding through to the development of marginal unit costs to serve. The summary output from the marginal cost study is shown on Table 14 which is page 37 of 37 of Attachment GLG-RD-3. This table and supporting detail show the results of the marginal cost study along with calculations leading to these results.

The flow chart that follows provides the discrete computations made in the marginal cost study. The first three tables comprising the first 9 pages of the marginal cost study develop the plant investment necessary to serve growth. Table 1 (pages 1 through 3 of Attachment GLG-RD-3) develops the investment in production plant necessary to serve an increment of customer load. Table 2 (pages 4 through 8 of Attachment GLG-RD-3) addresses the capacity-related distribution plant investments, while Table 3 (page 9 of Attachment GLG-RD-3) addresses customer-related investments to the distribution system. Table 4 (pages 10 and 11 of Attachment GLG-RD-3) details the development of estimated marginal production O&M expenses, both commodity and capacity. Table 5 (pages 12 and 13 of Attachment GLG-RD-3) computes marginal distribution capacity-related O&M expenses. Table 6 (pages 14 through 18 of Attachment GLG-RD-3) estimates customer-related O&M expenses. Table 7 (pages 19 and 20 of Attachment GLG-RD-3) develops loading factors used to account for marginal costs not individually estimated, such as administrative and general expenses. Table 8 (pages 21 through 31 of Attachment GLG-RD-3) develops levelized fixed charge rates used to translate one-time capital investments into annual revenue requirements. Tables 9, 10, and 11 (pages 32 through 34 of Attachment GLG-RD-3) summarize the results of all calculations, depicting the quantification of marginal capacity, commodity, and customer-related costs, respectively.

**MARGINAL COST STUDY FLOWCHART**



**SUMMARIES**

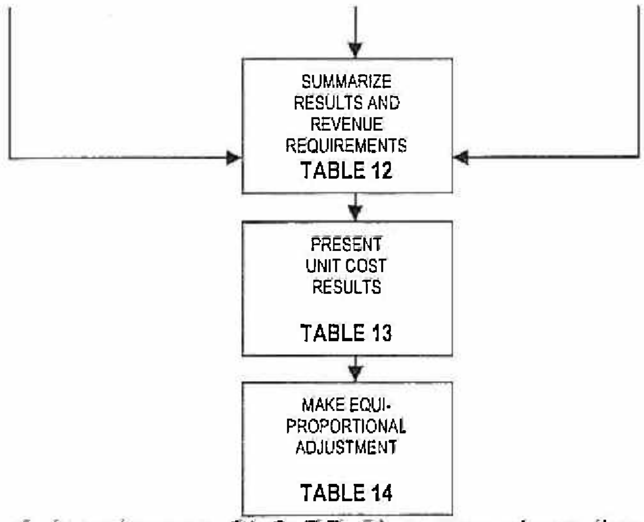



Table 12 (page 35 of Attachment GLG-RD-3) summarizes these component costs. Table 13 (page 36 of Attachment GLG-RD-3) converts the ~~Table 12~~ costs set forth on page 35 into marginal unit costs. Finally, Table 14 (page 37 of Attachment GLG-RD-3) adjusts the marginal costs for each class using the equi-proportional method so that the sum of the class adjusted marginal costs equals the proposed delivery system revenue requirement of $49,633,399 identified on Attachment GLG-RD-2-1, page 3, line 12, column (2).

Demand or capacity investments for gas distribution companies consist of production, transmission and distribution functions. Production capacity costs are the unitized costs of expanding the Company's production capability to meet a long-run increase in customers' requirements for gas service. Normally, when conducting a marginal cost study to determine delivery costs to serve, one would assume that all production costs, both capacity and commodity costs, fall into the category of supply costs and would be excluded from a study measuring only delivery costs. However, as mentioned previously, the National Grid NH distribution system operates in such a manner that 12.4% of production capacity was and will continue to be used to support the distribution system.

Under most conditions, a small increase in customer demand will cause the Company to incur little or no additional cost. With few exceptions, the Company will meet any additional load with its existing supply sources. However, at some point the load increment will demand that the Company acquire additional sources of supply. In practice, a gas utility may expand its production capacity by increasing the amount of gas it may take under a firm contract from a supplier, by expanding its storage capacity, or by increasing its ability to supply itself from production facilities, such as an LP-air or an LNG vaporizer.

The marginal cost analysis presented in this filing utilizes the peaker method with which the PUC is familiar. This method has been employed in National Grid's (formerly Energy North's) filings in Docket No. 95-121 and DG 00-063, in Northern Utilities-New Hampshire Division's marginal cost studies filed in Docket Nos. DR94-177 and DR95-236, as well as in most electric utility rate cases. In simple terms, the peaker method identifies the least capital intensive capacity source that can be added to the Company's resources to meet peaks of short duration. For National Grid NH, a new LP storage and vaporization facility located in Tilton, NH, including a supporting distribution pipeline-expansion was the on-system alternative examined in the Company's assessment of alternatives to meet local design hour pressure requirements. Because the marginal cost study is attempting to measure only the costs associated with meeting delivery demands, the fact that the LP project alternative represents the most viable option for meeting the identified need without incremental pipeline capacity is by definition the incremental cost of marginal capacity.

I specifically chose the peaker method to measure marginal production capacity costs in this study. While there are several methods of measuring production capacity costs, I believe that the peaker method provides the most useful information in this docket, where the analysis of delivery costs is required. Marginal gas supply cost data will have no use in the design of delivery rates except to provide directly applicable information necessary to determine the pressure support component of delivery rates.

Let me explain the development of the production plant capacity number shown on ~~Table 1,~~ page 1 of Attachment GLG-RD-3. The data on this ~~table~~ page is derived from the testimony submitted by Company witness John Stavrakas in DG 07-101, the Company's petition to the Commission for approval of a Tennessee Gas Pipeline expansion of the Concord lateral. The development of production plant capacity begins on ~~Table 1,~~ page 2, of Attachment GLG-RD-3. The Company identified a potential 25,200 Dt per day capacity increase for construction of a proposed new LP vaporization and storage facility at Tilton Total project costs of this $37.9 million facility include storage, refrigeration, pipeline connections to and from the project, land, and overhead costs. The unit costs are shown at the bottom of this page

Page 1 of Attachment GLG-3, Table 1, shows the modified peaker method to compute the long-run marginal capacity costs. This method discounts the costs of pure capacity when current capability exceeds current requirements. The Company's cost estimate for its Tilton LNG plant is stated in nominal Dollars for the first year of capacity shortfall, which occurs three years past the base year of the study. Page 1 of ~~Table 1~~Attachment GLG-RD-3, presents the modified peaker cost calculation, showing a reduction to the peaker cost estimate to reflect the discounted value of the present value of a future plant addition.

Distribution capacity costs were computed in two pieces - the long-run marginal costs of adding main extensions to serve new load and the long-run marginal costs of reinforcing the existing gas distribution system to support the additional loads expected.

Table 2 of Attachment GLG-RD-3, consisting of ~~five pages,~~ pages 4 through 8, develops my estimate of the costs to expand the distribution system. My approach, identified as the "Main Extensions and System Reinforcement" method is detailed on pages ~~3~~ 6 and 4 7. Page ~~4~~ 7 develops an estimate of the anticipated unit cost of additional main extensions based on an analysis of historical main extension footage, load, and cost. However, load growth places additional load on the Company's existing distribution system and requires reinforcement of that system. Page ~~3~~ 6 shows an 11-year, forward-looking distribution system estimate of the costs of system reinforcements. For the current year and each of the next five years individually and in composite for years six through ten, the Company's distribution engineering personnel estimated design hour flow requirements, identified any anticipated pressure problems, engineered a resolution and identified the necessary cost. This analysis excluded the expected load growth and distribution investment to serve the Tilton area, since expected additions are required to serve prior period load growth as well as future growth. The cost of reinforcements was estimated using the incremental cost to reinforce the remainder of the distribution system and the expected load growth served by these additions.

Table 4, page 10 of 37, typically calculates marginal commodity costs. But, because this study is used only to allocate distribution revenues, the only costs estimated on this table are the production expenses associated with transportation as shown on page ~~2~~ 11 of 37. As I previously identified, 12.4% of the production capacity is used to support the distribution system, therefore 12.4% of the production expenses are allocated to the distribution function.

The calculation of capacity-related component of Distribution O&M expenses is shown on Table 5 consisting of two pages, pages 12 and 13 of Attachment GLG-RD-3. On the ~~second~~ page13, I reviewed distribution O&M expenses account by account for the historical period. I directly assigned Meter Operating Labor & Expense, Maintenance of Services & Maintenance of Customer's Meters all to the customer component. In addition, I pro-rated Superintendence in Account 1756 to the customer and capacity components in proportion to all other distribution O&M expenses.

On page 12~~1~~ of ~~Table 5~~Attachment GLG-RD-3, I restated the annual capacity-related expenses in terms of current cost, indexing by the GNP Implicit Price Deflator, to determine capacity-related O&M expenses in current dollars. The use of plastic mains, over the past decade, has significantly reduced maintenance costs. Regressing these figures against time resulted in the regression results shown at the bottom of this Table. The regression closely approximated the current average cost which has been stable for virtually every period examined. This suggests that growth requires mains reinforcement and addition of new main, requiring approximately the same maintenance costs as existing mains. I have employed the short term marginal investment per design day decatherm as the best estimate of future marginal costs.

The development of marginal capacity costs is shown on Attachment GLG-RD-3, ~~Table 9~~page 32 of 37. This table develops marginal capacity costs by function. Plant investments identified in Tables 1 and 2 on pages 1 through 8 are grossed up to include general plant. Applying the fixed charge rates developed on pages 21 through 31~~Table 8~~ annualizes these investments. To this amount, annual operating expenses are added, including an allowance for A&G expenses. An adjustment reflecting annual revenue requirements to finance working capital is added. Next, the indicated unit costs were increased to reflect unaccounted for losses experienced. Finally, these costs were escalated from test year to rate year levels.

Marginal customer costs are summarized on Attachment GLG-RD-3, Table 11, which is page ~~1~~ 34 of ~~1~~37. The long-run marginal costs of serving an additional customer were determined to be a function of the size of the customer and the class of service. Three different customer costs were computed, representing the costs of connecting and serving a customer for each of the Company's new rate categories. These customer costs consist of:

(1) Plant investment in services and meters,

(2) Related operations and maintenance expenses, and

(3) Billing costs such as customer accounting and customer information expenses.

The computation of customer-related plant investment began with services, as shown on ~~Table 3,~~ page ~~1~~9 of 37. I received engineering department estimates for service construction typical costs new for each customer class and then adjusted these estimates by the services-per-customer ratio.

Meter investment was developed from current meter cost data Recent cost accounting data provided the current installation costs and regulator costs, which were applied as a percentage adder to meter investment.

The computation of customer-related operations and maintenance expenses are summarized on Table 6, consisting of ~~five~~ pages 14 through 18. On ~~the first~~ page 14, customer-related distribution O&M expenses previously identified on ~~Table 5,~~ page ~~2~~13, were restated in current dollars, using the GNP Implicit Price Deflator as a cost index. The average costs have no significant trend over time. Because the regression equation did not appear to be a reasonable predictor of customer related expenses the average deflated cost per customer from 1989 through 2006 was used as the marginal customer costs. Page ~~2~~ 15 of ~~this table~~Attachment GLG-RD-3 shows the allocation of costs to customer classes, based on the services and meters investments required.

Page ~~3~~ 16 ~~of this schedule~~ shows the development of customer accounting and marketing services expenses. In general, the number of customers has been increasing, while these customer-related expenses have been roughly keeping pace. However, no valid statistical correlation was demonstrated. Discussion with Company personnel revealed that the post-merger data since 2003 would be most representative of future. The average marginal unit cost for the period 2003 to 2006 was chosen as a proxy for the average marginal customer accounting and marketing costs. The cost was assumed to be equal for all customer classes.

The customer charges shown on ~~Table 6,~~ page ~~3~~17~~,~~ specifically exclude uncollectible accounts expense. A separate analysis of the uncollectible costs is shown on ~~Table 6,~~ page ~~4~~18. The actual write-off experience by rate class for the test year has been adjusted on a pro rata basis to reflect the average write-off rate of 2.54% developed from a three year historical average and employed by the Company in this filing.

Attachment GLG-RD-3, Table 7, consisting of ~~two~~ pages 19 and 20, develops loading factors used in the marginal cost study. Loading factors are used to compute estimates of marginal costs where direct quantification is either too complex or the costs are insignificant. In the former category, administrative and general expenses are only indirectly related to customer load characteristics.

To simplify quantification of marginal costs, A&G costs are related to other O&M expenses or plant-related items.

Losses, sendout, unaccounted for, and company use cannot be directly attributed to classes and are computed as a loss factor for use on Tables 9 and 10 which are pages 32 and 33 of Attachment GLG-RD-3. Page ~~2~~ 20 ~~of Table 7~~ also develops 4-year average loading factors for Materials and Supplies and Prepayments, Fuel Inventory, and General Plant. This period was chosen in order to accurately reflect the post-merger operations of the Company.

The development of the carrying charge rates is shown in Attachment GLG-RD-3, ~~Table 8~~21 through 31. ~~This table~~These pages details the development of the levelized fixed charged rates for peaking production facilities, capacity-related distribution plant and customer-related distribution plant. These rates are used to convert one-time investments into annualized revenue requirements, necessary for pricing. For rate-making purposes, utility investments in fixed plant are normally treated as rate base items. Utility rates are established periodically to allow the recovery of costs incurred in ownership, including such items as return, taxes, depreciation, etc. Rather than deal with an irregular set of annual costs stemming from ownership of assets, levelized fixed charge rates compute the present worth of all revenue requirements stemming from utility ownership of an asset, and then provide an equivalent annual payment stream of identical present worth.

The development of a levelized fixed charge rate applicable to Production plant investment is shown on pages ~~2~~22, ~~3~~ 23 and ~~7~~27. The calculations for capacity-related distribution plant (pages 22, ~~2~~24, ~~4~~ aand ~~8~~28), services (pages ~~2~~22, ~~5~~ 25 and ~~9~~29), and metering investment (pages ~~2~~22, ~~6~~ 26 and ~~10~~30) are similar. For simplicity, I will only discuss the calculation of the production plant carrying charge rate.

Page ~~2~~ 22 of 37 of Attachment GLG-RD-3 shows the input assumptions used to develop levelized fixed charge rates. A hypothetical investment of $1,000 is used for demonstration purposes. Page ~~11~~ 31 shows the development of weighted average service lives and salvage values used as input into the computations. Using current property tax rates and incremental income tax rates, the calculation of annual utility revenue requirements stemming from the initial $1,000 investment is shown on page ~~7~~27.

Pages ~~3~~ 23 through 26 displays two different fixed charge rates -- the "engineer's" and "economist's" fixed charge rates. The first fixed charge rate is akin to a banker's conventional fixed rate mortgage. It represents a percentage of the original investment that must be made in current year dollars, in order to equate to the present worth of the utility's revenue requirements. The economist's fixed charge rate differs slightly, in that is assumes that payments will escalate each year by the rate of inflation. Inherent in the engineer's fixed charge rate is the assumption that an asset is depleted more rapidly at the outset than toward the end of its service life. The economist's fixed charge rates make the opposite assumption -- that an asset's utility at the beginning of its service life is equal to its value at the end of its service life. In the gas utility industry, old plant is nearly as useful as new plant. As an example, meters provide the same service at the beginning of their lives as they do at their end. Consequently, the economist's fixed charge rate was used to convert one-time plant investments into annual revenue requirements.

Attachment GLG-RD-3 Table 12, provided on page 35, tabulates the long-run marginal costs computed on pages 32 through 34 and presents this information as Tables 9, 10 and 11. In addition, ~~this table~~page 35 calculates the revenues that would be generated if the Company were to introduce full marginal cost-based pricing and if customers were to continue to consume on the basis of the demands that they are expected to produce on a design day. Obviously, it is impossible to implement such pricing because the revenues generated would far exceed the Company's claimed revenue requirement. The last line on this page shows the monthly revenue requirements that each customer should provide based upon historical consumption. This summary is presented for all customers receiving firm delivery services. It is important to note that the marginal costs for delivery service consist entirely of fixed costs and fall into two categories: those that vary in the long run with the number of customers in a class and those that vary in the long run with the distribution system capacity needed to serve aggregate class design day demands. None of the costs vary in the short run and none vary with sales volumes. Unfortunately, it is impractical to attempt to price customer consumption on the basis of their anticipated design day demand.

~~Table 13~~ Page 36 of 37 of Attachment GLG-RD-3 derives unit costs based on billed sales in the winter and summer months, even though these costs do not vary on the basis of therm sales. Seasonal revenue requirements from page ~~Table 12~~35 were divided by seasonal sales to derive unit costs.

Attachment GLG-RD-3, ~~Table 14~~page 37, adjusts marginal costs to allowed revenues. The equi-proportional method is used in accordance with Commission precedent. Under this method, all marginal costs are adjusted by a uniform percentage to match the test year revenue requirements. The unit costs shown at the bottom of this schedule represent the optimal prices if rates were constrained to customer charges and therm charges, as they have in the past. It shows that delivery service is free in the summer and that all marginal capacity costs should be recovered in the winter. A closer scrutiny of the data reveals that all marginal costs are incurred to serve design day demand, and a truly optimal rate design would bill customers an amount designed to recover their marginal costs to serve.

Design Day Demand Estimates

Design Day Demand Estimates were employed in the development of costs for the accounting and the marginal cost studies. Design day demands represent the largest daily load for which the utility intends to provide reliable service and for which it designs its system. From a practical standpoint, design day demands can be interpreted as the load expected on the coldest anticipated day. Design day demand estimates play an essential role in utility planning and in determining cost responsibilities in this filing. The design day demand estimates for each customer class were employed in the marginal cost study to establish forward looking cost responsibilities. These costs became the basis for establishing class revenue responsibilities. The class design day estimates were also employed in the development of allocation factors for capacity related costs such as the costs of mains, pressure stations, and storage, in the accounting cost of service study.

Since design day temperatures occur so infrequently, natural gas distribution companies such as National Grid NH have limited data upon which to measure aggregate system design day demands, And, because customer consumption is metered monthly, the company has no daily demand data at the rate class level. Therefore, this demand measure and the rate class allocation must be estimated. In order to insure reasonable estimates, I selected the best estimate using two alternative methods. The first method is called the "Regression Method" and is the preferred method when the regressions are sufficiently robust. Under this approach, the monthly sales data is deemed the independent variable and regressed against the degree days ("DDs") in the customer's billing cycle. Using conventional Least Squares Fit regression techniques, the data is used to generate an equation of the form:

$$Y = a + bX$$

Where "a" is the Y-intercept and is interpreted as the customer's base use in the absence of any heating load

and

Where "b" is the slope of the equation and represents the customer's heating increment, i.e., the customer's additional use in therms per degree day.

When a valid regression was established the class load was estimated using the Company's planning criteria, to be able to provide firm service up to 73 heating degree day s[1]. The regression method was employed whenever the statistical

[1] For the purposes of this study 73 heating degree days were used as the design day standard in place of the 80 effective degree day standard the company uses for supply planning purposes because the billing degree day data used for the analysis are measured as heating degree days.

analysis revealed a high degree of correlation as measured by the value of R-Squared, a "goodness of fit" statistic.

The second method is called the Peak Month Average Use Method. In this method the design day for the class is calculated as the average daily use for the class during the peak month of January[2].

National Grid NH's Design Day demands by class employ a combination of approaches, depending upon which approach was the most reasonable. The regression method yield high correlations and was used for all classes except G-54, LgLF<110, and G-63, LgLF=110. A review of the regression statistics for the models used to predict Design Day demands for all but these two classes were excellent, suggesting a high correlation between usage and heating degree days. For the G-54 and G-63 regression models, the R-Squared, or coefficient of correlation did not support the use of the regression method for estimating Design Day Demands. For each of these classes, the Peak Month Average Use Method was employed.

Attachment GLG-RD 1 summarizes the development of class design day demand estimates. Once the individual class estimates were prepared, they

[2] Because of a prior period billing adjustment made to G-54 sales in January 2007, February 2007 sales were used to calculate the design day estimate for this class.

were adjusted from wet therms to dry therms, and adjusted for system lost and unaccounted for gas. Summing the resulting loads represented an estimate of the system's design day demand. Since the utility routinely predicts its total system design day demand, a pro rata adjustment to the individual class estimates was applied to adjust them to match the system's forecasted design day demand. These adjusted class estimates were then reduced by the same loss factor. The resulting estimates represented the expected aggregate class load at the customers' meters on a design day.

# STATE OF NEW HAMPSHIRE
# BEFORE THE
# PUBLIC UTILITIES COMMISSION

**EnergyNorth Natural Gas, Inc.**

**d/b/a National Grid NH**

**DG 08-009**

**Direct Testimony**

**Of**

**John E. O'Shaughnessy**

ORIGINAL
N.H.P.U.C. Case No. DG 08-009
Exhibit No. #1
Witness
DO NOT REMOVE FROM FILE

**February 25, 2008**

## TABLE OF CONTENTS

**Page**

**Q. Please state your name and business address.**

A. My name is John E. O'Shaughnessy. My business address is One MetroTech Center, Brooklyn, New York 11201-3850.

## I. Introduction and Background

**Q. By whom are you employed and in what capacity?**

A. Subsequent to the acquisition of KeySpan Corporation by National Grid plc, I was named the Director of Service Company and Accounting Support for National Grid USA. I will assume that position upon the completion of the EnergyNorth Natural Gas, Inc. d/b/a National Grid NH ("National Grid NH" or the "Company") rate case. Currently, I am responsible for providing accounting and financial systems expertise in the preparation of various exhibits and analyses associated with the Company's cost of service and revenue requirement filings in this case.

**Q. Please briefly describe your educational background and business experience.**

A. I am a 1989 graduate of Long Island University at C.W. Post with a B.S. degree in Accounting and also hold an A.S. degree in Engineering Science and an A.A.S in Accounting from Suffolk County Community College. I am a Certified Public Accountant in the State of New York and a Member of the American Institute of Certified Public Accountants and the Institute of Internal Auditors.

From September 1989 until August 1993, I was employed as a Senior Auditor by Ernst and Young LLP. In August 1993, I joined The Long Island Lighting

Company ("LILCO") as a Principal Accountant in Regulatory and Financial Reporting and served in that capacity until May 1997 at which time I served as a member of the integration team working on the merger between LILCO and The Brooklyn Union Gas Company that resulted in the creation of KeySpan Corporation. Since that time, I have served in a number of positions and worked on a number of corporate strategic initiative teams within the KeySpan organization, including Senior Analyst for Financial Planning (1998-1999), Senior Analyst for Accounting Systems (1999-2000), Implementation Team Member for KeySpan's new Oracle Financial System (2000-2001), Manager of New Financial Systems Planning (2001-2002), Director of Internal Audit Services (2002-2005) where I assumed a lead role in the implementation of Sarbanes-Oxley compliance, and as a member of the KeySpan Energy Delivery New York and the KeySpan Energy Delivery Long Island Rate Case Team (2005-2007), a position I held until assuming my present responsibilities in the fall of 2007.

**Q. Have you previously testified before any regulatory agencies?**

A. I have testified before the New York State Public Service Commission in Docket 06-G-1185 (Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York for Gas Service) and Docket 06-G-1186 (Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island for Gas Service).

## II. Overview of Testimony

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to support the National Grid NH request in this proceeding to increase its overall revenue requirement by approximately $9.9 million. My testimony supports (i) the rate of return for the twelve months ended June 30, 2007, the test year in this case, (ii) the adjusted pro forma rate of return, (iii) an analysis of certain expense adjustments required to arrive at operating income for the rate year, including applying a $619,000 credit to reflect savings arising from the KeySpan-National Grid merger, (iv) historic data for the test year pertaining to operations and maintenance expenses, general taxes, rate base and income taxes, and (v) adjusted pro forma data and an analysis of certain adjustments related to that same data for the rate year for these costs. In addition, I will present National Grid NH's historic and pro-forma cost of long and short term debt, capital structure, and overall rate of return for the test year and a comparison of benefits to New Hampshire customers from the KeySpan/National Grid merger to those received by New York customers.

**Q. Are you sponsoring any exhibits as part of your filing?**

A. Yes. I am sponsoring the following exhibits that have been included in the rate case filing pursuant to Puc 1604.07 and 1604.08, which were prepared under my supervision and direction and which, in all instances, refer to EnergyNorth or National Grid NH (and is sometimes identified as Company 06):

**Exhibit EN 2-1:** Computation of Revenue Deficiency

**Exhibit EN 2-2:** Schedule 1 – Operating Revenues

**Exhibit EN 2-2-1:** Summary of Pro Forma Adjustments Income or Expense

**Exhibit EN 2-2-1A:** Attachment – Summary of Pro Forma Adjustments

**Exhibit EN 2-2-2:** Schedule 1A – O&M

**Exhibit EN 2-2-3:** Schedule 1B – Taxes Other Than Inc Taxes

**Exhibit EN 2-2-4:** Schedule 1C – Depreciation Expense

**Exhibit EN 2-2-5, p. 1:** Schedule 1D – Income Taxes – State Income Taxes

**Exhibit EN 2-2-5, p. 2:** Schedule 1D – Income Taxes – Federal Income Taxes

**Exhibit EN 2-3, p. 1:** Schedule 2A – Assets and Deferred Charges

**Exhibit EN 2-3, p. 2:** Schedule 2B – Stockholders Equity and Liabilities

**Exhibit EN 2-3, p. 3:** Schedule 2C – Materials and Supplies

**Exhibit EN 2-4:** Schedule 3 – Rate Base

**Exhibit EN 2-4-1:** Schedule 3A – Working Capital

I am also sponsoring the following schedules supporting the capital structure, cost of debt and the overall rate of return that were prepared by Andrew Dinkel, Director of Rate Case Management:

**Exhibit EN 3-1:** Overall Rate of Return

**Exhibit EN 3-2:** Capital Structure

**Exhibit EN 3-2A:** Capital Structure Excluding Goodwill

**Exhibit EN 3-3:** Historical Capital Structure

**Exhibit EN 3-4:** Capitalization Ratios

**Exhibit EN 3-5:** Weighted Average Cost of Long Term Debt

**Exhibit EN 3-6:** Cost of Short Term Debt

**Exhibit EN 3-7:** Cost of Common Equity

Finally, I am sponsoring Attachment JOS-1 (Accounting Code Block, Service Company Allocation Methodology and Service Company Allocation Example) and Attachment JOS-2 (which was prepared by Mr. James Molloy, the Director of Regulatory Compliance for National Grid USA Service Company, and compares the benefits of the National Grid/KeySpan merger to New York customers with the benefits to New Hampshire customers). Both of these documents are included at the end of my testimony.

**Q. Can you summarize the primary factors that have caused the Company to seek rate relief?**

A. The Company is seeking an increase in rates because it is earning significantly less than its allowed rate of return. As described in more detail below, the Company is earning almost 600 basis points below its last allowed return. This primarily results from the fact that rate base has more than doubled since the last general rate filing by the Company more than 15 years ago, including the addition of significant non-revenue producing assets during that time period. In addition, the Company's operating expenses have increased significantly. Over the past 15 years, inflation has increased nearly 50%. Not surprisingly, the Company has experienced increases in the cost of labor, benefits and most other operating expenses. This is further compounded by a decline in average use per customer as a result of customer conservation and energy efficiency improvements to homes and natural gas heating equipment.

**Q. Did the Company earn its allowed rate of return in the test year ended June 30, 2007?**

A. No. Exhibit EN 2-2-1A, which is submitted as part of the Company's filing, shows that the Company earned a rate of return of 3.94% for the test year ended June 30, 2007, which is substantially less than the last allowed overall rate of return of 9.83% and is also below the proposed rate of return in the Company's filing in this case (9.26%).

## III. Overview of Development of Operating Expenses Included in Revenue Requirement

**Q. Please summarize how the cost of service for National Grid NH was determined in this proceeding.**

A. The proposed revenue requirement is based on an historical test year, which is the twelve months ended June 30, 2007, and a pro forma test year (sometimes referred to as the rate year). There is one notable item reflected in this cost of service filing resulting from the National Grid/KeySpan merger. Pursuant to the EnergyNorth Merger Rate Agreement, approved in Order No. 24,777 dated July 12, 2007, National Grid NH, customers are provided with a $619,000 net synergy savings credit. The credit represents 50% of the estimate of net, steady state synergy savings from the merger allocable to National Grid NH. The $619,000 credit is reflected in the Company's cost of service as a pro forma reduction to test year operations and maintenance ("O&M") expenses, thereby allowing customers to realize the benefit of the savings immediately in the first year that new rates go into effect, rather than waiting until the synergy savings actually occur. It is also important to note that the expenses that are included for purposes of determining the Company's revenue requirement are comprised of both costs incurred directly by the Company and allocated costs incurred by its service company affiliates, which I will describe below. Thus, each cost component has a direct and an allocated cost portion. An explanation of the general ledger system, accounting code block, and allocation methods for allocated costs is set forth in Attachment JOS-1. Because the test year precedes the merger with National Grid, all of the allocated costs are from KeySpan service companies.

**Q. Please describe the KeySpan service company structure.**

A. Prior to the repeal of the Public Utilities Holding Company Act of 1935, ("PUHCA"), KeySpan was subject to the jurisdiction of the Securities Exchange Commission ("SEC") under PUHCA. As part of the regulatory provisions of PUHCA, the SEC regulated various transactions among affiliates within a holding company structure. In accordance with the regulations of PUHCA and New York State Public Service Commission requirements, KeySpan created three distinct service companies: (i) KeySpan Corporate Services, providing traditional corporate and administrative services; (ii) KeySpan Utility Services, providing gas and electric transmission and distribution systems planning, marketing, and gas supply planning and procurement; and (iii) KeySpan Engineering Services, providing engineering and surveying services to affiliates. All three companies are collectively referred to in this testimony as the KeySpan Service Companies. Allocation methodologies, approved by the SEC, have been in use since 2001 to allocate certain service company costs to affiliates.

## IV. Detailed Review of Operating Expense Exhibits

**Q. Please describe the data presented in Exhibit EN 2-1: Computation of Revenue Deficiency.**

A. This schedule presents the computation of the revenue deficiency and resultant increase in the base revenue requirement of $9,896,601, based on a proposed allowed rate of return of 9.26% on a rate base of $148,037,338.

**Q. Please describe the data presented in Exhibit EN 2-2-1: Summary of Pro Forma Adjustments Income or Expense.**

A. This schedule presents a summary of the pro forma adjustments to both revenues and expenses aggregated by cost of service category.

**Q. Please explain Exhibit EN 2-2-2.**

A. Exhibit EN 2-2-2 includes a summary schedule and 17 supporting schedules. It shows the test year O&M expenses as well as adjustments, where appropriate, for known and measurable changes and the comparable amounts as recorded in each of the two preceding fiscal years. The amounts presented on each of the schedules are compiled in two ways. The first presents the amounts aggregated by provider company. This allows the amounts allocated from each of the KeySpan Service Companies to be distinguished from the amounts generated directly within the utility. The second aggregates the amounts in accordance with the specific O&M account classifications, as prescribed in the FERC Chart of Accounts and as reflected in all of the former KeySpan entity's financial statements.

**Q. Please explain the specific schedules in Exhibit EN 2-2-2.**

A. The Summary Schedule shows total O&M expense for the historical test year of $156,342,800, and $159,649,786 after adjustment for known and measurable changes. The detailed schedules behind the summary are as follows:

**Schedule 1**

This schedule, consisting of two pages, presents the cost of gas purchased and produced for the historical test year and the pro forma test year. The second page summarizes the gas cost adjustments made to the per-books historical test year gas costs. The first column indicates the test year costs recorded on the Company's books. The second column, "Adjustment", includes a detailed list of all the adjustments made to the historical test year gas costs. These include a weather normalization adjustment, removal of certain gas costs including interruptible sales, off-system sales, and broker balancing charges, and various accounting adjustments (which include occupant account gas costs and the reallocation to gas costs of the portion of bad debt that is attributable to the gas supply function as well as production and storage credits from the operations and maintenance expense accounts). After these adjustments, EnergyNorth's total gas costs for the test year were $133,114,231. Additional details on the weather normalization and other adjustments contained in this schedule can be found in the prefiled direct testimony of Ann Leary.

**Schedule 2**

Schedule 2, consisting of eight pages, shows operating labor expense for the historical test year and the pro forma test year. The details of the calculation of the pro forma labor increase are shown on pages 2 through 8. Page 2 details the labor adjustments, which are broken down between union and management employees and by base pay increases versus variable compensation (for management) and gainsharing (for unions). Page 3 details the union wage adjustment. Because the utility and the service companies have different unions, and each company may also have multiple unions, we used the average union wage increase of 3.21% for National Grid NH, 5.14% for KeySpan Corporate Services, and 4.58% for KeySpan Utility Services. Page 4 adjusts management wages by 8.16%. Pages 5 through 8 detail the number of employees in each company (broken down between union and management), the average salary, the overall increase for management and union, and the composite increase used on pages 3 and 4.

**Q. Please explain how the overall increase for each union and for management was developed.**

A. The overall union increase was based on the actual contracted increase for each union. Each union has a different contract year and a different contractual increase. Management's overall composite increase of 8.16% results from two adjustments to normalize test year wages. Test year wages were normalized for 9/12 of the April 2007 merit increase of 4.55%, or 3.41%, to include nine months of the increase that was not included in the test year actuals and also for the merit increase of 4.75% that will take effect June 29, 2008 for employees of National Grid USA and its subsidiaries who were formerly KeySpan management employees. (This increase was made to bring the timing of raises for former KeySpan employees in line with annual raises for National Grid employees.)

**Q. Please return to Schedule 2, page 2, and explain the Union Gainsharing and Management Variable Compensation adjustments.**

A. The Company is requesting that "target" Variable Compensation and Gainsharing levels be included in rates. Under the Company's incentive compensation plans, target levels are established based on reasonable expectations of financial performance. However, actual payouts to employees can be higher or lower based on actual performance achieved during the year. In the instant case, the Company's actual performance and level of payout to employees was higher than the target and was clearly impacted by the merger. Thus, for ratemaking purposes we adjusted Variable Compensation and Gainsharing by decreasing the actual O&M expense to bring the expense level to target.

**Q. Please give one example of how this adjustment was made.**

A. The Management Variable Compensation for National Grid NH expense from KeySpan Corporate Services reduces the Company's O&M expense by $399,448, as shown on Exhibit EN 2-2-2, Schedule 2, page 2. The total KeySpan Corporate Services Variable Compensation accrued in the test year was $42,321,639, and the National Grid NH O&M allocation was 1.74% of that amount, or $736,361. The targeted Variable Compensation for KeySpan Corporate Services for the test year was $19,363,745. Therefore, National Grid NH's O&M was $399,448 (19,363,745 – 42,321,639 x 1.74%) higher than target. Thus, $399,448 was subtracted from the test year expense to arrive at the rate year expense.

**Q. Was the same adjustment made for each company, for both Union Gainsharing and Management Variable Compensation?**

A. Yes, while the percentage and amounts differ, all eight calculations follow the same method.

**Q. Please return to page 1 of Schedule 2 of Exhibit EN 2-2-2 and summarize the labor adjustment.**

A. Page 1 shows the total labor adjustment, which is a decrease of $24,279. Page 2 shows (i) the wage increase of $495,344, broken down by union (a $159,729 increase) and management (a $335,615 increase) (ii) the Variable Compensation adjustment (a $519,622 reduction), and (iii) the Gainsharing adjustment (a $20,297 reduction). The bottom of the page shows the total adjustment.

**Q. Please continue with your explanation of the schedules in Exhibit EN 2-2-2.**

**<u>Schedule 3</u>**

Schedule 3 shows the adjustments to contract labor expense. The pro-forma increase of $19,894 shown on Schedule 3-1 relates to paving expenses, which were $574,986 in the test year. The Company utilizes two outside firms – Brenton Contracting and R.H. White to perform paving. New contracts effective January 1, 2008 with Benton Contracting and R.H. White provide for a 3% and 3.5% increase, respectively. R.H White performs 92% of the paving work, with Benton Contracting providing the balance. The weighted average contractual increase in paving costs is 3.46%, which was applied to the test year paving costs. This resulted in the pro forma adjustment of $19,894. This was added to the total test year contract labor of $816,846, to yield the pro forma test year amount of $836,740.

**<u>Schedule 4</u>**

**Q. What does Schedule 4 show?**

A. This schedule, consisting of 2 pages, shows the health and hospitalization expense in the test year and the rate year. The health care percentage increases are shown on page 2. The percentage increases represent the overall composite rate increases for all medical and dental plans based on current premiums. The percentage increase in premiums experienced by each company was applied to the historical test year expenses to yield the adjustment of $206,116 to the test year amount.

**<u>Schedule 5</u>**

**Q. Please explain Schedule 5.**

A. Schedule 5 presents the historical test year balance of other employee related expenses and benefits of $351,854. These costs consist primarily of employee expense reimbursements for business related expenses. There are no adjustments to the test year amount.

**<u>Schedules 6 and 7</u>**

**Q. Please explain Schedules 6 and 7.**

A. Schedule 6 and Schedule 7 present the National Grid NH pension and post retirement benefits other than pensions ("OPEB") expenses of $1,782,213 and $1,111,404, respectively, for the 12 month historical test year period. As discussed below, the Company is requesting that the Commission authorize specific deferral accounting treatment, a reconciling mechanism, and the collection of deferred pension and OPEB's through the Company's local distribution adjustment charge ("LDAC"). Under the Company's proposal, the test year amount would be included in base rates, subject to a reconciling mechanism included in the LDAC.

**Q. Before describing the deferral accounting, reconciling mechanism and collection process, please explain why the Company is seeking special treatment for pension and OPEB expenses.**

A. Pension and OPEB expenses are a significant expense for the Company. The actual test year expense was $1,782,213 for pensions and $1,111,404 for OPEB's. The calculation of pension and OPEB expense is highly volatile and relies heavily on actuarial assumptions, and other factors beyond management's control to calculate the estimated cost of these benefits. Employee turnover, retirement age, life expectancies, administrative expenses of the pension plan, assumed earnings on plan assets, and the date on which a benefit becomes fully vested are some of the more important actuarial assumptions. Other factors such as the discount rate employed and fluctuations in the stock market together create many uncertainties in estimating pension and OPEB expenses. As a result, amounts recorded on a company's books for pension and OPEB's can and do vary significantly from year to year. Because of these circumstances, the Company is requesting the Commission to authorize an alternative ratemaking approach for pension and OPEB expenses than has been employed in the past.

**Q. How would the proposed reconciling mechanism work?**

A. The Company has included the historical test year pension expense of $1,782,213 and OPEB expense of $1,111,404 in the pro forma test year. Under the proposed reconciling mechanism, any difference between the actual amount of recorded FAS (Financial Accounting Standard) expense and the amount included in the pro forma test year would be deferred for later recovery from or credit to customers. The Company would calculate a carrying charge at the pre-tax weighted cost of capital and also defer that amount as well.

**Q. How do you propose the deferred amount be collected from or returned to customers?**

A. The December 31 balance, positive or negative, would be collected or refunded through the LDAC during the subsequent year beginning with the next Peak Period, when the LDAC is normally adjusted.

**Q. Please explain why this is beneficial to customers.**

A. As I stated, pension and OPEB expense has significant volatility and any amount included in the cost of service is just as likely to be overstated as understated. The Company's proposed reconciliation mechanism (1) would allow the Company to recover pension and OPEB costs incurred in providing service to customers and (2) would ensure that customers pay no more or less than the amounts needed to meet the Company's obligation to employees. A reconciling mechanism safeguards customers from inaccurate actuarial and health care cost assumptions and mitigates the volatility in rate and expense differences. This ultimately provides better matching between revenues and prudently incurred costs.

**Q. The EnergyNorth Merger Rate Agreement in Docket No. DG 06-107 contained a provision relating to a separate issue concerning pension and**

**OPEB expense. Can you explain how the Company is addressing this provision of that agreement?**

A. The Company was authorized to defer the recognition of any unrecognized gains or losses resulting from the fair market valuation of the assets in its pension and OPEB plans as of the closing date of the merger. The resulting regulatory liability or asset is to be amortized to expense over a period equal to the average estimated remaining service lives of the employees in the plan. In effect, the amortization of this regulatory asset or liability will become a component of net periodic expense for pension and OPEB's. The determination of the required deferral is pending as of the date of this filing, but is expected to be final by the Company's fiscal year end, March 31, 2008.

<u>Schedule 8</u>

Q. **Please return to your explanation of the schedules in Exhibit EN 2-2-2, beginning with Schedule 8.**

A. Schedule 8 adjusts the payroll taxes included in operation and maintenance expense by the composite wage increases in each company. Payroll taxes are included in operations and maintenance expenses, rather than taxes other than income taxes, because when labor expenses are allocated from the KeySpan Service Companies to National Grid NH all benefits, including payroll taxes, follow the labor. This ensures that all associated benefit costs are allocated correctly.

**Schedule 9**

**Q. Please summarize Schedule 9.**

A. In Schedule 9, test year expenses for purchased services of $2,672,261 were adjusted by $4,227 to $2,668,034 to remove costs incurred in connection with the Company's Petition for Increase in Short Term Debt Limit. As per the settlement in Docket DG 06-122, the Company agreed not to seek recovery of these costs from customers.

**Schedule 10**

**Q. Please explain Schedule 10.**

A. Schedule 10, postage, adjusts test year postage expense by $25,069, from $334,254 to $359,324, to reflect the increase in domestic postal rates put into effect on May 14, 2007 by the U.S. Postal Service.

**Schedule 11**

**Q. Please explain Schedule 11.**

A. Schedule 11 provides the level of contributions, tickets and sponsorships expenses, which have been eliminated from the operation and maintenance expenses, as shown on this schedule, and therefore are not included in the Company's cost of service.

**Schedule 12**

**Q. Please explain Schedule 12.**

A. Dues and memberships expenses are presented in this schedule. There is no pro forma adjustment to the test year amount of $46,464.

**Schedule 13**

**Q. What does Schedule 13 show?**

A. Schedule 13 shows "other expenses," which are comprised of numerous smaller dollar amounts that are aggregated and presented at their historical test year balances. Examples of the types of items included in this schedule include, among others, costs associated with building services, fleet, sales programs, advertising, and materials and supplies.

**Schedule 14**

**Q. What is shown on Schedule 14?**

A. Schedule 14 shows uncollectible expense of $3,693,923 for the test year, which is increased by $899,536 to $4,593,459. The increase results from applying the proposed uncollectible percentage of 2.54% (based on a three year average of net write-offs) to adjusted test year revenues of $180,859,381.

**Schedule 15**

**Q. What is shown on Schedule 15?**

A. This schedule presents an adjustment of $3,474,004 to reclassify to gas costs the gas cost portion of bad debt credits and production and storage credits that were recorded in the test year O&M accounts, as presented in Schedule 1. This adjustment is discussed in more detail in Ms. Leary's testimony.

**Schedule 16**

**Q. Please explain Schedule 16.**

A. Schedule 16 shows the incremental expense of $1,597,365 associated with the increased level of emergency response and collection activities undertaken or proposed to be undertaken by the Company.

**Q. Please describe the program changes associated with emergency response for National Grid NH.**

A. The Company has implemented changes to its emergency response time standards to respond to emergency calls when the caller is reporting a gas leak or gas odor. These changes are consistent with Section 7(N) on pages 16-19 of the EnergyNorth Merger Rate Agreement approved in Commission Order No. 24,777. The expenses shown in Schedule 16-1 and Schedule 16-2 are fully incremental to the test year and reflect the direct labor, labor burdens and non-labor costs associated with one supervisor and six technicians that have been added to the workforce as of September 1, 2007.

**Q. Please describe the proposed program changes associated with collection cost activities for the Company.**

A. On November 11, 2007, the Company, the PUC Staff and the Office of Consumer Advocate entered into a partial settlement, which included a requirement that the Company file a written plan setting forth its proposed collections process on a going-forward basis for review by Staff. The settlement further provided that the prudently incurred costs of the collections process described in the plan (including, on an annualized basis, any costs that are incremental to those reflected in the Company's test year) shall be recoverable through the rates set in this case. The Company's anticipated incremental costs associated with this plan—increased field collection employees, associated non-labor costs, reconnection costs associated with increased number of customer accounts locked for non-payment, increased customer calls to the contact center and increased postage associated with notices—are detailed in Schedule 16-3. The changes to the Company's collections process that resulted in these additional costs are addressed in the testimony of Mr. Gary Bennett.

**Schedule 17**

**Q. Please explain Schedule 17.**

A. This schedule details the $619,000 credit that has been applied as a direct reduction to operations and maintenance expenses in the pro forma test year, as provided for in the merger rate agreement.

**Q. Please explain Exhibit EN 2-2-3, Taxes Other Than Income Taxes.**

A. Below I have summarized the methods used to pro form the rate year tax expenses shown on Exhibit EN 2-2-3.

Real Estate Taxes - The pro forma amount presented for real estate taxes was based on the actual taxes paid using the latest known latest bills received through January 2008.

Federal FICA Taxes and Federal and State Unemployment Taxes - Payroll-based taxes have been adjusted based on the overall payroll increase for the Company.

Other State Taxes and Capitalized Payroll Taxes – These taxes are presented at their historical test year amounts and do not have pro forma adjustments.

**Q. Please explain Exhibit EN 2-2-4.**

A. This schedule shows the total booked depreciation expense of $8,824,109 for the test year, which was reduced by $1,053,408 to $7,770,701 for the pro forma test year. This $1,053,408 adjustment reflects the adoption of the recommendations presented in the depreciation study of Company witness Paul M. Normand based on the December 31, 2006 plant balances.

**Q. Please explain the data and calculations for Exhibit EN 2-2-5, page 1 (State Income Taxes), and Exhibit EN 2-2-5, page 2 (Federal Income Taxes), and page 3 of EN 2-2-5 (Computation of Utility Interest Deduction).**

A. Exhibit EN 2-2-5, page 1, presents the pro forma state income tax expense. The expense is calculated by applying the statutory rate of 8.50% to the Operating Income before Income Taxes & Interest Charges, as shown on Exhibit EN 2-2-1, less the interest deduction shown on page 3 and net flow-through additions and deductions.

Exhibit EN 2-2-5, page 2, presents the pro forma federal income tax expense and is calculated by applying the statutory rate of 35% to the Operating Income before Income Taxes, as shown on Exhibit EN 2-2-1, less the interest deductions, the net flow-through additions and deductions and the state income tax expense shown on Exhibit EN 2-2-5, page 1.

Exhibit EN 2-2-5, pages 1 and 2, also detail the current and deferred income tax expense. The current income tax expense is computed by applying the statutory rates to the current taxable income. The deferred income tax expense is computed by applying the statutory rates to the amounts in the section labeled Timing Differences.

Page 3 of Exhibit EN 2-2-5 computes the pro forma test year interest expense that is used in the income tax calculations. The interest expense is derived by multiplying the rate base as shown on Exhibit EN 2-4 times the interest component of the rate of return shown on Exhibit EN 3-1.

## V. Development of Rate Base

**Q. Please describe Exhibit EN 2-3.**

A. Page 1 of this exhibit presents the balance sheet for assets and deferred charges for the historical test year and the two preceding fiscal years, as well as the thirteen month average balances for the historical test year. Page 2 presents the same information for stockholders equity and liabilities. Page 3 presents the same information for materials and supplies.

**Q. Please describe Exhibit EN 2-4: Schedule 3, and how the Company arrived at its test year rate base figure.**

A. Schedule 3 shows the amounts for each of the thirteen points from July 1, 2006 to June 30, 2007 for total gas plant (plant in service and completed construction not classified), non-interest bearing CWIP, and the accumulated reserve for depreciation.

Page 2 of Exhibit EN 2-4 summarizes the adjustments to the property base (or rate base). The first adjustment to rate base is an addition of $4,170,788, representing deferred regulatory costs, comprised predominantly of $2.7 million related to FAS 109 deferrals and $1.4 million of deferrals associated with gas jobs in progress. The monthly balances can be found on page 3 of this schedule. The second adjustment is a reduction of $41,047,029, relating to deferred federal and state income taxes. These taxes primarily reflect the effects of the timing differences related to accelerated depreciation methodologies between the book and tax returns, cost of removal, unamortized investment tax credits and the timing differences of other net costs of the Company. These monthly balances are reflected on page 4.

Schedule 3A, "Working Capital", shows the derivation of the total working capital allowance of $7,092,752, which has been included as an addition to the average test year rate base. Cash working capital is made up of two components, prepayments and a cash working capital allowance, as shown on page 1. Pages 2 and 3 of Schedule 3A present the details of the average balances of these amounts. For purposes of determining the non-gas related cash working capital allowance, the traditional one-seventh of net O&M expense was applied. For gas related cash working capital, a 12.04 day lag was used. The source of the 12.04 day lag was the lead/lag study prepared under the direction of Mr. Goble. I should note that Mr. Goble will also be completing a lead/lag study to develop non-gas cash working capital, and will be supplying supplemental testimony discussing it shortly after this filing is made. To the extent that the results of Mr. Goble's work differ from the results of the methodology used by the Company in this filing, the Company will update its revenue requirement as appropriate.

The net effect of all of these adjustments to property base and working capital is shown an adjusted average rate base for the test year of $148,037,338.

## VI. Rate of Return

**Q. What is the overall rate of return that the Company is proposing?**

A. The Company is proposing an overall rate of return of 9.26%, as shown on Exhibit EN 3-1. This is based on a capitalization ratio of 50% long-term debt and 50% equity, a long-term debt cost rate of 7.02% (yielding a weighted average cost for long-term debt of 3.51%), and a common equity cost rate of 11.5% (yielding a weighted average cost for common equity of 5.75 %). The sum of the weighted average costs of equity and long-term debt equals the overall rate of return of 9.26%.

**Q. How did you determine the capitalization ratios that you used?**

A. The capital structure used by the Company was dictated by the EnergyNorth Merger Rate Agreement approved in Docket No. DG 06-107, which stipulated that in this rate filing the Company would be required to use a debt to equity ratio of 50/50 for determining its overall rate of return. In addition, as a result of the settlement reached in Docket DG 06-122, all of the short-term debt outstanding as of June 30, 2007 will be refinanced with long-term debt prior to June 30, 2008, and therefore the cost rate of the debt portion of the Company's capital structure for this case is equal to the cost of its outstanding long-term debt.

**Q. Are there any other issues you would like to address concerning the capital structure used to determine the overall rate of return for National Grid NH?**

A. Yes. Schedule EN 3-2A shows the Company's capital structure at June 30, 2007, excluding the goodwill recorded on the Company's books at that time. As the schedule shows, after removing the goodwill from the Company's equity, the common equity ratio at the end of the test year was 52.3%. The 50% equity ratio dictated by the Merger Rate Agreement is below this amount and is thus appropriate for establishing the overall rate of return in this proceeding.

**Q. How was the weighted average cost of long-term debt shown on Exhibit EN 3-5 calculated?**

A. The settlement in DG 06-122 specifies the weighted average cost of long-term debt to be used in the determination of the Company's revenue requirement in this rate case filing. Schedule EN 3-5 replicates a portion of Exhibit 4 in Docket DG 06-122, which shows the calculation of the weighted average cost of long-term debt.

Q. **What pro forma adjustments were made to the balance of short-term debt that was outstanding during the test year?**

A. As noted above, the balance of short-term debt outstanding during the test year will be eliminated by the refinancing to be undertaken in accordance with the settlement in Docket DG 06-122.

**Q. What cost rate did the Company use for the common equity component of its capital structure?**

A. The Company is using a return on equity of 11.5%, as discussed in the testimony of Mr. Moul.

## VII. Comparison of Merger Benefits To New York

**Q. Did the Company perform a comparison of the benefits from the National Grid/KeySpan merger to New Hampshire customers with the benefits to New York customers, as required by the EnergyNorth Merger Rate Agreement?**

A. Yes. Section 4 of the EnergyNorth Merger Rate Agreement requires the Company to perform an economic analysis to show whether the total economic benefits being provided to the Company's customers are at least equal to or better than the total economic benefits provided to New York customers. That analysis is set forth on Attachment JOS-2, and provides the basis for the Company's conclusion that no further adjustment to rates is required under the agreement.

**Q. Does this conclude your testimony?**

A. Yes.

**Q. Identify KeySpan's General Ledger System**

A. KeySpan is operating Oracle General Ledger 11i, Version 11.5.7+. Oracle General Ledger is the central repository for accounting information and receives transactions from both Oracle and non-Oracle subledgers.

**Q. Describe KeySpan's General Ledger Accounting Code block**

A. KeySpan's G/L code block is comprised of eight independent segments that together comprise what is defined as an Accounting Flexfield. A visual description of the Accounting Flexfield is presented below where x represents the number of digits contained in each segment:

| Segment 1 | Segment 2 | Segment 3 | Segment 4 | Segment 5 | Segment 6 | Segment 7 | Segment 8 |
|---|---|---|---|---|---|---|---|
| RCO xx | RCC xxx | Activity xxxxxx | Cost Type xxx | Account xxxxx | Project xxxxxx | PCC xxx | PCO xx |

<u>**Segment Descriptions:**</u>

**RCO (Receiver Company):** This segment is used to identify which Company's set of books is recording the transaction

**RCC (Receiver Cost Center):** identifies the specific responsibility/cost center being charged

**Activity:** The activity segment is used to provide/describe some specifics or details of the transaction being recorded. Although each segment in the Flexfield is defined as independent from a system perspective, which is to say, that Oracle does not enforce any rules with respect to the relationship between one segment and any other or others, in practice, an Activity segment is subordinate to the Project segment and is used to further define or segregate the detail provided by the Project segment.

**Cost Type:** This segment is used to identify the lowest level of resource provided/expended in the transaction

**Account:** This segment is used to identify the appropriate General Ledger Account in accordance with the FERC chart of accounts

**Project:** Similar to the Activity segment described above, the project segment is used to provide/describe some specifics/details of the transaction being recorded. In practice, the Project segment is often hierarchically superior to the activity segment and most times will identify a broad category which is then further defined/described by one or more activities.

**PCC (Provider Cost Center):** This segment identifies the specific cost center providing the charge

**PCO (Provider Company):** This segment identifies the Company providing the charge in the transaction. It is also referred to as the "Intercompany" Segment due to the fact that a flexfield containing a PCO segment value that does not match the RCO segment value identifies a transaction that has occurred between two companies.

**Q. Explain KeySpan's Service Company Structure**

**A.** Prior to the repeal of the Public Utilities Holding Company Act of 1935, (PUHCA), KeySpan was subject to the jurisdiction of the SEC under PUHCA. As part of the regulatory provisions of PUHCA, the SEC regulates various transactions among affiliates within a holding company structure. In accordance with the regulations of PUHCA and the New York State Public Service Commission requirements, KeySpan created three distinct service companies:(i)**KeySpan Corporate Services**, *(Oracle company segment-31)* providing traditional corporate and administrative services; (ii) **KeySpan Utility Services**, *(Oracle Company Segment-32)*,providing gas and electric transmission and distribution systems planning, marketing, and gas supply planning and procurement; and (iii) **KeySpan Engineering Services**, *(Oracle Company Segment-33)*, providing engineering and surveying services to subsidiaries. All three companies are collectively referred to as the KeySpan Service Company. Allocation methodologies, approved by the SEC, have been in use since 2001 to allocate certain service company costs to affiliates.

**Q. How were the Components of Operating Expenses as presented in Exhibit 4 of the Stand-Alone Costs of Service defined?**

**A.** Each of the components depicted in the Summary of Operating Expenses is defined by the combination of the Cost Type and the G/L Account segments in the Accounting Flexfield. This combination of segments provides the best means for identifying the underlying elements of cost. Each unique Cost type/Account combination charged to O&M accounts in our historical test year ended 06/30/2007 was assigned to one of the Cost Component categories depicted on Exhibit EN 2-2-2 Schedule 1A - O&M.

**Q. Explain the format used to present the detail of Operating Expenses by Component for schedules 1-17 in Exhibit EN 2-2-2 Schedule 1A - O&M.**

**A.** There are separate schedules for each of the Cost Components listed in the Exhibit 4 - Summary schedule. The amounts presented on each of the schedules are compiled in two ways. The first, presents the amounts aggregated by Provider Company. This allows the amounts allocated from each of the KeySpan Service Companies to be distinguished from the amounts generated directly within the utility company.

The second aggregates the amounts in accordance with the specific O&M account classifications as prescribed in the FERC Chart of Accounts.

**Q. How are Service Company costs recorded?**

**A.** All costs incurred by the KeySpan Service Companies are recorded on their own respective set of books.

**Q. How are the Service Company costs allocated?**

**A.** The process of allocating Service Company costs to operating companies is accomplished using advanced functionality contained in Oracle General Ledger. Oracle G/L contains a fully automated, rule driven allocation process known as "Mass Allocations" that is executed each month as a normal recurring job routine in the monthly closing cycle.

**Q. Please explain Oracle's Mass Allocation Process**

**A.** Generally, Oracle's Mass Allocation process applies pre-defined allocation rules designed to:(i) aggregate Service Company costs into "cost pools", (ii) calculate the amounts allocable to each operating company and (iii) generate and post all required journal entries.

**Q. Please explain the allocation rule designed to aggregate Service Company costs into "cost pools"?**

**A.** A Service Company cost pool is defined as the aggregation of all charges having a unique Cost Center, Project, Activity and G/L account code combination. This combination of account code segments represents the best level of detail for identifying an allocable cost and assigning an appropriate allocation code.

**Q. Please explain the allocation rule designed to calculate the amounts allocable to each operating company.**

**A.** Each Service Company cost pool, defined above, is assigned a specific "allocation code". An allocation code identifies the basis used to allocate, the mix of operating companies receiving the allocation and the percentage distribution applicable to each operating company. Allocation codes are designed to produce reasonable and consistent results and are assigned to cost pools in a manner consistent with the cost causation principles of sound cost allocation theory. Our cost pools are specifically designed to maximize the assignment of direct allocation codes, (i.e. codes allocating 100% of the cost pool to a single operating company) and facilitate the assignment of indirect allocation codes that are based on the most appropriate cost causation method (i.e. number of employees, Massachusetts formula, number of meters, etc.)

**Q. How are allocated Service Company costs recognized in the operating companies sets of books?**

**A.** Allocated Service Company costs will have a Service Company segment value in the Provider Company segment and a Service Company Cost Center in the Provider Cost Center segment of the accounting Flexfield. The Accounting Flexfield will also contain the Project, Activity, and Cost Type of the original Service Company charge. For every charge, there is also a corresponding Intercompany entry.

**Q. Please provide an example of a specific Corporate Service Allocation**

**A.** The following example is intended to illustrate the logic and mechanics inherent in KeySpan's Service Company allocation process.

A Service Company Cost Pool associated with KeySpan's Financial Reporting function was chosen to illustrate our example.

Pertinent Service Company Cost Pool information is contained in the following tables:

| | Code Block Segment | Segment Value | Segment Value Description |
|---|---|---|---|
| Service Company Cost Pool | Company: | 31 | KEYSPAN CORPORATE SERVICES |
| | Cost Center: | 015 | FINANCIAL REPORTING ASSISTANT CONTROLLER |
| | Project: | K00036 | FINANCIAL RPT/RSCH |
| | Activity: | 002744 | FINANCIAL REPORTING ACTIVITY |
| | G/L Account: | 92000 | A&G-ADMIN & GEN SALARIES |

| Cost Period | Aggregate Charges |
|---|---|
| Annual | $853,319.58 |

The Allocation Code assigned to the example above is "G08". The Allocation Code contains the following intelligence: The Alpha character "G" indicates that the basis of allocation was determined by the Massachusetts Formula.

The remaining numeric digits, "08" identify the mix of companies receiving allocation. "08" = All Companies including the KSE Holding Company.

The combination of "G08" therefore applies the percentages calculated from the Massachusetts formula across the company mix represented by "All companies including the KSE Holding Company."

The Allocation percentages for Allocation Code G08 in effect during the example year are identified in the following table:

| Company | Company Description | Alloc. % |
|---|---|---|
| 01 | BOSTON GAS COMPANY | 13.1% |
| 03 | Colonial Lowell Division | 3.0% |
| 06 | EnergyNorth Company | 1.6% |
| 34 | KEYSPAN ELECTRIC SERVICES, LLC | 20.7% |
| 35 | KEYSPAN GENERATION SERVICES,LLC | 6.1% |
| 36 | KEYSPAN ENERGY DEVELOPMENT | 0.8% |
| 37 | KEYSPAN ENERGY DELIVERY LI | 13.0% |
| 38 | KEYSPAN ENERGY DELIVERY NY | 22.1% |
| 42 | KEYSPAN RAVENSWOOD SERVICES, LLC | 9.0% |
| 44 | KEYSPAN ENERGY TRADING SERVICES, LLC | 0.3% |
| 46 | KEYSPAN GLENWOOD ENERGY CENTER LLC | 0.4% |
| 48 | KEYSPAN PORT JEFFERSON ENERGY CENTER LLC | 0.4% |
| 57 | KEYSPAN ENERGY SERVICES INC. | 0.5% |
| 58 | KEYSPAN ENERGY SUPPLY INC. | 0.2% |
| 59 | KEYSPAN SERVICES INC | 4.0% |
| 60 | KEYSPAN ENERGY CORP | 3.8% |
| 71 | SENECA UPSHUR PETROLEUM | 1.0% |
| | Total | 100.0% |

As a result, the Financial Reporting Cost Pool is distributed across the operating companies in accordance with the assigned allocation percentages represented by Allocation Code G08 as illustrated below:

| Co | Company Description | Alloc % | Alloc $ |
|---|---|---|---|
| 01 | BOSTON GAS COMPANY | 13.1% | $111,784.86 |
| 03 | Colonial Lowell Division | 3.0% | $25,599.59 |
| 06 | EnergyNorth Company | 1.6% | $13,653.11 |
| 34 | KEYSPAN ELECTRIC SERVICES, LLC | 20.7% | $176,637.15 |
| 35 | KEYSPAN GENERATION SERVICES,LLC | 6.1% | $52,052.49 |
| 36 | KEYSPAN ENERGY DEVELOPMENT | 0.8% | $6,826.56 |
| 37 | KEYSPAN ENERGY DELIVERY LI | 13.0% | $110,931.73 |
| 38 | KEYSPAN ENERGY DELIVERY NY | 22.1% | $188,583.63 |
| 42 | KEYSPAN RAVENSWOOD SERVICES, LLC | 9.0% | $76,798.76 |
| 44 | KEYSPAN ENERGY TRADING SERVICES, LLC | 0.3% | $2,559.96 |
| 46 | KEYSPAN GLENWOOD ENERGY CENTER LLC | 0.4% | $3,413.28 |
| 48 | KEYSPAN PORT JEFFERSON ENERGY CENTER LLC | 0.4% | $3,413.28 |
| 57 | KEYSPAN ENERGY SERVICES INC. | 0.5% | $4,266.60 |
| 58 | KEYSPAN ENERGY SUPPLY INC. | 0.2% | $1,706.64 |
| 59 | KEYSPAN SERVICES INC | 4.0% | $34,132.78 |
| 60 | KEYSPAN ENERGY CORP | 3.8% | $32,426.14 |
| 71 | SENECA UPSHUR PETROLEUM | 1.0% | $8,533.20 |
| | Total | 100.0% | $853,319.58 |

## ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
### Economic Analysis of Customer Benefits
Summary

| Applying New York Structure | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 EnergyNorth Synergies | 627,517 | 857,611 | 1,098,813 | 1,351,534 | 1,385,322 | 1,419,955 | 1,455,454 | 1,491,841 | 1,529,137 | 1,567,365 |
| 2 EnergyNorth CTA | (1,232,429) | (489,898) | (480,292) | (217,092) | (232,781) | (191,156) | (148,250) | (67,881) | (69,802) | (72,044) |
| 3 NPV @ Pre-tax WACC | (2,461,739) | | | | | | | | | |
| 4 Levelized | (397,716) | (397,716) | (397,716) | (397,716) | (397,716) | (397,716) | (397,716) | (397,716) | (397,716) | (397,716) |
| 5 Net Synergies | 229,801 | 459,895 | 701,097 | 953,819 | 987,607 | | | | | |
| 6 NPV @ Pre-tax WACC | 2,393,185 | | | | | | | | | |
| 7 Levelized | 628,577 | | | | | | | | | |
| 8 Share of Net Synergies | 314,288 | 314,288 | 314,288 | 314,288 | 314,288 | 1,022,240 | 1,057,739 | 1,094,125 | 1,131,421 | 1,169,650 |
| 9 Efficiencies | 110,097 | 251,725 | 323,370 | 374,085 | 417,160 | 427,589 | 438,279 | 449,236 | 460,467 | 471,978 |
| 10 Customer Share applying NY Structure | 424,385 | 566,013 | 637,659 | 688,373 | 731,448 | 1,449,829 | 1,496,017 | 1,543,361 | 1,591,888 | 1,641,628 |
| 11 NPV of Customer Benefit | $5,926,111 | | | | | | | | | |
| 12 WACC | 9.83% | | | | | | | | | |

| New Hampshire Rate Agreement | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| 13 EnergyNorth Rate Base | 148,037,338 | | | | | | | | | |
| 14 Allowed Return | 9.83% | | | | | | | | | |
| 15 Current Return | 3.94% | | | | | | | | | |
| 16 Lost Return | 5.89% | | | | | | | | | |
| 17 Avoided Rate Increase for 1 Year | 8,718,827 | | | | | | | | | |
| 18 Agreed Customer Credit in 1st COS | | 619,000 | 619,000 | 619,000 | 619,000 | | | | | |
| 19 Cust. Shr. of Yr 5 Synergy Demonstration | | | | | | 724,914 | 748,009 | 771,680 | 795,944 | 820,814 |
| 20 Total Cust Benefit NH Rate Agreement | 8,718,827 | 619,000 | 619,000 | 619,000 | 619,000 | 724,914 | 748,009 | 771,680 | 795,944 | 820,814 |
| 21 NPV of Customer Benefit | $11,560,793 | | | | | | | | | |

1 Page 2, Line 8
2 Page 2, Line 25
3 NPV Line 2 using a discount rate equal to Line 12
4 Payment amortization over ten years of Line 3 with a discount rate equal to Line 12
5 Line 1 + Line 4
6 NPV Line 5 using a discount rate equal to Line 12
7 Payment amortization over five years of Line 6 with a discount rate equal to Line 12
8 First five years 50% of Line 7, next five years Line 1 + Line 4
9 Page 6 Line 11 * 1,000,000
10 Line 8 + Line 9
11 NPV Line 10 using a discount rate equal to Line 12
12 Page 18 of Commission Order No 20776 (DR 91-212)
13 Exhibit EN 2-1 First Line
14 Page 18 of Commission Order No 20776 (DR 91-212)
15 Exhibit EN 2-2-1
16 Line 14 - Line 15
17 Line 13 * Line 16
18 Rate Plan Settlement Section 1.C.
19 First five years 0, next five years 50% Line 10
20 Line 17 + Line 18 + Line 19
21 NPV Line 20 using a discount rate equal to Line 12

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH

## Economic Analysis of Customer Benefits

Illustrative Calculation of Synergy Value - Net Synergy by Year

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SYNERGIES (Page 3 Column C Times Page 5 Column B) | | | | | | | | | | | |
| 1 Massachusetts Electric | 7,743,831 | 10,583,289 | 13,559,831 | 16,678,519 | 17,095,482 | 17,522,869 | 17,960,941 | 18,409,964 | 18,870,213 | 19,341,969 | 157,766,909 |
| 2 Nantucket Electric | 94,635 | 129,335 | 165,710 | 203,823 | 208,918 | 214,141 | 219,495 | 224,982 | 230,606 | 236,372 | 1,928,016 |
| 3 New England Power | 2,781,089 | 3,800,840 | 4,869,824 | 5,989,857 | 6,139,603 | 6,293,094 | 6,450,421 | 6,611,681 | 6,776,973 | 6,946,398 | 56,659,781 |
| 4 Essex Gas | 425,693 | 581,783 | 745,409 | 916,849 | 939,770 | 963,265 | 987,346 | 1,012,030 | 1,037,331 | 1,063,264 | 8,672,740 |
| 5 Colonial Gas | 1,423,844 | 1,945,930 | 2,493,221 | 3,066,649 | 3,143,315 | 3,221,898 | 3,302,445 | 3,385,006 | 3,469,632 | 3,556,372 | 29,008,313 |
| 6 Boston Gas | 5,103,623 | 6,974,987 | 8,936,696 | 10,992,088 | 11,266,890 | 11,548,563 | 11,837,277 | 12,133,209 | 12,436,539 | 12,747,452 | 103,977,324 |
| 7 Granite State Electric | 329,506 | 450,327 | 576,981 | 709,683 | 727,425 | 745,611 | 764,251 | 783,357 | 802,941 | 823,015 | 6,713,095 |
| 8 EnergyNorth Gas | 627,517 | 857,611 | 1,098,813 | 1,351,534 | 1,385,322 | 1,419,955 | 1,455,454 | 1,491,841 | 1,529,137 | 1,567,365 | 12,784,550 |
| 9 Niagara Mohawk Electric | 15,772,131 | 21,555,354 | 27,617,780 | 33,969,720 | 34,818,963 | 35,689,437 | 36,581,673 | 37,496,215 | 38,433,620 | 39,394,461 | 321,329,355 |
| 10 Niagara Mohawk Gas | 4,067,331 | 5,558,713 | 7,122,097 | 8,760,141 | 8,979,144 | 9,203,623 | 9,433,713 | 9,669,556 | 9,911,295 | 10,159,077 | 82,864,690 |
| 11 BUG | 10,608,734 | 14,498,676 | 18,576,418 | 22,848,893 | 23,420,115 | 24,005,618 | 24,605,759 | 25,220,903 | 25,851,425 | 26,497,711 | 216,134,252 |
| 12 LILCO - GAS | 6,298,881 | 8,608,514 | 11,029,652 | 13,566,412 | 13,905,573 | 14,253,212 | 14,609,542 | 14,974,781 | 15,349,150 | 15,732,879 | 128,328,596 |
| 13 LIPA | 14,832,266 | 20,270,865 | 25,972,031 | 31,945,457 | 32,744,093 | 33,562,696 | 34,401,763 | 35,261,807 | 36,143,352 | 37,046,936 | 302,181,268 |
| 14 Unregulated | 2,454,541 | 3,354,556 | 4,298,023 | 5,286,545 | 5,418,709 | 5,554,176 | 5,693,031 | 5,835,356 | 5,981,240 | 6,130,771 | 50,006,949 |
| 15 Narragansett | 3,121,322 | 4,265,828 | 5,465,589 | 6,722,645 | 6,890,711 | 7,062,979 | 7,239,553 | 7,420,542 | 7,606,055 | 7,796,207 | 63,591,430 |
| 16 Providence Gas | 2,315,055 | 3,163,925 | 4,053,776 | 4,986,123 | 5,110,776 | 5,238,546 | 5,369,509 | 5,503,747 | 5,641,341 | 5,782,374 | 47,165,172 |
| 17 Total | 78,000,000 | 106,600,533 | 136,581,851 | 167,994,938 | 172,194,811 | 176,499,681 | 180,912,173 | 185,434,978 | 190,070,852 | 194,822,623 | 1,589,112,440 |
| COST TO ACHIEVE (Page 4 Column C Times Page 5 Column A) | | | | | | | | | | | |
| 18 Massachusetts Electric | (15,208,706) | (6,045,550) | (5,927,009) | (2,679,008) | (2,872,624) | (2,358,950) | (1,829,470) | (837,684) | (861,392) | (889,051) | (39,509,445) |
| 19 Nantucket Electric | (185,860) | (73,881) | (72,432) | (32,739) | (35,105) | (28,828) | (22,357) | (10,237) | (10,527) | (10,865) | (482,832) |
| 20 New England Power | (5,461,994) | (2,171,175) | (2,128,603) | (962,128) | (1,031,663) | (847,184) | (657,029) | (300,843) | (309,357) | (319,290) | (14,189,265) |
| 21 Essex Gas | (836,051) | (332,335) | (325,819) | (147,270) | (157,913) | (129,676) | (100,569) | (46,049) | (47,352) | (48,873) | (2,171,908) |
| 22 Colonial Gas | (2,796,397) | (1,111,584) | (1,089,788) | (492,584) | (528,184) | (433,736) | (336,381) | (154,023) | (158,383) | (163,468) | (7,264,529) |
| 23 Boston Gas | (10,023,398) | (3,984,359) | (3,906,235) | (1,765,618) | (1,893,222) | (1,554,681) | (1,205,724) | (552,081) | (567,706) | (585,935) | (26,038,961) |
| 24 Granite State Electric | (647,141) | (257,242) | (252,199) | (113,994) | (122,232) | (100,375) | (77,845) | (35,644) | (36,653) | (37,830) | (1,681,155) |
| 25 EnergyNorth Gas | (1,232,429) | (489,898) | (480,292) | (217,092) | (232,781) | (191,156) | (148,250) | (67,881) | (69,802) | (72,044) | (3,201,625) |
| 26 Niagara Mohawk Electric | (30,976,101) | (12,313,181) | (12,071,746) | (5,456,429) | (5,850,773) | (4,804,555) | (3,726,146) | (1,706,140) | (1,754,427) | (1,810,762) | (80,470,262) |
| 27 Niagara Mohawk Gas | (7,988,144) | (3,175,334) | (3,113,072) | (1,407,109) | (1,508,802) | (1,239,003) | (960,902) | (439,981) | (452,433) | (466,961) | (20,751,740) |
| 28 BUG | (20,835,309) | (8,282,157) | (8,119,762) | (3,670,132) | (3,935,378) | (3,231,665) | (2,506,300) | (1,147,593) | (1,180,072) | (1,217,964) | (54,126,334) |
| 29 LILCO - GAS | (12,370,857) | (4,917,488) | (4,821,067) | (2,179,122) | (2,336,610) | (1,918,785) | (1,488,103) | (681,377) | (700,662) | (723,160) | (32,137,231) |
| 30 LIPA | (29,130,229) | (11,579,436) | (11,352,388) | (5,131,280) | (5,502,124) | (4,518,251) | (3,504,104) | (1,604,471) | (1,649,880) | (1,702,858) | (75,675,021) |
| 31 Unregulated | (4,820,662) | (1,916,241) | (1,878,668) | (849,158) | (910,528) | (747,710) | (579,882) | (265,518) | (273,033) | (281,800) | (12,523,202) |
| 32 Narragansett | (6,130,204) | (2,436,792) | (2,389,012) | (1,079,833) | (1,157,874) | (950,827) | (737,408) | (337,647) | (347,203) | (358,352) | (15,925,153) |
| 33 Providence Gas | (4,546,715) | (1,807,346) | (1,771,908) | (800,902) | (858,785) | (705,219) | (546,929) | (250,430) | (257,517) | (265,786) | (11,811,538) |
| 34 Total | (153,190,200) | (60,894,000) | (59,700,000) | (26,984,400) | (28,934,600) | (23,760,600) | (18,427,400) | (8,437,600) | (8,676,400) | (8,955,000) | (397,960,200) |
| NET SYNERGIES (Synergies Plus Cost To Achieve) | | | | | | | | | | | |
| 35 Massachusetts Electric | (7,464,875) | 4,537,740 | 7,632,822 | 13,999,511 | 14,222,858 | 15,163,919 | 16,131,471 | 17,572,280 | 18,008,821 | 18,452,917 | 118,257,464 |
| 36 Nantucket Electric | (91,226) | 55,454 | 93,278 | 171,083 | 173,813 | 185,313 | 197,137 | 214,745 | 220,080 | 225,507 | 1,445,184 |
| 37 New England Power | (2,680,905) | 1,629,666 | 2,741,221 | 5,027,729 | 5,107,941 | 5,445,910 | 5,793,392 | 6,310,839 | 6,467,617 | 6,627,107 | 42,470,516 |
| 38 Essex Gas | (410,358) | 249,448 | 419,590 | 769,579 | 781,857 | 833,589 | 886,777 | 965,981 | 989,978 | 1,014,391 | 6,500,832 |
| 39 Colonial Gas | (1,372,553) | 834,346 | 1,403,433 | 2,574,064 | 2,615,131 | 2,788,162 | 2,966,064 | 3,230,983 | 3,311,249 | 3,392,904 | 21,743,784 |
| 40 Boston Gas | (4,919,775) | 2,990,627 | 5,030,462 | 9,226,470 | 9,373,669 | 9,993,881 | 10,631,552 | 11,581,127 | 11,868,833 | 12,161,517 | 77,938,363 |
| 41 Granite State Electric | (317,636) | 193,084 | 324,782 | 595,689 | 605,193 | 645,236 | 686,406 | 747,713 | 766,288 | 785,185 | 5,031,940 |
| 42 EnergyNorth Gas | (604,912) | 367,713 | 618,521 | 1,134,442 | 1,152,541 | 1,228,799 | 1,307,204 | 1,423,960 | 1,459,334 | 1,495,321 | 9,582,925 |
| 43 Niagara Mohawk Electric | (15,203,970) | 9,242,172 | 15,546,034 | 28,513,291 | 28,968,190 | 30,884,882 | 32,855,527 | 35,790,075 | 36,679,193 | 37,583,699 | 240,859,093 |
| 44 Niagara Mohawk Gas | (3,920,813) | 2,383,379 | 4,009,025 | 7,353,032 | 7,470,342 | 7,964,620 | 8,472,812 | 9,229,575 | 9,458,862 | 9,692,117 | 62,112,950 |
| 45 BUG | (10,226,575) | 6,216,519 | 10,456,656 | 19,178,761 | 19,484,737 | 20,773,953 | 22,099,459 | 24,073,310 | 24,671,353 | 25,279,747 | 162,007,919 |
| 46 LILCO - GAS | (6,071,976) | 3,691,026 | 6,208,585 | 11,387,290 | 11,568,962 | 12,334,427 | 13,121,440 | 14,293,403 | 14,648,488 | 15,009,719 | 96,191,365 |
| 47 LIPA | (14,297,962) | 8,691,429 | 14,619,642 | 26,814,177 | 27,241,969 | 29,044,445 | 30,897,659 | 33,657,336 | 34,493,472 | 35,344,078 | 226,506,246 |
| 48 Unregulated | (2,366,121) | 1,438,315 | 2,419,355 | 4,437,387 | 4,508,181 | 4,806,466 | 5,113,148 | 5,569,838 | 5,708,207 | 5,848,971 | 37,483,748 |
| 49 Narragansett | (3,008,882) | 1,829,036 | 3,076,577 | 5,642,811 | 5,732,836 | 6,112,152 | 6,502,145 | 7,082,895 | 7,258,852 | 7,437,855 | 47,666,277 |
| 50 Providence Gas | (2,231,660) | 1,356,579 | 2,281,869 | 4,185,221 | 4,251,991 | 4,533,326 | 4,822,580 | 5,253,317 | 5,383,823 | 5,516,588 | 35,353,634 |
| 51 Total | (75,190,200) | 45,706,533 | 76,881,851 | 141,010,538 | 143,260,211 | 152,739,081 | 162,484,773 | 176,997,378 | 181,394,452 | 185,867,623 | 1,191,152,240 |

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Economic Analysis of Customer Benefits
Illustrative Calculation of Synergy Value - Synergy

| | | Revenues (A) | Percent (B) | | Synergies (C) |
|---|---|---|---|---|---|
| 1 Massachusetts Electric | $ | 534,184,464 | 9.93% | $ | 15,487,662.95 |
| 2 Nantucket Electric | $ | 6,528,087 | 0.12% | $ | 189,269.47 |
| 3 New England Power | $ | 191,844,885 | 3.57% | $ | 5,562,177.71 |
| 4 Essex Gas | $ | 29,365,112 | 0.55% | $ | 851,385.59 |
| 5 Colonial Gas | $ | 98,219,521 | 1.83% | $ | 2,847,688.28 |
| 6 Boston Gas | $ | 352,057,800 | 6.54% | $ | 10,207,246.58 |
| 7 Granite State Electric | $ | 22,729,932 | 0.42% | $ | 659,011.16 |
| 8 EnergyNorth Gas | $ | 43,287,327 | 0.80% | $ | 1,255,033.75 |
| 9 Niagara Mohawk Electric | $ | 1,087,992,090 | 20.22% | $ | 31,544,262.18 |
| 10 Niagara Mohawk Gas | $ | 280,572,335 | 5.21% | $ | 8,134,661.43 |
| 11 BUG | $ | 731,811,000 | 13.60% | $ | 21,217,468.64 |
| 12 LILCO - GAS | $ | 434,509,000 | 8.08% | $ | 12,597,762.37 |
| 13 LIPA | $ | 1,023,158,400 | 19.02% | $ | 29,664,532.60 |
| 14 Unregulated | $ | 169,319,000 | 3.15% | $ | 4,909,082.50 |
| 15 Narragansett | $ | 215,314,821 | 4.00% | $ | 6,242,643.88 |
| 16 Providence Gas | $ | 159,697,000 | 2.97% | $ | 4,630,110.90 |
| 17 Total | $ | 5,380,590,774 | 100.00% | $ | 156,000,000.00 |
| 18 Synergy | | | | $ | 156,000,000.00 |

(A) Calendar 2005 Revenues
(B) Column A / Column A Line 17
(C) Line 18 * Column B

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Economic Analysis of Customer Benefits
Illustrative Calculation of Synergy Value - Cost to Achieve

| | | | Revenues (A) | Percent (B) | | Cost to Achieve (C) |
|---|---|---|---|---|---|---|
| 1 | Massachusetts Electric | $ | 534,184,464 | 9.93% | $ | 39,513,396.50 |
| 2 | Nantucket Electric | $ | 6,528,087 | 0.12% | $ | 482,879.81 |
| 3 | New England Power | $ | 191,844,885 | 3.57% | $ | 14,190,684.15 |
| 4 | Essex Gas | $ | 29,365,112 | 0.55% | $ | 2,172,124.78 |
| 5 | Colonial Gas | $ | 98,219,521 | 1.83% | $ | 7,265,255.99 |
| 6 | Boston Gas | $ | 352,057,800 | 6.54% | $ | 26,041,565.00 |
| 7 | Granite State Electric | $ | 22,729,932 | 0.42% | $ | 1,681,323.36 |
| 8 | EnergyNorth Gas | $ | 43,287,327 | 0.80% | $ | 3,201,945.08 |
| 9 | Niagara Mohawk Electric | $ | 1,087,992,090 | 20.22% | $ | 80,478,309.91 |
| 10 | Niagara Mohawk Gas | $ | 280,572,335 | 5.21% | $ | 20,753,815.71 |
| 11 | BUG | $ | 731,811,000 | 13.60% | $ | 54,131,746.91 |
| 12 | LILCO - GAS | $ | 434,509,000 | 8.08% | $ | 32,140,445.03 |
| 13 | LIPA | $ | 1,023,158,400 | 19.02% | $ | 75,682,589.57 |
| 14 | Unregulated | $ | 169,319,000 | 3.15% | $ | 12,524,454.07 |
| 15 | Narragansett | $ | 215,314,821 | 4.00% | $ | 15,926,745.29 |
| 16 | Providence Gas | $ | 159,697,000 | 2.97% | $ | 11,812,718.84 |
| 17 | Total | $ | 5,380,590,774 | 100.00% | $ | 398,000,000.00 |
| 18 | Cost to Achieve (Page 3 Line 18 times 2) | | | | $ | 398,000,000.00 |

(A) Page 3 Column A
(B) Column A / Column A Line 17
(C) Line 18 * Column B

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Economic Analysis of Customer Benefits
Illustrative Calculation of Synergy Value - Phase in Rates

| Cost to Achieve | | Synergy Multiplier | | Inflation | | Phase-In | |
|---|---|---|---|---|---|---|---|
| | (A) | | (B) | | (C) | | (D) |
| Year 1 | 38.49% | Year 1 | 50.00% | Year 1 | 1 | Year 1 | 50% |
| Year 2 | 15.30% | Year 2 | 68.33% | Year 2 | 1.0250 | Year 2 | 67% |
| Year 3 | 15.00% | Year 3 | 87.55% | Year 3 | 1.0506 | Year 3 | 83% |
| Year 4 | 6.78% | Year 4 | 107.69% | Year 4 | 1.0769 | Year 4 | 100% |
| Year 5 | 7.27% | Year 5 | 110.38% | Year 5 | 1.1038 | Year 5 | 100% |
| Year 6 | 5.97% | Year 6 | 113.14% | Year 6 | 1.1314 | Year 6 | 100% |
| Year 7 | 4.63% | Year 7 | 115.97% | Year 7 | 1.1597 | Year 7 | 100% |
| Year 8 | 2.12% | Year 8 | 118.87% | Year 8 | 1.1887 | Year 8 | 100% |
| Year 9 | 2.18% | Year 9 | 121.84% | Year 9 | 1.2184 | Year 9 | 100% |
| Year 10 | 2.25% | Year 10 | 124.89% | Year 10 | 1.2489 | Year 10 | 100% |

(A) Niagara Mohawk Rate Plan Attachment 10
(B) Column (C) * Column (D)
(C) Assumed Inflation Growth of 2.50%
(D) Niagara Mohawk Rate Plan Attachment 10

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Economic Analysis of Customer Benefits
Summary of EnergyNorth Efficiencies By Year

| | High Case (a) | Ratio (b) | Merger Case (c) | Year 1 (d) | Year 2 (e) | Year 3 (f) | Year 4 (g) | Year 5 (h) |
|---|---|---|---|---|---|---|---|---|
| 1 Electric T&D | - | 93.023% | - | 9% | 60% | 91% | 100% | 100% |
| 2 Gas Ops Total | 0.18 | 93.023% | 0.16 | 45% | 87% | 99% | 100% | 100% |
| 3 Customer Total | 0.15 | 93.023% | 0.14 | 19% | 50% | 72% | 85% | 100% |
| 4 Shared Services including SHES | 0.08 | 93.023% | 0.08 | 14% | 45% | 61% | 87% | 100% |
| 5 HR Services | 0.00 | 93.023% | 0.00 | 0% | 75% | 100% | 100% | 100% |
| 6 Total | 0.41 | 93.023% | 0.38 | | | | | |
| 7 Inflation | | | | 100.000% | 102.500% | 105.063% | 107.689% | 110.381% |
| 8 Electric T&D | | | | - | - | - | - | - |
| 9 Gas Ops Total | | | | 0.07 | 0.15 | 0.17 | 0.18 | 0.18 |
| 10 Customer Total | | | | 0.03 | 0.07 | 0.10 | 0.12 | 0.15 |
| 11 Shared Services including SHES | | | | 0.01 | 0.04 | 0.05 | 0.07 | 0.09 |
| 12 HR Services | | | | - | 0.00 | 0.00 | 0.00 | 0.00 |
| 13 Total | | | | 0.11 | 0.25 | 0.32 | 0.37 | 0.42 |

1 Page 7, Line 3, Column (a)
2 Page 7, Line 6, Column (a)
3 Page 7, Line 9, Column (a)
4 Page 7, Line 12, Column (a)
5 Page 7, Line 15, Column (a)
6 Sum of Lines 1 through 5
7 Inflation at 2.5 %

8 Line 1, Column (b) * Line 1 * Line 7, respective Column (d) through (h)
9 Line 2, Column (b) * Line 2 * Line 7, respective Column (d) through (h)
10 Line 3, Column (b) * Line 3 * Line 7, respective Column (d) through (h)
11 Line 4, Column (b) * Line 4 8 Line 7, respective Column (d) through (h)
12 Line 5, Column (b) * Line 5 * Line 7, respective Column (d) through (h)
13 Sum of Lines 8 through 12

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Economic Analysis of Customer Benefits
Summary of Niagara Mohawk Efficiencies By Year

| | Allocation of Savings—High End Estimate | Total (a) | NG (b) | NG/KS (c) | NG/LIPA (d) | KS (e) | KS/LIPA (f) | LIPA (g) |
|---|---|---|---|---|---|---|---|---|
| 1 | Electric T&D | 7.42 | 5.63 | - | 1.75 | - | - | 0.05 |
| 2 | Allocation to Energy North | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 3 | EnergyNorth Electric T&D | - | - | - | - | - | - | - |
| 4 | Gas Ops Total | 8.46 | 0.61 | 4.86 | - | 2.42 | 0.56 | - |
| 5 | Allocation to Energy North | | 0.00% | 2.03% | 0.00% | 2.56% | 2.56% | 0.00% |
| 6 | EnergyNorth Gas Ops Total | 0.18 | - | 0.10 | - | 0.06 | 0.01 | - |
| 7 | Customer Total | 14.43 | 4.88 | 2.28 | - | 1.18 | 6.09 | - |
| 8 | Allocation to Energy North | | 0.00% | 0.83% | 0.00% | 2.56% | 1.60% | 0.00% |
| 9 | EnergyNorth Customer Total | 0.15 | - | 0.02 | - | 0.03 | 0.10 | - |
| 10 | Shared Services including SHES | 5.17 | 0.14 | - | - | 0.36 | 4.67 | - |
| 11 | Allocation to Energy North | | 0.00% | 0.00% | 0.00% | 2.56% | 1.60% | 0.00% |
| 12 | EnergyNorth Shared Services including SHES | 0.08 | - | - | - | 0.01 | 0.07 | - |
| 13 | HR Services | 0.55 | 0.43 | 0.12 | - | - | - | - |
| 14 | Allocation to Energy North | | 0.00% | 0.83% | 0.00% | 0.00% | 0.00% | 0.00% |
| 15 | EnergyNorth HR Services | 0.00 | - | 0.00 | - | - | - | - |
| 16 | AMR in NY and LI | 11.80 | - | - | - | 7.32 | - | 4.49 |
| 17 | Allocation to Energy North | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 18 | EnergyNorth AMR in NY and LI | - | - | - | - | - | - | - |
| 19 | Total Efficiencies | 47.83 | | | | | | |
| 20 | Total Energy North | 0.12 | - | 0.12 | - | 0.10 | 0.19 | - |

1 Page 9
2 Not Applicable to EnergyNorth
3 Line 1 * Line 2
4 Page 9
5 (c) Page 8, Line 13 / Page 8, Line 20 & (e,f) Page 8, Line 13/ Page 8, Line 19
6 Line 4 * Line 5
7 Page 9
8 (c) Pg 8, Ln 13 / Pg 8, Ln 20, (e) Pg 8, Ln 13/ Pg 8, Ln 19, (f) Pg 8, Ln 21 / Pg 8, Ln 22
9 Line 7 * Line 8
10 Page 9
11 (e) Page 8, Line 13 / Page 8, Line 19 & (f) Page 8, Line 21/ Page 8, Line 2
12 Line 10 * Line 11
13 Page 9
14 (c) Page 8, Line 21 / Page 8, Line 23
15 Line 13 * Line 14
16 Page 9
17 Not Applicable to EnergyNorth
18 Line 16 * Line 17
19 Line 1 + Line 4 + Line 7 + Line 10 + Line 13 + Line 16
20 Line 3 + Line 6 + Line 9 + Line 12 + Line 15 + Line 18

## ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
### Economic Analysis of Customer Benefits
Summary of EnergyNorth Efficiencies By Year

| | | |
|---|---|---|
| | **Electric T&D Allocators** | |
| 1 | NiMo electric | 20.22% |
| 2 | MECo | 9.93% |
| 3 | Nantucket | 0.12% |
| 4 | NEP | 3.57% |
| 5 | GSE | 0.42% |
| 6 | Narr | 4.00% |
| 7 | Grid only | 38.26% |
| 8 | LIPA | 19.02% |
| 9 | Grid plus LIPA | 57.28% |
| | **Gas Allocators** | |
| 10 | NiMo gas | 5.21% |
| 11 | Prov | 2.97% |
| 12 | Grid only | 8.18% |
| 13 | Energy North | 0.80% |
| 14 | Boston Gas | 6.54% |
| 15 | Colonial Gas | 1.83% |
| 16 | Essex Gas | 0.55% |
| 17 | KEDNY | 13.60% |
| 18 | KEDLI | 8.08% |
| 19 | KeySpan Only | 31.40% |
| 20 | Grid plus KeySpan | 39.58% |
| | **Customer, Shared Svcs, Hr Svcs allocators** | |
| 21 | EnergyNorth | 0.80% |
| 22 | KeySpan opcos | 50.41% |
| 23 | Grid plus KS plus LIPA | 96.85% |

1-6 Page 3, Column (B)
7 Sum of Lines 1 though 6
8 Page 3, Column (B)
9 Line 7 + Line 8
10-11 Page 3, Column (B)
12 Line 11 + Line 12
13-18 Page 3, Column (B)
19 Sum of Lines 12 though 18
20 Line 12 + Line 19
21 Line 13
22 Line 8 + Line 19
23 Line 9 + Line 20

# ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
## Economic Analysis of Customer Benefits
Summary of EnergyNorth Efficiencies By Year

| | Total Efficiency Savings (from DPS-381 update to be filed) | Annual Savings in $ Millions (100% Phased-in) | | | | |
|---|---|---|---|---|---|---|
| | | Nominal | Low End | High End | Best Estimate | |
| | Initiatives listed in DPS-376 response | | | | | |
| 1 | Electric T&D | 8.95 | 5.30 | 7.42 | | |
| 2 | Gas Operations | 10.18 | 4.78 | 7.90 | | |
| 3 | Customers & Markets; Customer-Related Services | 12.15 | 4.50 | 8.41 | | |
| 4 | Shared Services including SHES | 5.25 | 3.93 | 5.17 | | |
| 5 | HR Services | 0.58 | 0.52 | 0.55 | | |
| 6 | AMR in NY and LI | 20.10 | 3.50 | 11.80 | | |
| | Initiatives related to DPS-383 response | | | | | |
| 7 | Gas Operations | 0.56 | 0.45 | 0.56 | | |
| 8 | Customers & Markets; Customer-Related Services | 3.69 | 0.91 | 2.40 | | |
| | Other initiatives related to National Grid "efficiencies" | | | | | |
| 9 | Customers & Markets; Customer-Related Services | 4.81 | 2.41 | 3.62 | | |
| 10 | Total "efficiency" savings | 66.27 | 26.30 | 47.83 | 44.49 | (1) |

(1) Based on an estimated $200 million in total savings
Efficiency portion equal to pro-rata of high-end estimate
(200/215) x $47.8 million = $44.5 million

# STATE OF NEW HAMPSHIRE
# BEFORE THE
# PUBLIC UTILITIES COMMISSION

**EnergyNorth Natural Gas, Inc. d/b/a National Grid NH**

**Docket DG 08-009**

**Direct Testimony**
**of**
**Nickolas Stavropoulos**

**February 25, 2008**

## I. Introduction

**Q. Please state your name and business address.**

A. My name is Nickolas Stavropoulos. My business address is 52 Second Avenue, Waltham, MA 02451

**Q. By whom are you employed and in what capacity?**

A. I am the Executive Vice President of Gas Distribution-US for National Grid USA, with responsibility for the company's regulated gas distribution operations in New Hampshire, Massachusetts, New York and Rhode Island. I am also the President and Chief Operating officer of EnergyNorth Natural Gas, Inc. d/b/a National Grid NH ("National Grid NH" or the "Company")

**Q. Please briefly describe your educational background and your business experience.**

A. I graduated from Bentley College in 1979 with a B.S. in Accounting and subsequently earned an M.B.A. from Babson College. In 1979, I joined Colonial Gas Company as an analyst in the rates and accounting areas. In 1982, I was promoted to Assistant Controller. In 1985, I became Vice President of Rates and Planning. In 1989, I was named Vice President and Chief Financial Officer. In 1995, I was elected Executive Vice President of Finance and Marketing as well as CFO, and I assumed responsibility for all of Colonial's financial, marketing, information technology and customer service functions. In 1999, following the acquisition of Colonial by Eastern Enterprises I was named Senior Vice President of Marketing and Gas Resources for Eastern's regulated gas distribution companies. When KeySpan Corporation acquired Eastern Enterprises in 2000, I was named KeySpan's Senior Vice President of Sales and Marketing for New England. I was subsequently named Executive Vice President of KeySpan Corporation and President of KeySpan Energy Delivery with responsibility for KeySpan's 2.6 million natural gas customers in New Hampshire, New York and Massachusetts. Following the National Grid plc acquisition of KeySpan Corporation I was named to my current position.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide an overview of the National Grid corporate structure and the benefits of this structure to its New Hampshire customers. I will also provide an overview of the Company's filing in this case and the more significant proposals contained therein. Finally, I will review the commitments agreed to by the Company contained in the merger settlement agreement approved by the Commission in Order No. 24,277, dated July 12, 2007, relating to the acquisition of KeySpan Corporation by National Grid plc.

## II. National Grid USA

**Q. Would you please discuss the National Grid corporate structure?**

A. National Grid USA is a wholly owned subsidiary of National Grid plc, a UK-based company whose stock is traded on the London Stock Exchange. American depository receipts (often referred to as ADR's) for National Grid plc are also traded on the New York Stock Exchange. Prior to its acquisition of KeySpan, National Grid USA operated five local distribution companies that served more than four million electric and natural gas customers in New York, Massachusetts, New Hampshire and Rhode Island. In August 2007, National Grid acquired KeySpan Corporation, which provides natural gas to 2.6 million customers in Massachusetts, New Hampshire and New York. In addition, KeySpan maintains the electric distribution system for the Long Island Power Authority, which provides electricity to 1.1 million customers on Long Island and supplies approximately 25% of New York City's electric capacity needs. Following the KeySpan acquisition, National Grid implemented an organizational structure based upon global lines of business that include (1) Transmission, (2) Gas Distribution, (3) Electric Distribution and Generation, (4) Business Development and Non-Regulated Operations and (5) Finance and Shared Services. Through this structure, we, at National Grid will be the foremost international electricity and gas company, delivering unparalleled efficiency, reliability and safety vital to the well-being of our customers and communities. We are committed to being an innovative leader in energy management and to safeguarding our global environment for future generations. This strategy is underpinned by our commitments to developing strong and valued relationships with our customers, regulators, suppliers, and the communities in which we operate and to acting responsibly in managing the environmental, economic and social risks associated with our actions. Long–term sustainability is an integral component of our overall business strategy. Additional information about National Grid's commitment to these important business objectives can be found in our 2007 Corporate Responsibility Report, a copy of which is provided as attachment NS-1 to my testimony.

**Q. How will New Hampshire customers benefit as a result of the National Grid acquisition of KeySpan Corporation?**

A. New Hampshire customers will benefit in a number of ways. First, as a result of the merger, the Company was able to avoid a rate increase up through and for a period of one year following the closing. Second, this filing includes permanent savings in the form of an annual credit of $619,000, representing National Grid NH customers' share of the net synergy savings that we expect to achieve as a result of the KeySpan Corporation acquisition. Importantly, these savings were derived by eliminating back office duplication of service and not by compromising safety, service or reliability. National Grid's strong commitment to safety, reliability and service quality is reflected in the Company's plans to invest $40 million in non-growth related projects in New Hampshire over the next two years, including its agreement to significantly enhance its bare steel and cast iron main replacement program, its commitment to enhanced emergency response times and its commitment to improve telephone call answering response times. Finally, by organizing along global lines of business, National Grid can take advantage of its size, scope and international expertise to identify and implement best practices in areas such as materials purchasing, infrastructure installation and maintenance processes, commodity procurement, remediation of environmental contamination at former manufactured gas plants sites, delivery of energy efficiency programs, and programs to assist low income customers all to the benefit of customers.

**Q. Please describe how you plan to address the particular needs and requirements of New Hampshire customers, given the size and scope of National's Grid's overall U.S. operations.**

A. As noted, our size and scope of operations will allow us to provide better, more efficient service to all of our customers. However, our business model recognizes that there are aspects of our business that remain local. To that end, we have appointed William Sherry as our Regional President, New Hampshire. In that role, Bill is responsible for government, regulatory, business and community relations for our combined gas and electric operations in New Hampshire. As the Commission is aware, Bill is a long time resident of New Hampshire and is very active in the community. Among his other activities, Bill serves on the boards of the Heritage United Way, the Salem Chamber of Commerce and Neighbor Helping Neighbor. He also serves on the Energy and Regulated Utilities Committee of the Business and Industry Association of New Hampshire and volunteers at the local state level for the American Cancer Society. Reporting directly to Bill is Deb Hale, another long time New Hampshire resident with many years of experience as an employee of the Company's regulated gas utility in New Hampshire. Together, Bill and Deb will ensure that the important issues and concerns of our New Hampshire customers, the Commission staff and the Office of Consumer Advocate receive the attention they deserve. Similarly, Bryan McCallum, Manager of Field Operations has been designated as our local gas distribution system contact for New Hampshire in the event that the Commission or the Commission staff, should ever have questions regarding the operation or safety of our system.

## III. Overview of Filing

**Q. Please provide an overview of the testimony being provided in this filing.**

A. In addition to my testimony, the case includes testimony from the following individuals:

**John O'Shaughnessy**—Mr. O'Shaughnessy is the Director of Service Company & Accounting Support for National Grid USA. His testimony sets forth the calculation of the revenue requirement and resulting revenue deficiency for the Company and provides the calculation of the Company's overall rate of return, and a comparison of the benefits to New Hampshire customers from the merger settlement to those received by New York customers. Mr. O'Shaughnessy has submitted separate testimony in support of the Company's proposal for temporary rates.

**Ann Leary**—Ms. Leary is the Company's Manager of Pricing–New England. Her testimony discusses the Company's test year revenue and gas cost adjustments, bill impacts of the rate changes being proposed by the Company and other proposed changes to the Company's tariff. Ms. Leary also jointly sponsors with Mr. O'Shaughnessy the testimony regarding the Company's request for temporary rates.

**Susan Fleck**--Ms. Fleck is the Vice President of Engineering Standards and Policy for National Grid USA. Her testimony reviews the Company's investment in system infrastructure and its commitment to safety, reliability and service quality.

**Gary Bennett**—Mr. Bennett is the Director Customer Meter Services, New England North. His testimony presents the Company's proposed collection procedures on a going-forward basis as required by the terms of a partial settlement agreement in the Company's recent indirect gas cost case (Docket DG 07-50).

**Gary Goble**—Mr. Goble is a management consultant with the firm of Management Applications, Consulting, Inc. ("MAC"). His testimony reviews the Company's proposed rate design, allocated and marginal cost of service studies and the cash working capital requirements.

**Paul Moul**—Mr. Moul is a management consultant for and principal of P. Moul and Associates. Mr. Moul's testimony sets forth the Company's cost of equity analysis.

**Paul Normand**—Mr. Normand is a consultant with Management Applications Consulting, Inc. His testimony presents the results of the Company's depreciation study.

**Q. What is the Company requesting in this proceeding?**

A. In this proceeding, the Company is seeking to increase its rates to address an annual revenue deficiency of $9,896,601. This proposal represents an average increase of approximately 5.6 percent on the total bill for the average customer. Although it is difficult at any time to raise rates for customers, it is noteworthy that the last increase in the Company's revenue requirement occurred in 1993. During those fifteen years, the Company has been able to maintain its rates through sales growth, merger synergies and cost reductions. At the same time, prices generally have increased nearly 50% as a result of inflation, and the Company has experienced declining average use per customer as a result of customer conservation and energy efficiency improvements to homes and natural gas heating equipment. Moreover, for the period 2001-2007 alone, the Company has invested in excess of $62 million in non-growth related capital projects that were designed to improve the reliability and safety of the National Grid NH distribution system. These factors and other increases in the costs of providing service to customers have caught up with the Company and resulted in the erosion of its rate of return, necessitating its request for a rate increase.

**Q. Did the Company earn its allowed rate of return in the test year ended June 30, 2007?**

A. No. Exhibit EN 2-2-1A, which is submitted as part of the Company's filing, shows that the Company earned a rate of return of 3.94% for the test year ended June 30, 2007, which is substantially less than the last allowed overall rate of return of 9.83% and is also below the proposed rate of return in the Company's filing in this case (9.26%). In fact, as the Commission is aware from the Company's quarterly Form F-1 filings, the Company has consistently earned substantially below its last allowed rate of return for a number of years.

**Q. How significant is the decline in average use per customer for National Grid NH?**

A. The Company has seen a dramatic reduction in gas usage per customer in recent years. Between December 2002 and December 2007, annual gas consumption by the typical National Grid NH residential heating customer decreased by nearly

13%. Commercial and industrial customers have exhibited similar patterns of conservation.

**Q. Can you comment on the factors that have contributed to this decline?**

A. The significant decline in use per customer over the five-year period 2003 through 2007 is most likely attributable to a significant run up in energy prices which caused permanent changes in customer behavior including a significant increase in the installation of energy efficiency measures. Significantly, heightened awareness of high energy prices appears to have caused customers to continue to conserve natural gas even though prices have moderated more recently.

**Q. A number of jurisdictions across the country have allowed distribution companies to implement revenue decoupling mechanisms as a means of addressing declining use per customer in order to continue to encourage investment in energy efficiency. Is the Company proposing to adopt such a mechanism in this case?**

A. National Grid is actively supporting decoupling mechanisms in the states in which we operate as a means of breaking the link between utility revenues and sales levels. Structured correctly, decoupling aligns the shareholder and customer interests to provide for more economically and environmentally efficient resource decisions. We seriously considered including such a proposal in this case. However, we ultimately concluded that including a revenue de-coupling proposal as part of this filing would be premature.

In May of 2007, the Commission issued an Order of Notice opening a generic investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to and encouraging investment in, energy efficiency. That proceeding is still very much in its early stages. Given the number of interested parties and myriad ways in which revenue decoupling mechanisms may be structured, we felt that the Commission should have an opportunity to reflect upon the views of all participants in the generic proceeding and announce its policy view on this important issue prior to deciding on a specific proposal for National Grid NH. We expect to be an active proponent of decoupling in the generic proceeding.

**Q. What is the status of revenue decoupling in the other National Grid jurisdictions?**

A. Massachusetts is also conducting a generic decoupling docket. In that proceeding, National Grid has recommended that the Department of Public Utilities ("DPU") implement a lost base revenue mechanism as an interim way to support the ramp up of energy efficiency and other demand response programs, and then move to fully decoupled rates on a permanent basis. The DPU has not yet issued an order in that docket.

In New York, on April 20, 2007, the Public Service Commission issued an order in a generic decoupling proceeding requiring that each utility in the state include a revenue decoupling mechanism as part of its next rate plan. National Grid's two regulated gas distribution subsidiaries, KeySpan Energy Delivery Long Island and KeySpan Energy Delivery New York, had rate cases pending before the New York Commission at the time the order was issued. Therefore, a collaborative was established and began discussions in December 2007 for the purpose of designing a revenue decoupling mechanism for the two companies. A joint proposal from the collaborative is expected in March 2008.

**Q. Does the Company's proposed rate design address the issue of declining use per customer?**

A. Partially. In this filing, the Company is proposing to set the customer charge for each rate class closer to the marginal cost to serve the class and to reduce the variable charges associated with the tail block and head block charges. Such a design will allow the Company to recover more of its fixed costs to serve through a demand base rate and reduce its revenue stream reliance on the variable charges associated with customer use. However, due to customer bill impact concerns, we have not set the customer charge at the full marginal cost to serve each class. Therefore, this rate design does not fully de-link customer consumption from the delivery revenue stream.

**Q. Isn't such a rate design likely to send inappropriate price signals to customers and discourage conservation?**

A. No. The rate design proposed by the Company properly reflects the fact that the base rates, or delivery rates, charged by the Company primarily recover fixed costs that the Company incurs regardless of the level of consumption. Commodity charges, which vary with use, make up nearly 70% of the total bill received by the customer. Therefore, conservation will still result in significant savings to the customer.

**Q. How will the Company proposal affect its energy efficiency program?**

A. Over the past several years, there has been an unprecedented demand for energy and, in turn, energy efficiency. Energy-efficient equipment runs longer, better, more cost-effectively and with less fuel. Energy efficiency can help tackle issues ranging from high energy prices to climate change and fuel supply concerns. National Grid is active in the development of national, state and regional energy legislation and regulatory requirements geared towards energy efficiency. National Grid has been running electric energy efficiency programs for customers in New England for 20 years. National Grid and its allies have shaped programs to take advantage of new technologies, responded to the changing needs of customers and addressed the requirements of ever changing policy. As a result of its acquisition of KeySpan, National Grid now also offers its customers a broad portfolio of nationally recognized gas efficiency programs. KeySpan has long been a recognized leader in providing world-class energy efficiency programs and services, and National Grid looks forward to continuing that tradition. We are committed to educating homeowners and building operators about energy efficient practices and working closely with manufacturers to transform markets for increasingly efficient equipment. Our programs have received numerous awards from the U.S. Environmental Protection Agency, the Department of Energy and the American Council for an Energy Efficient Economy. In New Hampshire, we are presently in the second year of our most recently approved three year energy efficiency program. The program design is reviewed each year by the Company, the Commission staff, the Office of Consumer Advocate and other interested parties to determine that budget levels are appropriate, that the appropriate measures are being offered to customers and that they are being delivered as cost-effectively as possible. The Company remains committed to providing cost-effective energy efficiency programs and looks forward to the opportunity to discuss through the collaborative process set in place by the Commission the terms under which its programs can be continued and expanded in the future.

**Q. Would you please discuss the Company's proposal for treatment of pensions and post-retirement benefits other than pensions ("OPEB")?**

A. In this proceeding, the Company is proposing to establish a pension/OPEB reconciliation adjustment mechanism. Generally speaking, reconciling mechanisms are appropriate to allow recovery of certain rapidly changing costs by permitting the rate to adjust periodically to reflect actual expenses. One example of this is the cost of gas. Similar to the commodity cost of gas, the calculation of pension and OPEB contribution and expense under the rules of the Financial Accounting Standards Board produces a highly volatile result from year to year which is essentially outside the control of the Company. The Company's proposed reconciliation mechanism will allow the Company to recover its pension costs incurred in providing service to customers, and benefit customers by ensuring that an inappropriately high level of pension and OPEB expense is not locked into base rates. Under the Company's proposal, customers pay no more or less than that the Company is required to accrue in order to meets its obligation to employees. Details of the proposal and the reconciliation mechanism are contained in the testimony of Mr. O'Shaughnessy.

**Q. In a recent gas cost proceedings, the Commission staff expressed concerns regarding the Company's collections practices, its level of uncollectible accounts and it bad debt percentage. Has the Company addressed this issue in the filing?**

A. The bad debt percentage reflected in this filing is 2.54%, based on a three year historical average. While the Company recognizes that this is a higher level than many other gas companies in the Northeast, it appropriately reflects the Company's experience for purposes of setting rates. The Company is aware that the Commission staff believes that the Company can improve its performance with regard to uncollectible accounts, and has developed a proposal to increase its staffing in that area and to make a number of changes to its collections process. Specifically, as agreed to in a partial settlement with Commission staff and the Office of Consumer Advocate in Docket DG 07-50, the Company undertook an extensive review of its collection processes and prepared a plan that includes adding additional field collectors and modifying certain aspects of the existing collections process. The Company has also committed to work with the Commission staff, the Office of Consumer Advocate and an independent consultant to determine an appropriate bad debt percentage that reflects the Company's particular circumstances and the changes that the Company plans to make to its collections process.

**IV. Compliance with the EnergyNorth Rate Agreement**

**Q. The EnergyNorth Merger Rate Agreement set forth a number of requirements that relate to this rate case. Can you summarize the status of those items?**

A. Yes. The items set forth in Section 1 of the agreement have been addressed as follows.

Section 1B required the Company to submit an updated depreciation study with this filing. An updated depreciation study is included in this case with the testimony of Mr. Normand.

Section 1C required the Company to reflect a net synergy savings credit equal to $619,000 annually in its cost of service. That credit is included in the cost of service, as discussed in the testimony of Mr. O'Shaughnessy.

Section 1D provided that the Company use a capital structure composed of fifty percent equity and fifty percent debt in this case. As discussed in the testimony of Mr. O'Shaughnessy, the Company's filing does that.

Section 1E authorized the Company, in accordance with applicable accounting rules, to perform a market valuation of the assets in its pension and OPEB plans as of the closing date of the merger and defer recognition of any unrecognized gains or losses resulting from such valuation, with the deferred amount to be amortized over a period equal to the average estimated remaining service lives of the employees in the plan. The determination of the required deferral is pending as of the date of this filing, but is expected to be final by the Company's fiscal year end, March 31, 2008. Once the amount is known, the Company will establish the deferred account and amortize the balance as contemplated by the merger agreement.

Section 1F provided that the Company was not permitted to recover the acquisition premium from the KeySpan/National Grid merger or any prior mergers. Consistent with that provision, the rate base reflected in this filing has been stripped of any acquisition premium (sometimes referred to as goodwill), as required by the agreement.

Q. **Section 3 of the Merger Rate Agreement provides that the Company may amortize the prudently incurred costs to achieve ("CTA") the merger over ten years in this filing. Has the Company done so?**

A. Yes. As provided for in the settlement, the Company has included an estimated CTA of $409,203 in this filing. Under the terms of the settlement, each May 1 the Company will report the actual CTA incurred for the prior calendar year and the annual CTA will be appropriately adjusted.

Q. **Section 4 of the Merger Rate Agreement provides that the Company will submit an analysis of the economic benefits related to the allocation, calculation and sharing of synergy savings from the merger that is being provided to National Grid's New York customers. Has that analysis been prepared?**

A. Yes, the analysis was prepared by Mr. James Molloy and included as Attachment JOS-2 to the cost of service testimony of Mr. O'Shaugnessy.

**Q. Section 5 of the Merger Rate Agreement provides that the Company will implement an enhanced cast/iron bare steel program beginning with fiscal year 2009. Has the Company implemented such a plan?**

A. On February 13, 2008, the Company submitted a proposal for fiscal year 2009 to Commission staff for review. The proposal calls for the Company to replace approximately 4.76 miles of main at an estimated cost of $3.1 million. Further details are discussed in the testimony of Ms. Fleck.

**Q. Section 6 of the Merger Rate Agreement provides that the Company will bring its performance regarding call answering time to answering 80% of calls within 30 seconds by the end of the first full calendar year following the merger. Has the Company taken steps to achieve that goal?**

A. Yes. Further details are provided in the testimony of Ms. Fleck.

**Q. Section 6 also imposes certain performance reporting requirements on the Company. Has the Company met those requirements?**

A. The Company has met those requirements to date and is committed to meeting its requirements going forward.

**Q. Section 7 of the Merger Rate Agreement lists a number of operating commitments. Has the Company complied with these requirements?**

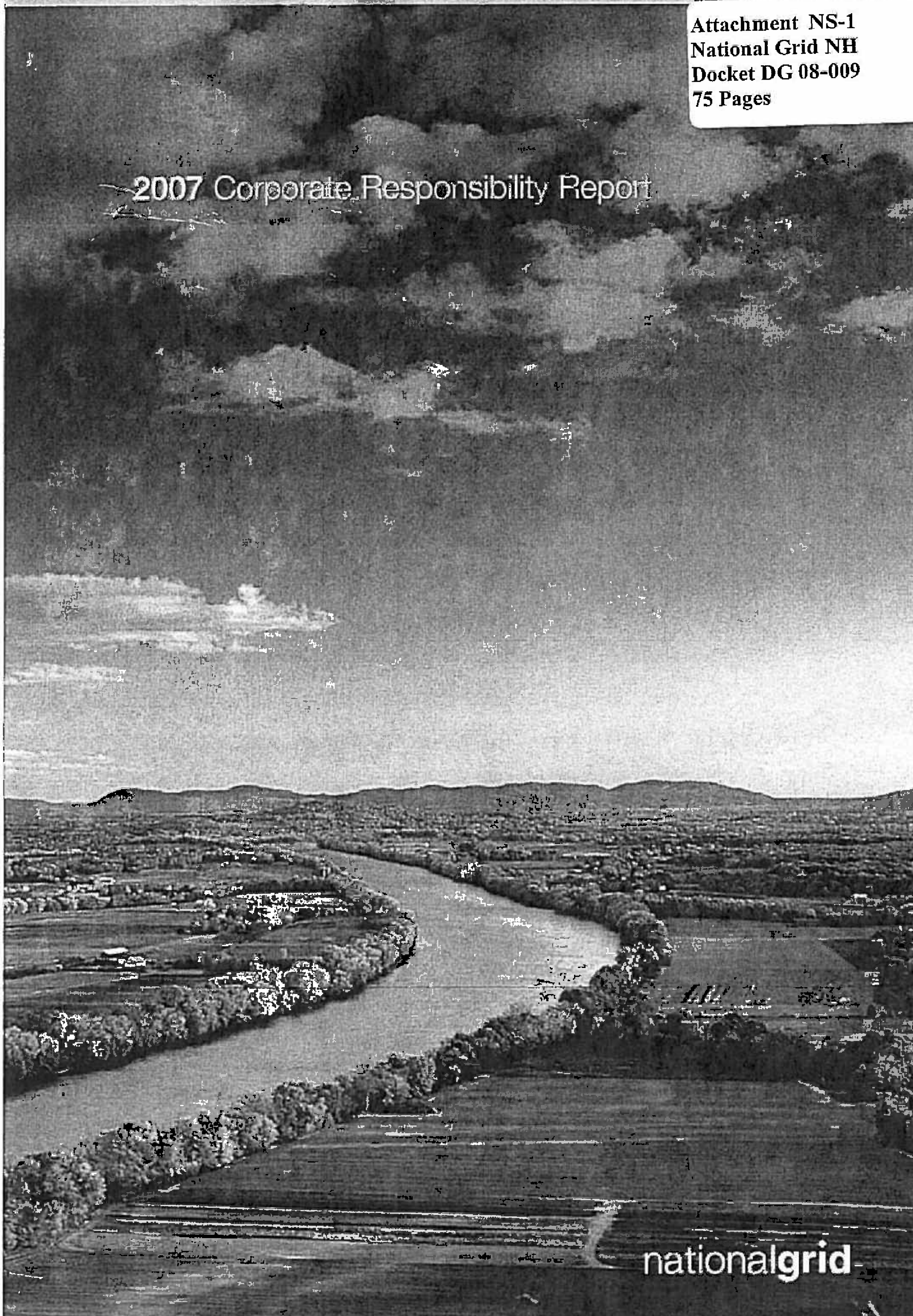
A. To the extent that this section references maintaining certain current operating practices and operating locations, the Company has and will continue to comply. The annual operating report is not yet due but the Company expects to submit it by May 1 as required by the settlement agreement. With respect to emergency response times, the Company has taken steps to satisfy these requirements and fully expects to achieve full compliance by the end of calendar year 2008. Further details of the steps taken by the Company are contained in the testimony of Ms. Fleck.

**Q. Does this conclude your testimony?**

A Yes it does.

Attachment NS-1
National Grid NH
Docket DG 08-009
75 Pages

# 2007 Corporate Responsibility Report



# Table of Contents



Unless otherwise noted, all references to National Grid in this report are about the company's US operations.

## Introduction

## ◆ To Our Stakeholders

*Steve Holliday, Chief Executive*

National Grid is an international electricity and gas company and one of the largest investor-owned utilities in the world. It is the largest utility in the UK and, as a result of the recent merger with KeySpan, the second largest utility in the US. In the Northeast US, National Grid now distributes electricity to approximately 3.3 million customers, services the 1.1 million electric customers of the Long Island Power Authority, owns and operates generation stations with a total capacity of 6600 MW, owns gas storage facilities and provides natural gas to approximately 3.4 million customers. Our employees in the US now total 17,943.

We were pleased when in 2006 the CERES Board of Directors approved National Grid into its network of companies. We were, in fact, one of the first Northeast utilities to join this distinguished coalition of investors, environmental groups and other public interest organizations who work closely with companies to address pressing sustainability issues such as climate change.

This first Corporate Responsibility Report as a member of CERES ties directly to National Grid's strategic ambition which is centered on our commitment to reshape the way our energy services impact people's lives. We intend to:

- transform our infrastructure, technology and innovation to supply and deliver reliable, clean energy.
- create energy products and services that meet our customers lifestyles,
- help customers make responsible energy-related choices,
- achieve breakthroughs in energy efficiency, conservation and reduced demand,
- ensure secure and affordable energy supply, production and delivery,
- raise the bar on environmental stewardship, and
- enrich the communities where our customers and employees live and work.

Underpinning these commitments is our Framework for Responsible Business. This set of principles provides a foundation and context for corporate governance and assists in our decision making around economic, environmental and social issues as they relate to you, our stakeholders. Broadly speaking, our Framework covers our three main business goals:

**Sustainable Growth** – This includes acting with honesty and integrity and in accordance with laws and regulations, proactively managing environmental risks and contributing to the economic growth of our service territories.

**Profits with Responsibility** – We seek to improve efficiency without sacrificing reliability or integrity, maintain strong internal controls, make efficient use of natural resources, keep waste to a minimum and contribute to minimizing global climate change.

**Investing in the Future** – We will provide high-quality, dependable services, seek increasing returns for our shareholders, participate in the development of laws and initiatives that improve the environment and overall quality of life and encourage and support investment in the community.

This report will demonstrate our transparency in discussing our performance regarding these goals in Fiscal Year 2007. Data for the report have been compiled and presented based on the Global Reporting Initiative (GRI) Sustainability Reporting Guidelines (G3) as well as the Electric Utility Supplement and is as comprehensive as we can make it.

In Fiscal 2007, we made progress in all our sustainability efforts. That included environmental and social awards for energy efficiency, vegetation management, wildlife conservation, employee volunteerism and corporate citizenship.

Although we are gratified with these awards, we remain acutely aware of the challenges we face over the next three to five years. Operationally, the most significant of these is making the integration with KeySpan successful. Once this is completed, National Grid will be a much larger and, in many respects, more complex company with more customers and environmental and social issues to address. We have made strides to smooth the integration process. KeySpan also has the reputation as a leader in sustainability, and we have every intention of maintaining their strong policies and procedures moving forward.

It is my hope that this first National Grid US Corporate Responsibility Report will stimulate your thinking and underscore our commitment to act in a responsible manner.

Sincerely,

Steve Holliday
CEO

## ◆ About This Report

The corporate vision of National Grid is to grow our businesses to create value for our shareholders and customers through safe, reliable, efficient, and responsible delivery of electricity and natural gas. This strategy is underpinned by our commitments to developing strong and valued relationships with our customers, regulators, suppliers and the communities in which we operate and to acting responsibly in managing the environmental, economic and social risks associated with our actions. Long-term sustainability is an integral component of our overall business strategy.

**The Reason for This Report**

This first US Corporate Responsibility Report has been put together in an effort to discuss how the Company managed its environmental, economic and social impacts in Fiscal Year 2007 and what its strategy is moving forward.

**Performance at a Glance**

National Grid delivered strong performance on all fronts in Fiscal Year 2007 (FY07).

Revenue reached $15.4 billion and operating profit was $4.5 billion. The Company generated more than $5.3 billion in cash from operations. Adjusted profit before tax and adjusted earnings per share rose 3 percent and 5 percent, respectively. And, the Company has produced a three-year return on equity of 12.4 percent. Clearly, National Grid delivered value for shareholders.

To sustain that momentum, National Grid has focused on several growth initiatives. The most significant of these was the acquisition of KeySpan in August of 2007. KeySpan is a major US-based gas and electricity energy business with 2.6 million gas customers in New York, Massachusetts and New Hampshire and 1.1 million electricity customers in New York served on behalf of the Long Island Power Authority. As a result of this aquisition, National Grid is a substantially larger company with a major position in electricity and gas transmission and distribution. Moreover, the integration of KeySpan into the National Grid business will provide a model for future acquisitions. In Fiscal Year 2007, the Company completed the acquisition of the Rhode Island gas distribution network from Southern Union Company. The Rhode Island gas business serves 245,000 customers.

Beyond acquisitions, National Grid has focused on improving productivity and customer service, at the same time reducing costs while continuing to make capital investments to enhance the reliability of its operations. In Fiscal Year 2007, the Company embarked on a comprehensive reliability enhancement program in the United States, with $150 million of work completed.




Environmentally, National Grid is committed to mitigating the effects of global climate change and reducing its carbon footprint. The Company is focused on carrying out its business operations in a sustainable and responsible manner. Toward that end, National Grid UK has committed all of its international operations to a 60 percent reduction in greenhouse gas emissions from its processes, operations and offices by 2050. As part of our climate change initiative, we plan to move to 100 percent renewable energy for internal use by 2010. The Company is also reviewing all of its business practices, policies and procedures to consider the impact of climate change on its operations with an eye toward reducing that effect.

Throughout this report are examples of actions National Grid is taking to improve its environmental and reliability performance, whether in lowering greenhouse gas emissions, protecting plants and animals, remediating brownfield or impaired legacy sites or replacing and repairing assets and undertaking many other actions.

Safety impacts everything National Grid does and remains a major focus companywide for our employees, our suppliers and the public we serve. Our goal is zero injuries every day. In Fiscal Year 2007, the Company saw a decline in safety performance, with 91 employees suffering lost-time injuries. National Grid considers that unacceptable and is committed to creating a culture that delivers safer ways of working.

Our commitment to safety is one aspect of National Grid's dedication to serving our own people and the greater society. The Company has also made training and development of employees and inclusion and diversity top priorities. In addition, we strongly support community involvement, with employees in the US devoting tens of thousands of hours in service to their communities. And we are supportive of human rights both in our operations and in those of our suppliers.

This report covers National Grid's efforts to be a financially successful and responsible company creating value and doing right by those we serve.

**Strategy and Analysis**

Energy and climate change represent enormous challenges and opportunities for National Grid and society. As such, the Company is taking action across its operations to make sure that the business is sustainable and responsible.

Toward that end, National Grid has implemented a company-wide sustainability strategy aimed at producing a low-carbon business model that reduces greenhouse gases, promotes renewable energy, and supports regional and federal legislation to cut greenhouse gas emissions in all sectors of the economy.

*Reliability enhancements include line replacement as well as substation reconstruction.*

National Grid has made sustainability in the United States a key element of our corporate culture, with employees trained to think and act in an environmentally responsible manner. Moreover, the Company provides strong leadership, management and training as part of its environmental programs. In the United States, for example, our Environmental Department consists of full-time professionals, including scientists and engineers who investigate contaminated sites and manage remediation, and others who assist in monitoring environmental requirements associated with line construction, maintenance and operations.

**Materiality**

This first Corporate Responsibility Report for National Grid US contains information about the Company's economic, environmental and social policies and performance. It is a comprehensive report that identifies the six key areas of focus that we believe to be the most important as part of National Grid's sustainability program.

The six material issues we have identified are as follows:

- **Safety**
  Safety is at the heart of all of our activities and continues to be at the top of the Board of Directors' agenda. In Fiscal Year 2007 we saw a decline in our performance and, as a result, we need to reinforce a culture which continually delivers safer ways to protect our employees, contractors and the public.
- **Reliability**
  The reliability of our energy networks and the delivery of energy to our customers is our highest priority after safety. Our approach to maintaining and improving reli-

ability involves investments in infrastructure, investments in our people, and maintaining a constant focus on reliability as one of our principal objectives.

- **Climate Change**
  Climate change is possibly one of the greatest challenges facing our society in the 21st century. As we move to a low-carbon economy, there will be a significant change in electric and gas markets and, in particular, infrastructure requirements. We have a role in helping society deliver improvements to reduce climate change impacts.
- **Work Force Efficiency**
  Our objective is to deliver services as efficiently as possible. This allows us to maintain reasonable prices for our customers and improve our financial performance to the benefit of our shareholders. One way we are striving to be more efficient is by integrating National Grid's international operations around lines of business and removing geographic boundaries.
- **Financial Performance**
  If we achieve our objectives, we expect to deliver continued improvements in financial performance.
- **Growth and Investment**
  We invest in our existing businesses; and where we believe we can create value through operational improvements, synergies and financial benefits, our parent company considers investing in infrastructure businesses in the US energy market. Examples are the acquisition of the Rhode Island Gas distribution network, as well as the merger with KeySpan.

We believe the six material issues can be rolled up into three major themes which we carry forward throughout the report, namely: safety, reliability and climate change.

While the above are the material issues for National Grid currently, the Company recognizes that with the completion of the KeySpan merger these issues will become even more significant. For example, as a result of the KeySpan merger, National Grid now owns electric generating assets on Long Island and in New York City. These generating stations will create an added focus for purposes of our climate change strategy.

**Report Parameters**
This report is based on performance and information for Fiscal Year 2007 (April 1, 2006-March 31, 2007) and relates to National Grid's US operations only. Where appropriate, data from other years are used for trending or comparative data. National Grid's 2006/07 Annual Report provides additional data for our US operations and can be found at www.nationalgrid.com.

For this report, information relating to Rhode Island Gas and KeySpan has not been included. The acquisitions of Rhode Island Gas and KeySpan were not completed until August 2006 and August 2007, respectively. Future reports will include KeySpan and Rhode Island Gas.

**Stakeholder Review**
National Grid US worked with the Coalition for Environmentally Responsible Economies (CERES) – a national network of investors, environmental organizations and other public interest groups that consult with companies on sustainability issues – to review our report and provide comments. We have participated in several calls with representatives from a number of environmental, social and investor organizations to obtain feedback on our report.

We believe the stakeholders for this report are:

- Existing and prospective investors
- Customers
- Employees and retirees
- Labor unions
- Local communities
- Federal, state and local policymakers
- Suppliers

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- Non-governmental organizations
- Industry professionals
- Governmental representatives
- Academia

**Distribution of Report**

The audience for our report consists of both internal and external stakeholders, as identified above. A paper version will be available and will be distributed upon request. In addition, the report will be located on our website at: www.nationalgrid.com.

**Sustainability Reporting Guidelines**

This printed version of our first US Corporate Responsibility Report, along with additional information available on the National Grid US website, is compiled and presented based on the Global Reporting Initiative (GRI) Sustainability Reporting Guidelines (G3) as well as the Electric Utility Supplement.

The GRI guidelines provide a voluntary reporting framework used by organizations around the world as the basis for sustainability reporting. The GRI is the generally accepted format and framework for "measuring, disclosing, and being held accountable to internal and external stakeholders for organizational performance toward the goal of sustainable development."

**Reporting Cycle**

As noted earlier, this is our first US Corporate Responsibility Report. We have published environmental reports on an annual basis since 2002; the last one was based on our Fiscal Year 2006. Our plan is to issue a Corporate Responsibility Report every other fiscal year (every two years).

**Completeness, Reliability and Accuracy**

National Grid does not yet have a formal information collection system for the GRI process. Each line of business has collected data for which it is responsible. Much of this information is also provided to our parent company for use as part of the Corporate level sustainability reporting. This can be viewed at www.nationalgrid.com.

**Assurance**

ESS Group Inc. has been used to independently verify the contents of the report. ESS Group is a multidisciplinary environmental engineering and consulting firm located in East Providence, Rhode Island and Wellesley, Massachusetts. Their independent verification can be seen at the end of this report.

**GRI Context Index and Key Performance Indicators**

At the end of the report is an index identifying where in the report we satisfy the GRI reporting guidelines as well as a chart listing key performance indicators.

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## ◆ Overview of Our Company

National Grid US is a wholly owned subsidiary of National Grid plc, a UK-based company whose stock is traded on the London Stock Exchange. Prior to its acquisition of KeySpan, National Grid US operated five local distribution companies that served more than four million electric and natural gas customers covering an area of 29,000 square miles in New York, Massachusetts, Rhode Island and New Hampshire. During FY2007, the headquarters for the US operations were located in Westborough, Massachusetts. Following is a breakdown by area:

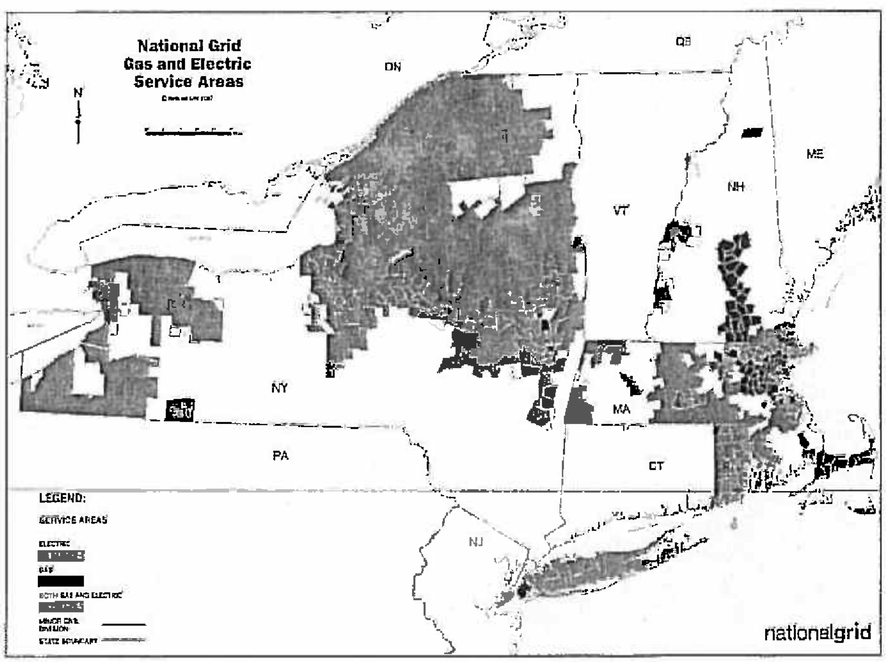
***New York*** – National Grid serves 1.6 million electric customers in 669 communities and delivers natural gas to 569,000 customers in 216 communities.

***Massachusetts*** – National Grid serves 1.2 million electric customers in 168 communities. On the Island of Nantucket, the Company serves 12,000 electric customers.

***Rhode Island*** – National Grid serves 478,000 electric customers in 38 communities and delivers natural gas to 245,000 customers in 33 communities.

***New Hampshire*** – National Grid serves 41,000 electric customers in 21 communities.

**Current National Grid Service Territory in the United States / Fiscal Year 2008**
In addition, in August 2007, during its Fiscal Year 2008, National Grid acquired KeySpan Corporation of Brooklyn, New York, which provides natural gas to 2.6 million customers in Massachusetts, New Hampshire and New York, and maintains the electric distribution system for the Long Island Power Authority (LIPA), which provides electricity to 1.1 million customers on Long Island. Keyspan also supplies approximately 25% of New York City's electricity capacity needs and operates LIPA's transmission and distribution system under contract to LIPA. Set forth on the next page are some of the highlights and benefits of National Grid's merger with KeySpan.




*Combined gas and electric service territories post KeySpan acquisition.*

**Benefits of the Merger**

[illegible]

Even prior to the acquisition of KeySpan, National Grid was a very large company – 8th largest US utility and 19th largest UK organization overall. Below is a table of recent financial highlights for the past 4 years.

**National Grid plc/Financial Highlights**

| Fiscal year | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Total assets (£m) | [illegible] | [illegible] | [illegible] | [illegible] |
| Total borrowings (£m) | [illegible] | [illegible] | [illegible] | [illegible] |

Note: [illegible]

### Service Area Population

The numbers are from the 2000 U.S. Census (partial census tracts are adjusted by difference in area)

- Upstate NY – 3,787,156
- New England – 3,964,483

### Sources/Fuel Mix of Distributed Electricity

Fuel source mix varies by the type of service and customer location but includes varying percentages of the following power sources:

- Biomass
- Coal
- Diesel
- Digester Gas
- Efficient Resource
- Fuel Cell
- Hydroelectric/Hydropower
- Jet
- Landfill Gas
- Municipal Solid Waste
- Natural Gas
- Nuclear
- Oil
- Solar Photovoltaic
- System Mix
- Trash to Energy
- Wind
- Wood

### Shareholders

- Number of Common Shareholders – 1,219,611
- Number of Common Shares Outstanding – 2,701,058,872

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**Electric and Gas Transmission and Distribution**
National Grid US maintains 8,500 miles of transmission overhead lines and 89 miles of underground cable and operates 501 electricity substations. It provides 71,000 circuit miles of electricity through its distribution network, which covers 29,000 square miles of service territory. The company has 11,800 miles of natural gas pipeline over its 5,460 square-mile gas service territory.

**Business Priorities**
National Grid is focusing its core skills on operating in the electricity and natural gas sectors in the United States in a safe, reliable, efficient and responsible manner. The Company is committed to ensuring a disciplined approach to operating its business, reducing inefficiencies and developing more effective ways to work.

*Gas and electric employees are committed to working safely, reliably, efficiently and responsibly.*

## ◆ Corporate Governance

The Board of National Grid is committed to instilling best corporate governance practices throughout its operations. The Board of Directors leads the governance effort through National Grid's Framework for Responsible Business. The Framework defines the principles by which the Company manages its businesses, sets the context for corporate governance, and assists leadership in taking into account economic, environmental and social factors in our decision-making.

Our Framework is based on three overriding business goals, each with multiple underlying values:

***Sustainable growth***

- Contribute to the economic growth in our service territories
- Act with honesty and integrity
- Proactively manage environmental risks
- Promote inclusion and diversity in employee ranks
- Employ the right number of people with the right skills
- Treat employees fairly
- Act in accordance with all laws and regulations
- Respect human rights

***Profits with responsibility***

- Seek efficiency improvements without compromising reliability and integrity
- Maintain strong internal financial controls
- Efficient use of natural resources
- Keep waste to a minimum and recycle when possible
- Contribute to minimizing global climate change
- Safeguard our employees, contractors, and the public we serve
- Conduct business in a professional manner
- Maintain an open and constructive dialogue with our stakeholders

*Investing in the future*

- Seek increasing returns for our shareholders
- Provide high-quality dependable services
- Improve, where practicable, the environmental status of the land on which we operate
- Participate in development of laws and initiatives to improve the environment and overall quality of life
- Contribute to continued development of our employees
- Recognize and reward employees for their contributions
- Encourage and support investment in the community with an emphasis on developing partnerships

All National Grid US businesses must operate within the guidelines and context of the Framework.

There are a number of underlying corporate governance policies, procedures and processes that support and reinforce the tenets of the Framework:

- *Standards of Ethical Business Conduct* - Applies to all National Grid US employees – all US employees receive periodic training on the standards of conduct.
- *Risk Management procedure* – The National Grid risk management procedure requires the conduct of a risk assessment and reporting minimally twice a year on significant risks the Company faces. The Company will be moving to quarterly reporting.
- *Compliance Management procedure* – The National Grid compliance management procedure requires the conduct of a compliance risk assessment and reporting minimally once a year on significant compliance risks the Company faces. The Company will be moving to quarterly reporting.
- *Delegations of Authority* – The Corporate Delegations of Authority policy establishes a cascading hierarchical matrix listing of those employees, management and executives who have the authority to commit Company resources.
- *Letters of Assurance (LOA)* – The Corporate LOA procedure establishes an annual process of upward cascading of formal attestations by senior management ultimately to the Board of Directors on issues of risk and compliance management, internal controls, corporate responsibility and overall governance.

As such, the Company has put in place policies, public position statements, and internal control procedures to ensure the most important issues that arise relating to corporate governance and ethical conduct are managed appropriately. Key policies cover areas such as safety and occupational health, anti-fraud and bribery, conflicts of interest, protection and disclosure of inside information, environment, human resources, information and records management, and community investment. Annually, all management employees are required to sign a certification indicating that they have read and understood the Standards of Ethical Business Conduct, have been abiding by them and will continue to do so and attest that the information on the verification form is correct and accurate.

The US Compliance & Ethics Committee meets tri-annually to review the results of various aspects of National Grid's corporate governance system. At each meeting the following areas of activity are reviewed:

- Internal audits
- Environmental and Safety audits
- Ethical Business Conduct Advice Team
- Results of investigations into misconduct
- Standards of Conduct training
- Risk management activities
- Compliance management activities

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Activities reported to the committee are also ultimately reported to the National Grid Risk & Responsibility Committee and the Audit Committee.

National Grid also has a number of area specific committees which monitor day to day activities. Such committees include:

- Environmental Oversight Committee
- Climate Change Task Force

Details regarding some of the committees are discussed later in the report.

During Fiscal Year 2007, an assessment of risk and compliance management was conducted twice for all National Grid US businesses. There were no instances discovered of significant corruption, anti-competitive behavior, anti-trust or monopoly behavior, and no instances of significant monetary fines or non-monetary sanctions for non-compliance with laws or regulations. All allegations of misconduct of any kind on the part of Company employees were investigated thoroughly and on a timely basis through resolution, with appropriate disciplinary actions administered, up to and including termination of employment.

## ◆ Benchmarking Our Performance

National Grid plc takes part in a number of ratings and benchmarks of our economic, environmental and social performance. These assessments are conducted by independent organizations. We believe we can better understand our environmental, social and economic impacts and make the changes required to improve our performance if we receive input from these outside organizations.

We are rated or benchmarked by the following organizations or indices:

- Dow Jones Sustainability Indices
- FTSE4Good
- FTSE ISS Corporate Governance Index
- oekom research AG
- Business in the Community (BITC)
- Ethibel
- Vigeo
- Carbon Disclosure Project
- Global Climate 100 Index

**Pacific Sustainability Index**
In 2006, National Grid was the highest scoring utility company in environmental and sustainability reporting among the world's largest utilities for the second year in a row, according to the Roberts Environmental Center at Claremont McKenna College in Claremont, Calif. The Center's Pacific Sustainability Index (PSI) gave National Grid (both its US and European operations) an A+ rating. The Pacific Sustainability Index considers such factors as environmental intent, environmental reporting, environmental performance, social intent, social reporting and social performance.

**Corporate Responsibility Index**
National Grid was named a top performer in the 2007 Corporate Responsibility Index run by Business in the Community in the UK.

The Company is one of 29 platinum companies and a Top 10 global leader in the Index. In the previous three years, National Grid has been first, second and fourth and has each year topped the multi-utilities sector.

The Index provides a benchmark for companies to evaluate their management practices in four key areas of corporate responsibility – community, environment, marketplace and workplace.

Copies of reports on National Grid by these organizations are available by going to: http://www.nationalgrid.com/corporate/Our+Responsibility/Benchmarking+our+performance/

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## ◆ National Grid Public Policy Strategy

As part of National Grid's public policy strategy, the Company works with regulators, legislators, community leaders and other stakeholders on issues of common interest. We strive to influence state and federal policy, as well as legislation or administrative action in a manner that allows us to continue to provide our customers with safe and reliable gas and electricity at the lowest possible cost while addressing the social, economic and environmental impacts of our activities.

There are a number of ways in which the Company tries to affect positive change in the form of policy, legislation or regulation. National Grid is staffed with personnel located in Washington, D.C. who closely monitor developments in these areas at the federal level. Personnel in all of the states in which we operate monitor developments at the state level. We attempt to work proactively with our legislators and regulators.

An example of where our public policy/lobbying efforts have proven to be successful is with respect to the Regional Greenhouse Gas Initiative (RGGI). As will be noted later in this report, while during FY07 we did not own generating assets, we nevertheless took a proactive approach in helping to shape the RGGI regulations in a way that would be most beneficial to our end use customers. There are other examples in this report of where we are actively trying to shape policy.

As part of National Grid's environmental program, there is a constant focus on new and pending legislation or regulations in the states in which we operate. While National Grid will act individually as a company in reviewing new legislation or regulation, it can have the most impact through its participation in various trade associations. Some of the organizations or associations in which National Grid is a member include:

- New York State Business Council
- Environmental Energy Alliance of the State of New York
- Utility Solid Waste Activities Group
- Edison Electric Institute
- Environmental Auditing Roundtable
- Energy Association of New York State
- Associated Industries of Mass.
- American Gas Association

Through these memberships, National Grid can track potential changes in legislation and ensure that our interests are represented in advocating certain positions.

The company also has in place GridPAC, a voluntary organization that provides financial support for political candidates who understand the concerns of utilities such as National Grid and who are supportive of our company and our industry. The GridPAC Executive Committee consists of a group of employees with very diverse backgrounds within National Grid who consider requests for campaign contributions from many members of various political organizations. The recipients of GridPAC funds are chosen based on their interest in, and impact on, issues affecting National Grid. Most of our support goes to members in our service area, but we also support like-thinking members nationwide. In calendar year 2006, contributions in the amount of $72,250 were made to GridPAC resulting in contributions to multiple fundraising efforts.

## Economic Performance

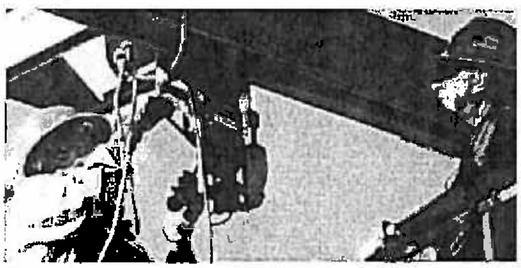
## ◆ Overview

National Grid has a focused approach to managing its businesses, keeping in mind its commitment to reliability, safety and environmental stewardship. Toward that end, the Company has developed a clear business model based on the ownership and operation of large-scale asset-intensive electricity and gas infrastructure in the United States and United Kingdom. Such a mindset led National Grid in 2007 to sell its wireless infrastructure operations in the US and UK and its Basslink Interconnector in Australia.

Flexibility plays a key role in National Grid's model. That includes considering ownership of generation assets where they are already part of a business and where they may fit the right risk profile, with limited exposure to commodity price fluctuations.

Another aspect of National Grid's economic goals is integration – more specifically, National Grid's determination to run its businesses in a more integrated fashion and organize itself along lines of business supported by effective shared services and information systems. In this way, National Grid plans to maximize the competitive advantages that come with being a large international organization.

National Grid applies a strong financial discipline to ensure that it has the capital to grow, while maintaining the investor confidence that comes from taking a disciplined approach to managing its balance sheet.



*Additional investment in the existing network will increase safety and reliability.*

National Grid's capital investment in its existing network continues to increase to meet infrastructure requirements. National Grid invested $4.09 billion during Fiscal Year 2007 compared with $3.7 billion in Fiscal Year 2006. Investment is being made in New England to deliver the regional expansion plan and in upstate New York to address asset replacement requirements and increase the network's safety and reliability.

To help set the direction for the next five to 10 years, National Grid undertook a thorough strategic review of its business. Market trends and opportunities were considered, as well as National Grid's market position, how it derives value from its businesses and the views of the capital markets. The review resulted in:

- Placing more focus on principal growth markets in the United States and United Kingdom
- Exiting the wireless business
- Developing a global operating model that includes improving efficiencies and completing the KeySpan acquisition and integration into National Grid
- Creating a simpler organizational structure
- Maintaining an efficient balance sheet
- Returning cash to shareholders

National Grid has made significant progress toward achieving these objectives and reshaping its strategic direction to create greater value for customers, shareholders, employees and other stakeholders.

As we move forward, National Grid will continue to look for opportunities for future acquisitions. In doing so, we will adopt long term sustainable practices as an integral part of any acquisition.

National Grid has an extensive Reliability Enhancement Program in place which entails not only replacement or repair of aging infrastructure, but also the installation of new infrastructures where needed. Through this program, we expect to dramatically improve long-term reliability for our customers.

National Grid believes that its long-term sustainability strategies are in sync with strong financial performance. An example is the Company's energy efficiency programs, which help reduce greenhouse gas emissions while reducing costs for our customers. As a forward-looking company, we will continue to look for opportunities to expand our energy efficiency programs.

**Financial Highlights**
National Grid reported positive financial results for Fiscal Year 2007, with a number of key performance indicators showing improvement. National Grid reports results in accordance with International Financial Reporting Standards as adopted in the European Union.

In assessing financial performance, National Grid analyzes metrics such as operating profit, profit before taxes, profit for the year attributable to equity shareholders, and earnings per share. Following is a breakdown of Fiscal Year 2007 performance:

| Fiscal Year 2007 performance (US dollars in millions) | |
|---|---|
| Revenue | [illegible] (down 2 percent) |
| Adjusted operating profit | [illegible] |
| Total operating profit | [illegible] (up 3 percent) |
| Cash generated from operations | $5,500 (up 4 percent) |
| Return on equity | 12.4 percent (three-year average) |
| Earnings per share | 85.6 (up 16 percent) |
| **Revenue by business segment was as follows (US dollars in millions)** | |
| Transmission UK | $5,012 |
| Transmission US | [illegible] |
| Gas Distribution UK | $2,123 |
| Gas Distribution US | $1,135 |
| Electricity Distribution US | $5,347 |
| US Stranded cost recoveries | $758 |

Note: For previous years' financial data, refer to the National Grid annual report located at www.nationalgrid.com.

On August 24, 2006, National Grid completed the acquisition from Southern Union Company of its Rhode Island gas distribution network for $526 million, including transaction costs of $5.3 million, together with the assumption of $85 million of debt. The acquisition expanded National Grid's gas distribution operations by 245,000 customers and added more than 3,000 miles of pipelines.

As part of its commitment to greater financial discipline, National Grid in Fiscal Year 2007 returned 169 million pounds to shareholders in a share buy-back program. The program arose from National Grid's decision to return $1.9 billion (1 billion pounds) based on the post-tax net amounts it expects to recover from US stranded costs. Moreover, National Grid has announced plans to return an additional 1.8 billion pounds in Fiscal Years 2008 and 2009 following the sale of its wireless infrastructure operations.

On April 3, 2007 National Grid completed the sale of its UK wireless infrastructure operations for $4.5 billion. It also announced its intention to sell the much smaller US wireless infrastructure operations for approximately $290 million (This sale has also been completed).

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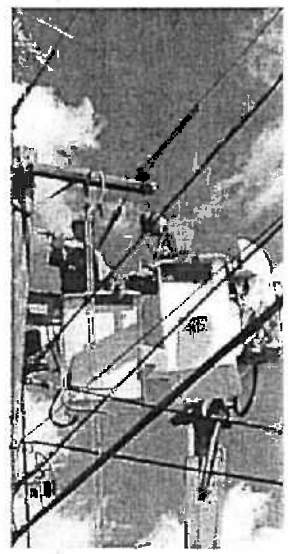
In August 2007, National Grid acquired KeySpan for $7.3 billion together with the assumption of approximately $4.5 billion of debt. The acquisition significantly expanded National Grid's operations in the northeastern United States, serving 2.6 million customers in New York, Massachusetts and New Hampshire. KeySpan also operates an electricity transmission and distribution network that serves 1.1 million customers in New York under a long-term contract with the Long Island Power Authority. The combination resulted in National Grid becoming the second largest energy utility in the United States in terms of number of customers served.

**Reliability**

Improving the reliability of electric service is one of National Grid's top priorities. To achieve its internal and regulatory goals in this important area, the Company made 2007 the Year of Reliability Focus. This far-reaching effort features a comprehensive reliability plan that includes continuation of its five-year, $750 million Reliability Enhancement Program – now in its second year. The Company's efforts include a system-wide program to replace older distribution assets, greater use of technology to identify and resolve problems, improved work practices, and a full range of incident-response improvements.

National Grid's Reliability Enhancement Program targets our poorest performing lines for immediate action. Over the next five years, the Company has committed additional capital and operating expenditures to improve electric reliability system-wide. Key elements include:

- *Line Hardening* – In Fiscal Year 2007, the Company hardened nearly 600 miles of lines in New York and 762 miles in New England. In Fiscal Year 2008, we plan to complete an additional 1,476 miles in New England and 1,388 miles in New York.
- *Vegetation Management* – In FY07, more than 4,098 miles in New England and 6,128 lines in New York were targeted for tree trimming and tree branch and shrub removal.
- *Subtransmission/Transmission Enhancement* – Projects include replacing outmoded reclosers (devices that isolate areas of interruptions) with breakers in several substations, adding reclosers on feeders to eliminate unnecessary outages or interruptions to customers far from the source of the outage, and launching a 23 kV cable replacement program.



*Line hardening is a significant component of the Reliability Enhancement Program.*

**Indirect Economic Impact**

National Grid has put in place formal systems to establish goals and track the economic impact of its activities in New England and Upstate New York. By virtue of these mechanisms the company can monitor the result of its initiatives over time.

***Economic Development Programs and Services***

Historically, National Grid in Upstate New York has operated a strong economic development program, focused primarily on the attraction of new businesses and expansion of existing customers in the service territory. National Grid partners regularly with state and local development organizations in these sales and marketing efforts which, since 2004, have resulted in the creation of 8,600 new jobs and $4.8 billion in new capital investment across Upstate New York.

In addition, New York State operates the Empire Zones program, created to stimulate economic growth through a variety of state, local, and utility incentives. National Grid has the most active, widespread utility discount program in New York, covering 40 state-designated Empire Zones dispersed across 29 counties of Upstate New York. In 2006 alone, over 1,600 National Grid customers received benefits under the program representing $15.9 million in discounts.

Finally, in 2003 National Grid supplemented its ongoing economic development efforts with the addition of a series of targeted grant programs designed to encourage new job creation and investment in Upstate New York. Collectively, the 14 programs have received 422 applications from new or growing businesses since 2003, and National Grid has approved 326 for total grant awards of more than $17 million. To date, these programs have helped lead to the creation or retention of nearly 11,000 jobs, $5.5 billion in new capital investment, and 8.9 million square feet of new or rehabilitated building space.

***Low Income Customer Assistance***

National Grid provides low income customers in its New England and Upstate New York service territories with rate discounts and credits to help offset their electric and gas costs. In 2006 National Grid provided this assistance to more than 236,000 of its customers.

In addition, National Grid offers a series of energy efficiency programs, typically in collaboration with state and local partners. These programs fund costs associated with weatherizing residential structures and replacing old or inefficient appliances with new, energy-efficient ones. In 2006 more than 16,000 customers in New England and Upstate New York were provided with energy efficiency assistance.

In partnership with the Salvation Army in New England (Massachusetts, Rhode Island, and New Hampshire) and the American Red Cross in Upstate New York, National Grid, its customers and employees annually contribute monies into the Good Neighbor and Care and Share funds, respectively. In 2006, these funds were used to provide over 8,300 customers in temporary crises with assistance to pay their energy bills.

National Grid also offers arrears management programs in both its New England and Upstate New York service territories. In 2006 more than 3,500 customers took advantage of these payment agreement programs in order to better manage their energy bills.

There are no established benchmarks for measuring the impact of National Grid's economic development or low income customer assistance programs. However, each functions within the environment set by the different state and local governments and regulatory agencies under which National Grid operates, and take into consideration the policies and priorities of our government, economic development and social services allies.

**Supplier Initiatives**

National Grid is a major purchaser of goods and services through its locations in both New England and New York. National Grid competitively bids materials and services to obtain quality goods or services at the best price. An important component of this bidding is the incorporation of environmental and social criteria into the bidding process.

National Grid expects all of its suppliers to comply with its environmental standards. Supplier work practices, equipment and services must meet or exceed our safety standards. National Grid thoroughly reviews the environmental and safety performance of its suppliers and includes compliance requirements in its purchase orders and contracts. While these measures are important to achieving a sustainable supply chain, we are committed to doing more.

National Grid has a significant opportunity to help diversify suppliers while strengthening the state and local economies in which we operate. We have a number of programs in place by which we are aggressively moving to diversify our suppliers and provide local businesses with opportunities to sell to us.

The United States electric and gas utility industry, which consists of more than 3,214 utilities, spends between $20 billion and $30 billion annually on equipment and construction. Although there are no US laws or regulations that require utilities to purchase from minority, women-owned enterprises, or businesses run by disabled veterans (MWBE), we recognize that this is an important component of our corporate responsibility program and, as a result, we are implementing a number of measures to increase purchases from or use of MWBE vendors.

Some of the initiatives undertaken include: meeting with various state diversity representatives, interviewing Top-10 inclusion and diversity companies to learn how they have increased their diversity supplier relationships, and developing a new business ownership standard to ensure maximum participation by qualified vendors. Procurement policies and procedures have been developed to include MWBE consideration as part of the vendor evaluation award process. We have also initiated a Tier II (Indirect) spending tracking program, whereby suppliers report National Grid purchases from the MWBE suppliers they use.

In Fiscal Year 2007, National Grid's MWBE spending was slightly less than $35 million, with 27 new vendors added to its program. Below is a chart summarizing FY07 results:

| MWBE Spending | | |
|---|---|---|
| Tier One – Direct | FY 07 | |
| Minority Owned Firms | $ [illegible] | |
| Women Owned Firms | $ [illegible] | |
| Total | $ [illegible] | |
| Tier Two – Indirect | | |
| Minority Owned Firms | $ [illegible] | |
| Women Owned Firms | $ [illegible] | |
| Total | $ [illegible] | |
| Total FY07 Tier 1 and Tier 2 | $ 34,947,[illegible] | [illegible] |

We also believe it is important to engage with external stakeholders to improve our procurement program. We are members of the New England Minority Supplier Development Council and the Upstate New York Regional Minority Purchasing Council. We are also fostering partnerships with the Greater Syracuse Chamber of Commerce, the Martin Luther King Development Center of Worcester, the Upstate Business Council of Rochester and the Minority Supplier Development Business Expos.

Furthermore, National Grid sees human rights as an important part of its business strategy, including its relationship with suppliers. In May 2003, the National Grid Board approved a Public Position Statement on Human Rights. In accordance with the Position Statement, supply chain management teams have received basic human rights training and have carried out an initial assessment to establish if and when there might be human rights issues in our supply chain. National Grid is in the process of developing a human rights questionnaire for US suppliers; coupled with the questionnaire will be an identification of the human rights expectations National Grid has. Procurement staff has been, and will continue to be, trained on the human rights elements of our supply chain program.

National Grid also maintains a commitment to local businesses. This support enhances the growth and development of local firms and stimulates economic growth within our service territory. National Grid has in place the following policies to provide support for the local business community:

- National Grid may not elect to solicit bids from suppliers or contractors outside its franchise territory if adequate competition exists within its franchise territory.
- National Grid will provide the opportunity to qualified local suppliers or contractors to bid. When price, quality, quantity, delivery, and other factors are essentially equal, National Grid will give preference to local businesses.

Looking ahead, National Grid will move forward its procurement strategy in Fiscal Year 2008 in a number of ways. Key components of the strategy include: training, implementation of the human rights questionnaire and outreach program, further goals in improving the number of MWBE suppliers, and a targeted communication plan to employees regarding our procurement practices.

# Environmental Performance

## ◆ Overview

National Grid has made environmental stewardship a top priority. The Company is committed to mitigating climate change and conserving natural resources as it delivers electricity and natural gas in a safe and reliable manner. To achieve this objective, National Grid has made investments and committed resources – empowering its people accordingly.

Environmental stewardship in the United States is a key element of National Grid's culture. The Company is committed to protecting birds, fish and other wildlife, developing renewable energy programs, restoring brownfield or impaired legacy sites, managing trees and plants wisely, and raising environmental awareness throughout its service territory – 29,000 square miles of Massachusetts, New York, New Hampshire, Vermont and Rhode Island. Employees are trained to include the environment in their plans and programs.

Moreover, National Grid has implemented a Company-wide climate change strategy aimed at producing a low-carbon business model that reduces carbon dioxide ($CO_2$) and other greenhouse gases, promotes renewable energy, and supports regional and federal legislation to cut greenhouse gas emissions in all sectors of the economy. As part of this climate change initiative, National Grid is committed to helping its more than four million residential and commercial customers use electricity and natural gas wisely to help them save money and enable the Company to reduce emissions associated with energy use.

What follows is a report of National Grid's commitment to the environment.

## ◆ Environmental Management System


National Grid's Environmental Management System guides us through our daily operations in a manner that is protective of the environment. We strive to improve our system through different means, including policies, third-party review and employee training.

**Environmental Policy**
The guiding document for our Company's environmental program is our environmental policy. We are committed to the protection and enhancement of the environment and strive for new ways to minimize the environmental impacts of our past, present and future activities. We also hold our employees accountable for good environmental performance as we incorporate environmental considerations into all of our business activities. As such, training is an important part of our Environmental Management System.

The basic components of the Company's environmental policy are as follows:

- National Grid will meet, and where appropriate, exceed the requirements of legislation, policies, charters and other commitments to which we subscribe.
- National Grid will prevent pollution, including the releases of oil and hazardous materials, wherever we can.
- National Grid will minimize and properly manage the waste we generate and reuse or recycle waste whenever economically feasible.
- National Grid will provide visible leadership that promotes good environmental performance.
- National Grid will help protect the environment for future generations by making our contribution to minimizing climate change.

Our environmental policy statement is publicly available and can be found at www.nationalgridus.com.

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**CERES**

In 2006, the Company made the decision to join CERES. National Grid is one of the first Northeast utilities to join this organization. CERES is a leading coalition of investors, environmental groups and other public interest groups working with companies to address sustainability challenges. CERES has more than 70 companies in its network, including 18 Fortune 500 companies. While National Grid currently has a strong Environmental Management System in place, we anticipate participation in CERES will further enhance our sustainability efforts.

**ISO 14001**

While having in place a strong Environmental Management System is important to driving sustainable performance for any company, its full benefits cannot be appreciated without a third-party review. That's why National Grid made the decision to adhere to the International Standard for Environmental Management Systems, ISO 14001, in the late 1990's. Since we made that decision, our entire transmission and distribution system, as well as the Investment Recovery facility, have been certified to the standard by an independent accredited registrar, Advanced Waste Management Systems.

We believe the combination of our environmental policy, review of our Environmental Management System by an independent registrar and stakeholder engagement provided by CERES will help move our environmental and sustainability program forward.




## ◆ Environmental Goals

As part of National Grid's environmental management system, goals are set annually to further the program. National Grid made progress in Fiscal Year 2007 in achieving its environmental goals, which focus on a range of activities from climate change and compliance to training and reporting. Set forth below is a brief summary of our goals. Details are provided later in the report.

**ISO 14001 Conformance**

A key Fiscal Year 2007 goal was to maintain ISO 14001 conformance. This required review and modification, as necessary, of National Grid's transmission and distribution system and Investment Recovery Environmental Management Systems (EMS). Key elements included reviewing Company operations to ensure significant environmental impacts were identified, setting objectives and targets, and reviewing the performance of the EMS. In addition, other company functions besides transmission and distribution were also incorporated into the registered EMS.

*Actions taken included:*

- Completed internal and registration audits for Investment Recovery.
- Updated the Company EMS Manual and procedures to reflect changes and improvements.
- Incorporated Property Assets and Legal departments into registered EMS.

***Release Reporting.*** Evaluating New York spill reporting procedures in each of the divisions was another goal. State regulations require oil spills to be reported within two hours of discovery. Failure to report within that time can result in a Notice of Violation and associated monetary fines.

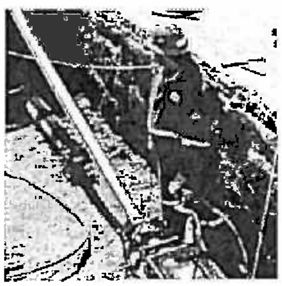
In response, National Grid evaluated reasons for errors in release reporting, using historical records and interviews to gather data. Reasons identified include issues related to training, spill ownership definitions, communication errors and incorrect reporting times. A summary memorandum was prepared to document the results of the evaluation and changes were recommended to internal environmental procedures.

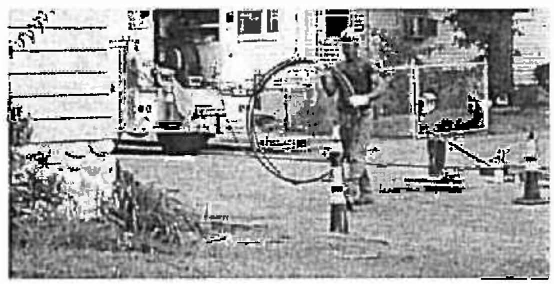
***Underground Storage Tank (UST) Removal.*** This was another major environmental goal where substantial progress was achieved.

- All USTs in New England and New York have been removed and all replacement above-ground storage petroleum tanks (ASTs) have been installed and are operating.

***Spill Prevention Control and Countermeasure (SPCC) Regulations.*** National Grid targeted a program for SPCC plans to meet revised regulatory requirements in its Fiscal Year 2007 goals. The most recent SPCC rules were published in December 2006. They provide flexibility to utilities for storage of electrical equipment to use a "strong contingency plan" in lieu of installing secondary containment. The compliance date has been extended to 2009 to put such plans in place or install secondary containment. National Grid's Environmental Department evaluated the new rules and developed recommendations for future SPCC plan implementation requirements, which have been approved by senior management.

To help reduce carbon dioxide releases, nearly 100,000 feet of gas main were replaced.





***Global Climate Change.*** In the area of global climate change, National Grid set a goal of reducing equivalent carbon dioxide ($CO_2$) releases from gas mains by 3,873 tons. Actions included reducing methane leakage from the New York Gas System by completing 75 percent of the following planned programs:

- Replacing 120,000 feet of cast-iron gas pipe
- Applying cathodic protection to 40 miles of unprotected steel gas mains

The results were significant: 47 miles of steel were protected and approximately 98,749 feet of main were replaced due to age and deterioration. More importantly, the goal of reducing the 3,873 tons of $CO_2$ equivalent was achieved. These goals further our long-term goal to reduce greenhouse gas emissions by 60% by 2050.

***Greenhouse Gas Initiative.*** Other climate change-related targets included continued participation in the Regional Greenhouse Gas Initiative (RGGI) to shape a $CO_2$ emissions trading system that will be fair to electric customers (a more detailed discussion is provided later in the report); support for the Global Climate Change Initiative; and continued implementation of a long-term strategy on sulfur hexafluoride ($SF_6$).

*Aspect Evaluation.* This included completing the first year of a multi-year program to review all environmental media to ensure regulatory compliance. Key elements were:

- Identifying all solid and hazardous waste streams and ensuring that any unique processes, justifications or analyses are documented and retrievable.
- Identifying unique situations where permits or regulatory requirements do not apply, based on analysis or regulatory interpretations, and ensuring that the process is documented and retrievable.
- Developing a schedule for completing this review for all other environmental media, such as air, wetlands and water.

*Environmental Training.* National Grid's Environmental Training goal produced results as follows:

- Personnel requiring environmental training were provided with training.
- Environmental awareness and compliance training were added to the Infonet (National Grid's intranet) for those employees who only need general awareness training.
- A Department of Transportation video was taped and made available for training programs and put on the Company's intranet.

*Regulatory Requirements.* With regard to compliance with regulatory requirements, National Grid achieved the following:

- Environmental Audit completed its schedule for the Fiscal Year 2007 audit plan.
- 22 of 26 audits were started.
- 22 audits were issued as final during the fiscal year; 4 additional final reports were issued during the first and second quarters of Fiscal year 2008.
- The Fiscal Year 2008 audit plan was developed and implemented.

**Site Investigation and Remediation Program**

In the area of site investigation and remediation, National Grid took actions as follows:

- Completed seven environmental investigations.
- Selected clean-up (remediation) strategies for three sites.
- Completed seven remedial designs and remediations.
- Completed work at four sites.

National Grid also continued to aggressively pursue cost-effective remediation strategies through careful engineering and science-based solutions. One important accomplishment includes significant progress on sediment toxicity programs.

**Fiscal Year 2008 Goals**

For Fiscal Year 2008, National Grid's environmental goals consist of:

- *ISO 14001 Conformance* – Reviewing and modifying as necessary the National Grid Environmental Management System to maintain ISO 14001 conformance. Actions include incorporating the Rhode Island gas operations into the EMS Registration, developing a plan and schedule for incorporating KeySpan functions into the EMS and ensuring consistency of the EMS with other asset management systems.
- *Release Reporting* – Minimizing Category 1 incidents.
- *Communication* – Providing resources to enhance communication and relationships with interested parties.
- *Global Climate Change* – Complete at least 75 percent of planned replacements and achieve an annual reduction in methane emissions of 5,091 million cubic feet or 2,057 tons of $CO_2$ equivalent; replace 150,000 feet of cast iron gas pipe and apply cathodic protection to 53 miles of unprotected steel gas mains. Other climate change goals include supporting the Global Climate Change Initiative, supporting and implementing the long-term strategy on sulfur hexafluoride, and achieving 232,723 MWh in annualized energy savings from energy efficiency program efforts in Massachusetts, Rhode Island and New Hampshire.

- *Aspect Evaluation* – The goal is to continue the review of a multi-year program to review all environmental media to ensure compliance with regulatory requirements.
- *Environmental Training* – Goals include offering ENV-200/250 training to all personnel who require environmental training, offer environmental awareness training (ENV-100) to employees who only need general awareness training, and completing Department of Transportation training for hazardous materials.
- *Regulatory Requirements* – The goal is to complete environmental audits (compliance, management systems, vendors) per the audit schedule.
- *Site Investigation and Remediation* – The goal is to communicate to the regulatory community new information regarding the reduced bioavailability of contaminants in sediments in the soil.

## ◆ Climate Change

Adverse effects of climate change associated with the release of greenhouse gases may result in legislation or regulation requiring industry and especially electric utilities to reduce greenhouse gas emissions from power plants and other sources. Additionally, National Grid is strongly committed to operating in a sustainable manner in order to protect the environment and the earth's natural resources for future generations. National Grid believes that the potential impact of long-term climate change on the electric and gas utility industry presents long-term challenges. National Grid believes that substantial business opportunities also exist. As the result, the Company has embarked on a Global Climate Change Initiative employing a number of strategies to evaluate and plan for the potential impacts associated with climate change on the Company and society as a whole.

**National Grid Global Climate Change Initiative**
The National Grid Global Climate Change Initiative aims to achieve the target of a 60 percent reduction of greenhouse gas emissions from 1990 levels by 2050 through a combination of efforts. This Initiative was adopted by our Board of Directors in May of 2006 and has been taken up by all areas of our business in the US and the UK. Since that time, we have realized that this Initiative, which focused on company efforts to reduce its greenhouse gas emissions, did not recognize the opportunities of involving our customers, employees or regulators in such a strategy. In addition, the ever evolving science of climate change, probably best summarized in the recent publications of the Inter-Governmental Panel on Climate Change (IPCC), leads us to believe that as a responsible company we must take a leadership role in this area.

As of the publication of this report, National Grid has embarked on a review of this strategy and adopted an enhanced approach to dealing with climate change and the unique role we can play in this area.

This enhanced approach will continue the existing efforts by the company to mitigate its emissions of greenhouse gases but also begin to expand these efforts in such areas as exploring ways of further mitigating the $CO_2$ emissions from the recently acquired electric generating plants of KeySpan. In addition, we will be taking measures to make our operations more sustainable by incorporating procedures to consider carbon impacts and require mitigation of these impacts in business decisions, greening our supply chain and working with academic institutions to better understand climate change. We also hope to begin to reshape energy markets through initiatives such as negotiating rate decoupling mechanisms for our distribution companies, working to move energy dispatch towards low carbon generation, implementing smart metering within our service territories and providing means by which our customers and employees can begin to mitigate their emissions of greenhouse gases.

As part of our existing initiative, in the United States we are targeting to reduce sulfur hexafluoride ($SF_6$) leakage, replace gas mains, continue to expand our re-conductoring activity, engage in renewable energy initiatives and replace specific portions of our vehicle fleet with higher fuel economy vehicles by 2009.

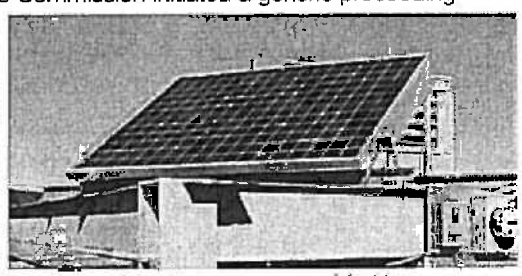
What follows is a discussion of measures National Grid is implementing to shape sensible state and federal policies, and strategies to reduce its direct and indirect emissions.

**Working with State and Federal Officials to Develop Sensible Policies**

**1. Regional Greenhouse Gas Initiative** — National Grid is part of a cooperative effort by Northeastern and Mid-Atlantic states in reducing $CO_2$ emissions from large power generation facilities. The program, known as the Regional Greenhouse Gas Initiative (RGGI), recently issued a model rule aimed at capping and ultimately reducing $CO_2$ emissions from fossil-fired power plants within the Northeast. Although National Grid has not owned or operated fossil-fired plants, it has chosen to participate in this initiative because it is important for the environment and it will impact the cost of the electricity to its customers. The company wants to ensure that its customers are treated fairly in the Regional Greenhouse Gas Initiative process. Beginning in 2009, all fossil-fueled power plants that produce 25 megawatts or more of electricity in the seven participating states are required to cap their $CO_2$ emissions, and beginning on January 1, 2015, reduce their emissions overall by 10 percent through 2019. National Grid continues to lobby to protect the interests of its customers. We are also monitoring the RGGI leakage report and its recommendations.

**2. Decoupling** – Decoupling is a measure employed to remove the disincentives for utilities to promote energy efficiency and other demand resources. Decoupling breaks the link between utility revenues and sales levels. National Grid is in favor of such a mechanism. Structured correctly, it aligns shareholder and customer interests to provide for more economically and environmentally efficient resource decisions.

National Grid is actively supporting decoupling mechanisms in the various states in which it operates. In New York, following the generic decoupling proceeding with the Public Service Commission, the PSC issued an order dated April 20, 2007 requiring that each utility in the state include a decoupling mechanism as part of its next rate plan. In New Hampshire, the Public Utilities Commission initiated a generic proceeding as well. Technical sessions have been held and expert testimony was provided in November 2007. Finally, in Massachusetts' generic proceeding, a wide range of stakeholders have provided comments. Hearings were held in late October 2007. In its comments, National Grid recommended that the Massachusetts regulator implement lost base-revenue mechanisms as an interim way to enable the ramp-up of energy efficiency and other demand response programs, and then move to fully decoupled rates on a permanent basis.



*The National Grid Global Climate Change Initiative aims to reduce greenhouse gas emissions 60 percent from 1990 levels by 2050.*

Moving forward, National Grid will continue to be an active proponent of decoupling in the states in which it operates.

**3. Federal Legislation** — Clearly there is a need for national policies to address the long-term effects of global climate change. As a result, National Grid has closely monitored proposed national legislation and has advocated for certain key components. The Company recently developed a position statement on the appropriate components of any federal legislation to reduce greenhouse gas emissions. The position statement is set forth below.

"National Grid sees climate change as presenting both challenges and opportunities. We will be challenged by the need to reduce our greenhouse gas emissions to assist global efforts in mitigating climate change, while at the same time adapting our large network to the consequences of climate change. We also recognize there is a growing opportunity to expand our business in other areas that will benefit both our customers and shareholders. With that said, there is a need for national legislation to address, in a consistent and comprehensive fashion, climate change issues. We believe such federal action or legislation should call for reduction of greenhouse emissions that:

- Involves all sectors of the economy and all types of greenhouse gas emissions.
- Establishes a mandatory national policy to contain and reduce US greenhouse gas emissions.
- Provides for a market-based approach to greenhouse gas reductions. Trading should be allowed across state boundaries as well as provide the potential for international trading.
- Requires that $CO_2$ emissions should be auctioned to sources and that all auction proceeds are distributed to end-use customers in the form of direct rebates and/or expanded energy efficiency programs.
- Recognizes early actions or investments made to mitigate greenhouse gas reductions. Further, companies that invest in technology that reduces emissions of gases not covered by a trading program should receive some incentive (i.e., enhanced capital allowances) in recognition of their proactive efforts.
- Establishes the United States Environmental Protection Agency (EPA) as the agency responsible for the administration of this program.
- Incorporates a robust, verifiable offset program.
- Provides incentives to accelerate the development of cost-effective energy efficiency programs and technologies and to stimulate growth and promote the establishment and development of greenhouse gas-reducing technology, including supportive tax policies. Such incentives should be structured around energy efficiency and security of supply and reliability.
- Provides incentives to companies to evaluate the long-term adaptability of their products or services to climate change.
- Realigns national energy and transportation policies to stimulate research, development, and deployment of existing and new clean technologies on the scale necessary to reduce greenhouse gas emissions and eliminate incentives or technologies that exacerbate climate change. Legislation should recognize the current energy mix which includes coal, and should provide incentives for the development of lower emitting coal technologies.
- Contains a mandatory reporting program established in coordination with the Securities and Exchange Commission on what material issues companies should disclose in their regular financial reporting.

While the debate continues, we believe the above are important components of any national legislation that is put into place."

**National Grid US Climate Change Workgroup**

In order to manage the various climate change requirements and to achieve a consistent approach to this issue throughout National Grid's US operations, a workgroup has been established. The workgroup, which is intended to act as the central clearinghouse for all climate change issues, meets periodically to:

- Discuss regulatory and legislative developments
- Develop and/or review company policy
- Report on a semi-annual basis to senior management regarding achievement of various climate change goals and commitments

All areas of the Company that may have an interest in climate changes issues or whose operations may potentially impact the earth's climate are represented in the workgroup. Among the departments currently participating are:

- Environmental
- Transmission
- Substation O & M
- Fleet
- Facilities
- Technology Transfer
- Demand Side Management
- Legal
- Gas
- External Affairs

National Grid expects to increase both the scope and constituency of the workgroup as a result of enhancements to our Climate Change Initiative.

**Reporting our Impacts**

**1. Voluntary Reporting Program** — National Grid continues to be involved in a program that recognizes utilities for demonstrating a commitment to voluntary approaches to reduce or capture greenhouse gas emissions. The program is known as the Energy Information Administration's (EIA's) Voluntary Reporting of Greenhouse Gases Program. National Grid has reported annually under this program since 1993. Our enhanced approach will also result in our evaluating other greenhouse gas reporting platforms such as The Climate Registry.

Some of the reductions reported are direct, i.e., emissions for which National Grid is directly responsible. Methane emissions from natural gas distribution system leaks are an example. Other emissions reductions are indirect, for example, reducing electric transmission line losses by reconductoring, which in turn reduces the demand for electricity generation and ultimately requires less fossil fuel consumption. National Grid estimates that for 2006, its efforts have reduced emissions of carbon dioxide by over 29,000 tons, methane by over 120 tons, sulfur hexafluoride by 7,400 pounds and various refrigerants by over 2,400 pounds. Major project categories include electric line reconductoring; replacement of leaking natural gas distribution piping; recycling of metals, glass, plastics and paper; and energy efficiency.

For a review of trended $CO_2$ emissions, please refer to the Key Performance Indicator Chart at the end of this report.

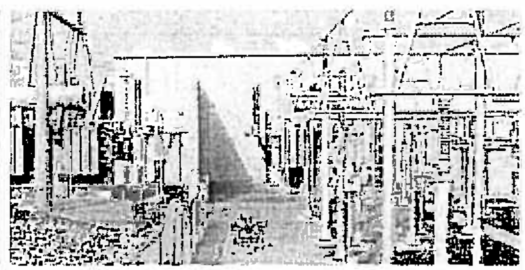
**2. Natural Gas Star Program** — Since 1994, National Grid has been working with other natural gas transmission companies enrolled in the voluntary EPA STAR Program to identify and adopt cost-effective technologies and practices to reduce emissions of methane. The primary component of natural gas, methane is 21 times more potent as a greenhouse gas than carbon dioxide ($CO_2$). In addition to adopting STAR Program best management maintenance practices to reduce methane emissions, National Grid is replacing older, leaking natural gas main and service piping. This leakage is the main contributor to methane emissions within the natural gas distribution companies in the United States. Set forth below is a chart showing natural gas pipeline replacements at National Grid over the past three calendar years, as well as the methane releases eliminated as a result of such replacements.

**Natural Gas Pipeline Replacement, Eliminated Releases (reported on a calendar year basis)**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| Miles of Pipeline Replaced | 48 | 33 | 19 |
| Natural Gas Releases Eliminated, Mcf | 8,864 | 5317 | 4503 |
| Natural Gas Releases Eliminated, Tons | 186.8 | 112 | 95 |

**Note:** Factors for eliminated releases of Natural Gas vary based on type and size of pipe replaced.

**3. $SF_6$** — Another significant initiative in which National Grid has been involved relates to $SF_6$. Sulfur hexafluoride ($SF_6$) is a nonflammable, nontoxic gas that has superior cooling, insulating, and arc-quenching capabilities in high-voltage electrical equipment. When $SF_6$ escapes into the atmosphere, it becomes a potent greenhouse gas with global warming potential that is 23,900 times greater than $CO_2$ over a 100-year period.



*Views of the upgraded and expanded Ward Hill substation in Haverhill, Mass.*

Nearly 80 percent of the $SF_6$ produced today is used by the power industry. National Grid uses more than 140,000 pounds of the gas in electric substations and breakers throughout the Northeast to ensure the reliable and safe delivery of electricity to our customers. That usage prompted our subsidiaries to join the Environmental Protection Agency's voluntary $SF_6$ Emission Reduction Partnership.

New York operations enrolled in 1999, as one of the first participants in the program that tracked and reported releases of $SF_6$ on an annual basis. National Grid's New England subsidiaries joined in December 2003. To achieve the Company's goal of 57 percent reduction in $SF_6$ emissions from 2000 levels by 2008, we are targeting replacement of first-generation gas insulated substations (GIS) having older $SF_6$ gas circuit breakers. We are also monitoring $SF_6$ uses more aggressively to identify and prioritize leaking equipment, using conventional methods and advanced laser imaging technology. In addition, we are training employees on proper gas handling procedures and on properly recording $SF_6$ returns to gas vendors.

Set forth below is a chart identifying historical $SF_6$ Usage and Inventory:

**Historical $SF_6$ Usage and Inventory**

| Year | Loss in Pounds | Loss Rate | Nameplate Capacity |
|---|---|---|---|
| 2004 | 12,471 | 8.9% | 140,061 |
| 2005 | 12,316 | 8.9% | 137,760 |
| 2006 | 12,249 | 8.1% | 150,818 |

**4. Our Fleet** – Vehicle tailpipe emissions contribute to health and environmental problems such as urban smog, air toxins and global warming, according to the US Environmental Protection Agency. This is why National Grid's Fleet Management has taken aggressive measures to reduce greenhouse gas emissions.

Some of the environmentally friendly habits Fleet Management has incorporated into its operations include replacing older vehicles with more fuel efficient ones. This increases fuel economy and decreases pollutants. In addition, Fleet Management provides utilization information to Operations so that they can retire under-utilized vehicles, which will result in lower fuel consumption. But that's not all they're doing.

Currently, National Grid has four hybrid automobiles in service and one hybrid bucket truck on order. An added bonus is the operator's platform (bucket) can remain operational on battery power for up to two hours without having to turn on the vehicle's engine. The truck can be fully recharged in less than ten minutes.

In another significant effort, National Grid provides bio-diesel at all company fuel tanks during warm months.

National Grid US has also informed its employees that they can do the following to help:

- Limit unnecessary vehicle idling
- Car pool or share rides
- Avoid stop-and-go driving
- Avoid topping-off when refueling their vehicle. Spilled gasoline pollutes the air when it evaporates

**5. Our Facilities** – In 2005, the Facilities department embarked on an initiative to make heating, ventilation and air conditioning (HVAC) improvements in the Westborough Mass. building, which resulted in a 25 percent reduction in electricity consumption. The department also developed a detailed plan in support of the Global Climate Change Initiative including a review of electrical and natural gas consumption at all locations managed by Facilities and cost effective actions that can be taken to reduce consumption.

Facilities' strategy also calls for moving toward using a 100 percent renewable electricity source in the Westborough building by 2010.

**Indirect Impacts**

**1. Programs Promoting Energy Efficiency and Conservation** – Electricity customers of National Grid have a broad selection of programs to aid them in becoming more efficient in their use of electricity. In addition to conserving energy, these programs save customers money and reduce the emissions that are byproducts of energy production.

More than half of our 1.7 million New England electric customers have taken advantage of these programs since 1987. Our residential programs reached over 300,000 homeowners and tenants, and our business programs have served an average of 3,000 businesses each year for the period from 1998 through 2007.

An example of National Grid's leadership in this area was Rhode Island Governor Donald L. Carcieri's proclamation on October 16, 2007, as "National Grid Energy Efficiency Day." He commended National Grid for its leadership in helping to improve the quality of life for citizens by demonstrating the importance of energy efficiency, helping customers to take control of energy costs and assisting customers in offsetting greenhouse gases that contribute to global climate change.

In addition, National Grid's energy-efficiency programs were recently named among the nation's best by the American Council for an Energy-Efficient Economy (ACEEE). National Grid received honors for 10 programs, the largest number of awards received by a company in the Northeast.

The following energy-efficiency programs offered by National Grid in New England were recognized for effectiveness and innovation in helping customers achieve greater levels of energy efficiency in 2007 in their homes, businesses, and facilities:

- Appliance Management Program
- Energy*Wise*
- Energy Initiative
- Design 2000Plus
- Home Performance with ENERGY STAR®/MassSAVE
- Northeast ENERGY STAR® Lighting and Appliance Initiative
- Small Business Services
- Advanced Buildings
- Whole Building Assessment/Benchmarking
- GasNetworks

"ACEEE conducted this national review to recognize outstanding energy efficiency programs and honor the people and organizations responsible for their success," explained Dan York, Ph.D., the ACEEE Project Director for this effort. He added: "Programs such as National Grid's demonstrate the very real value of energy efficiency to the customers it serves."

Martin Kushler, Ph.D., ACEEE's Utilities Program Director said, "These programs are delivering energy savings that are critical in helping customers cope with today's high energy costs, plus they make an important environmental contribution because they help reduce greenhouse gas emissions." He added, "This is truly a 'win-win' situation."

Since the company began offering energy-efficiency programs in 1987, participating customers have saved more than $2.5 billion and more than 26 billion kilowatt hours of electricity – enough to power approximately 4.3 million homes for one year. The programs also have reduced greenhouse gas emissions by more than 14.5 million tons, the equivalent to removing 1.8 million cars from the road. Massachusetts' Governor Patrick and New Hampshire's Governor Lynch joined Governor Corcieri in honoring National Grid's energy efficiency programs by providing citations to the company for its excellent work in this area.

As we move forward as a larger, more robust National Grid as a result of the merger, energy efficiency measures will continue to be an integral part of National Grid's Global Climate Change Initiative.

To obtain more information about National Grid's US's wide range of energy efficiency programs in the US and how to participate, visit the National Grid website at www.nationalgridus.com.

**2. Forward Capacity Markets** — ISO New England, the power system operator for New England, will open its Forward Capacity Market (FCM) in June 2010. The auction to provide needed electrical capacity to meet growing customer demand will be in February 2008. The rules for the FCM auction have been developed to give energy efficiency and other demand-side resources the opportunity, for the first time, to compete on equal footing with generation to meet New England's supply needs. National Grid is preparing to bid the demand savings for its portfolio of programs into the market. The qualification of energy efficiency to meet the region's supply needs may advance energy efficiency in three ways. First, revenue paid to energy efficiency projects that clear in the auction may be reinvested in further energy efficiency. Depending on the clearing price, we estimate that first year revenues in 2010-11 may add about 6 percent to 10 percent to current program funding levels. Second, because the FCM is designed to promote capacity development, it is possible that program budgets will be reoriented to provide more demand savings. Third, available revenue streams may inspire non-utility providers of energy efficiency (such as energy supply companies) to increase their efforts to develop energy efficiency projects, and increase this type of energy efficiency in the region.

**Renewable Energy Programs**

Renewable energy utilizes natural resources such as sunlight, wind, tides and geo-thermal heat, which are naturally replenished. Renewable energy technologies range from solar power, wind power, and hydroelectricity to biomass and biofuels for transportation. About 13 percent of primary energy comes from renewables, with most of this coming from traditional biomass such as wood-burning. Hydropower is the next largest source, providing 2–3%, and modern technologies such as geothermal, wind, solar, and marine energy together produce less than 1% of total world energy supply. The technical potential for their use is very large, exceeding all other readily available sources.

Climate change concerns, coupled with high oil prices and increasing government support are driving increasing renewable energy legislation, incentives and commercialization. Investment capital flowing into renewable energy climbed from $80 billion in 2005 to a record $100 billion in 2006. National Grid views renewable energy as an important component of its Global Climate Change Initiative. Set forth below is a discussion of how we are trying to advance renewable energy.

**1. GreenUp** – On April 9, 2007, the US Department of Energy's National Renewable Energy Laboratory (NREL) named National Grid's renewable energy program, GreenUp, to its Top 10 ranking of utility green power programs. Using the information provided by utilities, NREL develops Top 10 rankings of utility programs in categories that include total sales of renewable energy to participants and total number of customer participants. GreenUp ranked 8th in both categories out of 600 utilities across the United States that offer green power programs. Almost 24,000 National Grid customers in New York, Massachusetts, and Rhode Island had purchased more than 156 million kilowatt-hours of renewable energy through GreenUp as of December 2006. GreenUp requires participating renewable energy providers to secure renewable energy sources – such as wind, bio-energy, or hydropower. After a customer selects a renewable energy provider, that provider notifies the utility of the customer's decision.

National Grid's supply portfolios receive the renewable energy credits on behalf of the customer, and the Company remains responsible for all service to the customer. Costs and other program details for GreenUp vary by state and provider.

**2. Renewable Energy Trust Fund** – National Grid supports and contributes to the Massachusetts Renewable Energy Trust Fund. Created in 1997, the Trust is charged with accelerating the use of cleaner sources of electricity in Massachusetts by investing in the state's renewable energy industry. Technologies include solar, wind, biomass, small hydro and fuel cells. A National Grid executive serves on the board of directors of the Massachusetts Technology Collaborative, the non-profit economic development organization that administers the Trust. In addition, a National Grid principal engineer has served since 2000 on several advisory boards regarding solar photovoltaic (PV) systems and fuel cells. Current work is focused on simplifying the process for utility interconnection of PV or wind-powered energy systems on underground network distribution systems, the type commonly found in the center of large metropolitan centers. Funding for the Trust comes from a monthly charge to electricity customers in Massachusetts.

**3. Renewable Research** – National Grid US continues to conduct research into renewable technologies. Examples of its efforts include:

- Photovoltaic systems and component research
- Renewable energy and storage project
- Residential scale wind turbine project at U Mass – Lowell

**4. Renewable Portfolio Standard** – Across the United States, 25 states and the District of Columbia have implemented some form of a state Renewable Portfolio Standard (RPS) to ensure that part of consumers' electricity comes from renewable energy sources. Massachusetts, Rhode Island and New York each have instituted RPS obligations.

In Massachusetts, the RPS mandated that retail electric suppliers purchase 1 percent of their energy from renewable resources beginning in 2003. That percentage increases one-half percent each year until 2009, when it reaches 4 percent. Because National Grid purchases electricity for many of its customers, the Company is covered by the mandate.

In Rhode Island, entities that sell electrical energy to end-use customers need to purchase 3 percent of their energy from renewable sources beginning in 2007, which gradually will rise to 16 percent in 2019. Because National Grid purchases electricity for many of its customers, the Company is covered by the mandate.

Both Massachusetts and Rhode Island allow for compliance through a number of means, including through making payments to state agencies which will use the payments to support renewable resources.

In New York, the Public Service Commission wants 25 percent of the energy used in the state to come from renewable sources by 2013. New York already produces 19 percent of its energy from renewable sources, nearly all from hydropower. The New York State Energy Research and Development Authority is the agency that facilitates auctions and enters into contracts for the renewable attributes of qualifying generators.

**ENERGY STAR™**

ENERGY STAR™ homes incorporate the latest technologies for energy efficiency and comfort. In National Grid's service territory, 15% of the new housing market is now building to ENERGY STAR™ standards, which are 15% more energy efficient than current building codes. The program also provides additional assistance to low income subsidized housing development, and works closely with Community Action Programs and low income energy efficiency advocates, Community Development Corporations, Habitat for Humanity, and the state and federal government to support sustainable energy efficient, affordable housing.

National Grid is an active ENERGY STAR partner and has contributed significantly to this program by providing rebates to residential customers who purchase Energy STAR appliances and lighting. This has helped to raise awareness of ENERGY STAR through advertising and contribute to ENERGY STAR standards in new homes. For eight consecutive years, through 2007, National Grid has received the US Environmental Protection Agency/Department of Energy ENERGY STAR Award for its appliance and lighting program. In 2007, National Grid also received the award for its MassSAVE program.

**University of New Hampshire Study**

National Grid believes that the potential impacts of long-term climate change on the electric utility industry require serious consideration, particularly with respect to the effect on the utility's existing infrastructure. As a result of these concerns, the Company is collaborating with the University of New Hampshire on a research project that will evaluate the effects of long-term climate change on our infrastructure, particularly in areas where we have facilities located next to water bodies. This project will involve the identification of specific vulnerabilities in the transmission and distribution system of the northeastern United States, the quantification of their likely severities, and the development of mitigation strategies to address the most critical vulnerabilities.

## ◆ Electric and Magnetic Fields Program

Electric and Magnetic Fields (EMFs) are another important environmental issue that National Grid is addressing. EMFs can be generated from a variety of sources, including our distribution and transmission power lines. Because of public concern, we take these issues seriously.

National Grid recognizes that there is some scientific evidence suggesting certain adverse health effects are linked to electric and magnetic fields. There is also evidence linking an increased risk of certain diseases to proximity to power lines, though the cause is not clear. The balance of evidence remains against both radio-frequency and radiofrequency electric and magnetic fields causing ill health.

The World Health Organization has classified power-frequency magnetic fields as "possibly" carcinogenic. National Grid's recently updated Public Position Statement on EMFs (which can be found at www.nationalgrid.com) helps set the framework within which we continually assess the scientific evidence in this area, determine any implications for the way in which we conduct our business, and explain to society what the science is telling us.

In all our operations, as a minimum, National Grid seeks to comply with regulations, guidelines or practices relating to EMFs in the different jurisdictions in which we operate. Where other companies, such as telecommunications operators, use our assets, we require them similarly to comply with the relevant regulations, guidelines or practices.

In the United States, National Grid has personnel who are trained to respond to customer inquiries and, when appropriate, measure EMF in customer locations and along our transmission and distribution lines.

## ◆ Waste Minimization

As part of its environmental activities, National Grid continues to be committed to reducing the amount of solid waste generated, as well as its consumption of fuel, paper, and other resources.

Minimization and proper management of waste generated and reuse or recycling of waste materials is one of many principles defined in the Company's environmental policy.

Waste minimization policies are communicated to National Grid staff through training materials, videos and informational and educational articles. Internal audits of environmental practices at National Grid facilities also ensure adherence to Company policy and procedures.

Set forth below is a chart showing generation of waste and recycling over a several year period.

| | FY05 | FY06 | FY07 |
|---|---|---|---|
| **Solid Waste (tons)** | 5450 | 5610 | 5627 |
| **Hazardous Waste (tons)** | 324 | 354 | 475 |
| **Recycled Waste (tons)** | 12,262 | 11,301 | 10,317 |

### Hazardous Waste

National Grid generates hazardous and non-hazardous wastes as a routine part of its operations. Among the sources of such wastes are the retirement of PCB-containing electrical equipment, utility poles and streetlights, as well as the cleaning of manholes and vaults of accumulated water and sediments.

The Company has established environmental procedures and guidance documents to ensure that all wastes are managed in accordance with regulatory requirements and Company policy. In Fiscal Year 2007, National Grid generated 950,000 pounds of EPA-regulated hazardous waste. (Note: This does not include waste generated as part of of our Site Investigation and Remediation Program). While the Company encourages the recycling of waste whenever possible, some wastes may be put in landfills or incinerated.

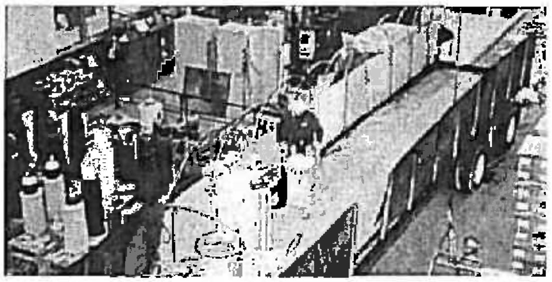
No wastes are shipped directly across international borders from National Grid; however, some wastes are ultimately shipped across international borders for final disposal by a vendor after consolidation at a licensed vendor Transportation Storage and Disposal Facility. In Fiscal Year 2007, 3,900 pounds (1,771 Kg) of lead acid battery waste were shipped across international borders on five occasions for recycling. This value represents 0.2 percent of the federally-regulated hazardous wastes generated by National Grid.

### Investment Recovery and Recycling

Recycling plays an important role in the Company's efforts to minimize waste and use resources more efficiently. National Grid's Investment Recovery and Recycling Services Center recycled a total of 9,803 tons of materials in Fiscal Year 2007. The facility is the centerpiece of a corporate effort to minimize National Grid's waste generation and reduce costs by seeking solutions to environmental issues such as solid waste.

The Investment Recovery facility has been in operation for two decades. The facility includes a core marketing staff that locates buyers and a team of workers that operates the equipment. The marketing staff of three people searches for opportunities within the Company to locate surplus, obsolete, resalable materials, which could be new or used, and are no longer needed by the Company. These materials are sold globally through a variety of programs. A support staff of 12 people performs a number of tasks at the site to ready the materials for sale.

Located in Syracuse, New York, the facility is ISO 14001 certified and processes a variety of materials from the Company's transmission and distribution operations, substations, corporate offices and vehicle fleet. National Grid's Investment Recovery Center provides not only environmental and social benefits to the community, but it also provides significant financial benefits to the Company. Savings and income from sold material represented approximately $11 million in Fiscal Year 2007.



*National Grid's Investment Recovery and Recycling Services Center provides environmental and social benefits to the community, as well as financial benefits to National Grid.*

The center handles three primary categories of materials:
***Scraps/recyclables*** – Non-ferrous metals, ferrous metals, processed metals, processed wire and cable, wood products, cardboard, paper, plastics and porcelain.
***Office equipment*** – Computers, furniture, excess supplies, toner cartridges, telecommunications equipment and lighting.
***Electrical equipment (for sale, decommissioning or reuse)*** – Generator parts, refurbished hardware, distribution equipment, substation equipment, transmission equipment, transformers, cable and conduit hardware meters, switches and relays.

Among the center's services are the sale of excess inventory and obsolete material; the sale of stock materials to other utilities; and safe, environmentally sound disposal of unusable materials.

**Helping the Disabled: An Environmental Success Story**
At National Grid's Investment Recovery Center, a group of 35 to 40 mentally and physically disabled people are given the chance to experience a normal working life and are paid for their efforts. They work and are trained in the Investment Recovery warehouse, which leaves them able, in time, to move to similar jobs elsewhere.

These workers are given a range of tasks, such as streetlight dismantling and segregation of metals and packaging material. This operation will expand into the new National Grid Northeast Distribution Center in Sutton, Massachusetts in the fall of 2007.

## ◆ Environmental Compliance

**Underground Storage Tank Removal Program**

National Grid's compliance with environmental rules and regulations includes programs to mitigate possible pollution sources. For example, the Company has historically stored a number of petroleum products in underground storage tanks (USTs), including gasoline and diesel fuel for motor vehicles, diesel fuel for emergency generators, motor oil for fleet garages and used oils from maintenance operations.

In 2004, National Grid undertook a study to evaluate the risk and cost of operating underground petroleum storage tanks, focusing primarily on vehicle fuel tanks. The study took into consideration the age and design of the tanks, potential environmental impacts that could be caused by tank leakage, costs of operating USTs and benefits of maintaining on-site fuel storage.

As a result of the study, it was decided that maintaining underground petroleum storage in many cases posed an unduly high environmental risk and operating cost. In 2005, National Grid decided to remove all underground petroleum tanks; the tanks were replaced by above-ground tanks on a need basis only, primarily for operation of emergency diesel generators. The Company opted to go to off-site vendors for its fuel needs. A total of 92 underground storage tanks were removed in New York and New England. In addition, six above ground storage tanks (ASTs) were removed that were considered unnecessary or too expensive to upgrade; seven ASTs were upgraded; and 46 ASTs were installed as replacements for USTs. The program is now complete and no USTs remain in National Grid's current system.

**New SPCC Regulations**

To comply with Spill Prevention, Control and Countermeasure (SPCC) requirements, National Grid has developed SPCC plans for its electric substations and service centers. As part of the implementation of these plans, secondary containment or spill diversion structures have either been installed or are in various stages of planning or construction.

In December 2006, in response to utility and industry comments, the US EPA amended the SPCC rule to allow for strong contingency planning as an alternative to the installation of secondary containment for oil-filled equipment. In related rulemaking, EPA also extended the SPCC compliance deadline to July 1, 2009.

National Grid reviewed the new SPCC regulations and plans to adopt the contingency planning option for demonstrating SPCC compliance at its electric substations. This is a significant change in policy but will save more than $11 million over the next three years by eliminating the need to install new containment structures at minimal increased environmental risk. However, it will be important to maintain a good inspection program and to promptly respond to alarms and spills with adequate resources.

Despite our ability to comply with EPA regulations using contingency planning, National Grid recognizes that some installations and water receptors are more sensitive than others. Therefore, on a case-by-case basis, secondary containment may be environmentally prudent and will still be installed. For example, installation of containment would be strongly considered where equipment is close to a drinking water or recreational water supply.

**Environmental Audit Program**

The goal of National Grid's Environmental Audit Program is to provide independent verification and assurance to management that the Company's operations are performed in accordance with applicable environmental statutes and regulations and conform to internal environmental policies and procedures, as well as to determine if environmental management systems are in place to ensure continued conformance.

During Fiscal Year 2007, risk-based audits focused on various company sites and assets, such as service centers, substations and transmission line rights-of-way. The Environmental Audit Program included three management system audits and 18 compliance audits, covering company operations at 102 facilities, substations, and projects. As a result of such audits, 103 nonconformances were identified and promptly resolved by the company.

The process used for the audits was consistent with state-of-the-art environmental auditing protocols. Environmental issues as follows were reviewed in Fiscal Year 2007:

- air pollution control;
- asbestos management;
- Comprehensive Environmental Response, Compensation, and Liability Act/ Emergency Planning and Community Right-to-Know Act (CERCLA / EPCRA);
- drinking water management;
- hazardous materials transportation;
- PCB management;
- solid and hazardous waste management;
- spill prevention and control;
- underground injection control;
- underground storage tanks; and
- water pollution control.

Exceptions to either external regulatory requirements or internal company procedures are noted within each report issued through the Environmental Audit Program. The audit team also presents management with recommendations to resolve each exception noted. These recommendations are made not only to generate corrective action, but also to request that management provide a resolution to prevent recurrence of these exceptions.

For significant exceptions, which may have an impact beyond the operating area where the exception was initially noted, the request for preventive action may expand to cover all operating areas where similar issues may occur. By requesting comprehensive resolutions from management, which include both corrective and preventive measures, the Environmental Audit Program is used to strengthen National Grid's compliance program efforts.

As a final measure, the Environmental Audit Program requires tracking of all resolutions to ensure that each has been fully implemented. Documentation or other physical evidence is provided to the audit team to demonstrate completion of corrective and/or preventive actions, and follow-up site visits are scheduled, as necessary, to ensure improvements to the compliance program have been made.

### Vendor Auditing

National Grid's environmental vendor audit program was established in order to provide structure to the auditing of waste disposal and recycling vendors. The scope of the vendor audit program includes hazardous waste/PCB disposal facilities, recycling facilities and scrap metal facilities. On a select basis, solid waste landfills or other types of facilities may be reviewed depending on the circumstances.

The National Grid Vendor Advisory Group (VAG) meets quarterly to discuss vendor audit activity. Membership of the VAG includes representatives from Legal, Environmental, Procurement, Operations and Investment Recovery. The VAG establishes an annual audit schedule for auditing and reviewing selected vendors. In Fiscal Year 2007, a total of eleven (11) on-site vendor compliance audits were conducted.

### Environmental Training

It is National Grid's policy to support compliance objectives by promoting employee environmental awareness through frequent and comprehensive training programs.

Employees involved in activities that could have a significant environmental impact – including hazardous waste management and spill response – receive training specific to their job responsibilities and in accordance with federal, state and local requirements.

This may be accomplished in several ways such as classroom training, video refresher training or computer-based training. Employees are made aware of the National Grid Environmental Policy, the requirements of the Company's Environmental Management System, environmental procedures, and environmental guidance documents, as well as operating procedures and applicable regulatory requirements. National Grid's training program helps each employee safely perform his or her duties when handling hazardous waste, oil and other hazardous materials.

### Environmental Compliance Data

National Grid is committed to maintaining compliance with all applicable environmental laws, rules and regulations, and, when possible, exceeding them. When we become aware of potential non-compliance, we move swiftly to address and remedy the situation.

*Set forth below is compliance data for Fiscal Year 2007:*

### Environmental Inspections

From time to time, federal and/or state officials inspect our facilities. During Fiscal Year 2007, regulatory agencies performed a total of 22 inspections at National Grid facilities in the US.

### Notices of Violation

In Fiscal Year 2007, National Grid received eight notices of alleged violations related to its US operations, down from 9 and 14 notices in the prior two fiscal years, respectively. Since receipt of these notices, we have taken corrective action to resolve the noted deficiencies to the satisfaction of the regulatory agencies.

*Summary of Notices:*

- Failure to submit Biennial Hazardous Waste Report
- Enforcement Order for damage to wetland resource area.
- Error in manifesting and hazardous waste shipment.
- Unauthorized solid waste dumping on company right of way.
- Unauthorized dumping on vacant company property.
- Failure to follow up on and notify of a threat of a release of oil.
- Failure to submit Phase III, IV and RAO within specified timeframe.
- Unauthorized cutting and injuring of trees on state land.

### Penalties

In Fiscal Year 2007, National Grid received financial penalties associated with regulatory noncompliance on two occasions. In September 2006 National Grid paid a penalty of $2,925 for a hazardous waste manifest error. In March 2007, National Grid paid a penalty of $1,960 for unpermitted tree cutting in the Winona State Forest.

### Releases/Spills

National Grid's operations may result in spills of oil and/or hazardous materials. These may include non-PCB oil, PCB-contaminated oil, PCB oil, diesel fuel, hydraulic fluid, antifreeze, mercury and refrigerant. Causes of spills may be under our control, such as equipment failure, or beyond our control such as damage from severe weather or third-party motor vehicle accidents. National Grid responds to all spills and ensures each is properly addressed. Also, the Company categorizes each spill, with the most significant spills being assigned a Category 1 classification. In Fiscal Year 2007, National Grid experienced 30 Category 1 spills and 977 Category 2 spills. The Category 1 spills are listed below.

| | |
|---|---|
| **May 2006** | Discovery of PCB-contaminated soil at school in RI |
| **May 2006** | Receipt of a legal notice from a Conservation Commission for damage to a wetlands by a National Grid vendor |
| **May 9, 2006** | 26 gallons non-PCB oil |
| **May 14, 2006** | 500 gallons non-PCB oil |
| **May 16, 2006** | 10 gallons non-PCB oil |
| **May 19, 2006** | 26 gallons non-PCB oil |
| **May 25, 2006** | Release of bentonite by a vendor to a stream |
| **May 30, 2006** | 7 gallons non-PCB oil |
| **May 31, 2006** | 16 gallons non-PCB oil |
| **June 2006** | 120 gallons non-PCB oil |
| **June 1, 2006** | 11 gallons non-PCB oil |
| **June 7, 2006** | 7 gallons non-PCB oil |
| **June 7, 2006** | 5 gallons non-PCB oil |
| **June 14, 2006** | 100 gallons non-PCB oil |
| **June 16, 2006** | Violation by a vendor transporting our wastes |
| **June 30, 2006** | 5 gallons non-PCB oil |
| **July 17, 2006** | Unknown quantity of non-PCB oil |
| **July 19, 2006** | 5 gallons non-PCB oil |
| **July 31, 2006** | 135 gallons non-PCB oil |
| **August 3, 2006** | 225 gallons non-PCB oil |
| **August 25, 2006** | Unknown quantity of non-PCB oil |
| **August 29, 2006** | 25 gallons non-PCB oil |
| **September 3, 2006** | 25 gallons non-PCB oil |
| **September 8, 2006** | 2 gallons non-PCB oil |
| **October 14, 2006** | 4 gallons PCB-contaminated oil |
| **October 17, 2006** | 7 gallons non-PCB oil |
| **October 28, 2006** | 7 gallons non-PCB oil |
| **October 30, 2006** | 103 gallons non-PCB oil |
| **November 16, 2006** | 150 gallons non-PCB oil |
| **January 2, 2007** | 20 gallons non-PCB oil |

Approximately 1,541 gallons of oil were released by the 25 Category 1 oil spills for which a spill quantity is known. In general, most of these spills were able to be completely remediated immediately after the spill event and had no lasting impact. Only one spill in Fiscal Year 2007 was required to be reported in our financial statement. In that incident, PCB-contaminated soil was discovered when responding to a release of non-PCB oil from a pad mounted transformer at the Hugh Cole School in Warren, Rhode Island. The PCB contamination appeared to be the result of a release from a PCB transformer that had previously been located there. The PCB-contaminated soil was cleaned up without incident.

### Environmental Oversight Committee

The compliance activities of the Company are closely tracked by the National Grid Environmental Oversight Committee. The Committee reviews all legal notices received from federal, state or local regulatory agencies, reviews all corrective actions, and sets strategic direction in ways to maintain the "state of the art" status of the Company's environmental management system.

### The October Surprise

National Grid's concern for the environment extends to its reliability commitment, particularly in reporting storm damage. For example, unprecedented meteorological conditions on October 12 – 13, 2006 in the western New York area created a heavy, wet snowfall that resulted in widespread vegetation damage and associated power outages. Dubbed the "October Surprise" by the media, the storm left approximately 265,000 National Grid customers without power. As a result of the storm, 220 pole-top transformers were damaged and removed from service. Much of the damage was due to falling trees and branches, which caused transformers to fall from utility poles or primary and secondary wire to break, causing broken bushings.

Approximately half of the damaged transformers created oil spills that were reported to the New York State Department of Environmental Conservation (NYSDEC). Some of these spills were also reported to the National Response Center, because the oil spill traveled to waterways or stormwater sewers. A dozen additional oil spills associated with vehicle fluid spills also were reported, thus making 87 storm-related oil spills.

*The October 2006 storm in western New York brought down thousands of leaf-covered limbs, branches and trees, along with hundreds of miles of electrical distribution and transmission lines.*

National Grid and its spill response contractors responded to the oil spills using a phased approach. Considering the importance of safety to the public and National Grid crews, the primary focus was to first identify and report the oil spills, followed by oil containment and placement of visual barricades to isolate the areas. After the affected areas were made safe and electrical infrastructure was restored, cleanup and required sampling were completed.

Despite the often adverse conditions, such as heavy rains in the weeks following the October Storm, oil spill cleanup and site restoration were completed to the satisfaction of the NYSDEC and impacted customers.

On October 17, 2007, National Grid announced that it is supporting the broad effort to mitigate the devastating impact of the October 2006 snowstorm on Western New York's trees through grants and special program allocations totaling $175,000. National Grid will partner with Re-Tree WNY, the volunteer organization formed shortly after the storm with a goal of planting 30,000 trees throughout the affected region over the next five years. The National Grid donations include economic and charitable grants, along with an extension of an existing company program that will support municipal efforts to re-forest public rights of way.

## ◆ Site Investigation and Remediation Program

A major part of National Grid's environmental program is dedicated to investigating and cleaning up former manufactured gas plants (MGPs) and other sites impacted by historical industrial operations. The Company has invested a significant effort to address these sites, which has yielded impressive results benefiting the communities in which National Grid operates. Investigation and remediation of MGPs are a good example of how we have addressed past contamination. Beginning in the mid 1800s, manufactured gas became a common source of fuel in Massachusetts, Rhode Island and New York. MGPs converted coal and/or oil into gas that was piped into homes and businesses, where it was used for lighting, cooking and heating. In addition to creating gas, MGPs created by-products such as tar and emulsions. Virtually all MGPs were closed by the early 1960s. National Grid is working to remediate residuals from former MGP sites according to state and federal regulations under the direction of the US Environmental Protection Agency, Massachusetts Department of Environmental Protection, New York State Department of Environmental Conservation, and Rhode Island Department of Environmental Management. National Grid has a well established Site Investigation and Remediation (SIR) program in both New York and New England facilitating investigation and remediation activities.

**Fiscal Year 2007 Accomplishments in Site Remediation**

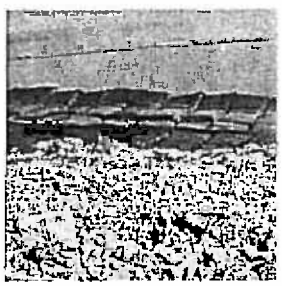
In Fiscal Year 2007, National Grid US was a potentially responsible party under Superfund laws for the remediation of over 180 contaminated sites in New England and New York and for resulting damages. The National Grid SIR program completed seven environmental investigations, selected remedial strategies for three sites, completed seven remedial designs and remediations and completed work at four sites. The Company continues to aggressively pursue cost-effective remediation strategies through careful engineering and science-based solutions. One important accomplishment includes significant progress on sediment toxicity programs. The mission of the sediment program is to focus remediation only on areas that pose a real risk to human health and the environment. National Grid took the leadership role in developing the Sediment Contaminant Bioavailability Alliance (SCBA), a group of industries that work together to understand sediment bioavailability and toxicity. The scientific validity of the sediment toxicity program was enhanced as additional samples were collected from National Grid and SCBA member sites and analyzed. Results are showing samples with low chemical measurements as non-toxic and others with high chemical measurements as toxic, with chemical measurements between these two groups showing uncertain toxicity. National Grid has funded a study to understand and reduce the uncertainty associated with this group of samples. The EPA, in an effort to incorporate the latest information on sediment bioavailability, issued a notice in the Federal Register in the spring of 2007 requesting comments on the agency's current understanding of sediment toxicity. National Grid, through SCBA, provided detailed comments to the EPA outlining our sediment bioavailability program.

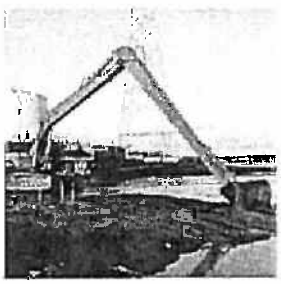
During the winter of FY07, National Grid completed sediment remediation projects at former MGPs in Salem and Danvers on the North Shore of Massachusetts. The projects represented the final stage of multi-year investigation and remediation efforts. The land portion of the former MGPs was relatively straightforward to investigate; however, the approach to investigation and remediation in the aquatic environment was a more challenging undertaking, due to the inherent complexities of investigating, permitting, and conducting work in marine environments. Set forth below is a summary of these two sites, as well as the Amsterdam, New York site.

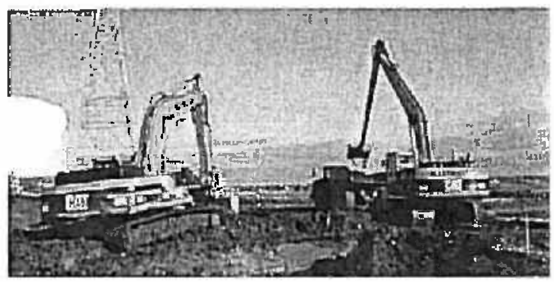
**Salem MGP, Salem, MA**

The Salem MGP was the largest on the North Shore of Massachusetts and operated between 1890 and the early 1950s when natural gas was introduced to the area. Since the cessation of the MGP operations, this approximately 36 acre site has been used for the storage and distribution of natural gas and the transmission of electricity. The remediation strategy involved a staged approach that was developed to protect human health and the environment while not impeding the facility's operations.

The first stage in the remediation involved cutting off contaminants that migrated to the adjacent Collins Cove. This was accomplished by installing two subsurface barrier walls on the site in 1998. One of the walls allows the passage of groundwater through treatment structures, which remediate the groundwater as it flows to the cove. Subsequent remediation activities included the installation of a new storm water drainage system followed by the capping of a portion of the terrestrial side of the site.







*Marine armor mattresses and rip rap armor were placed on the coastal beach, and coal-tar contaminated sediments were excavated from the intertidal zone of Collins Cove at low tide.*

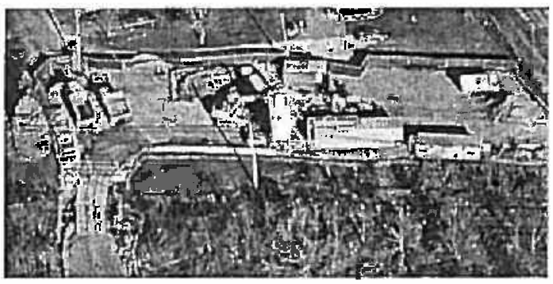
The final stage of the site remediation involved the excavation and off-site disposal of over 7,000 cubic yards of coal tar-contaminated sediments from the intertidal zone in Collins Cove and the restoration of the tidal flats from which the sediments were excavated. The removal and back filling of the sediments was accomplished "in the dry," conducting the work around the tidal cycle when the flats were exposed. The excavation and backfilling of 7,000 cubic yards of sediment in an area of approximately 70,000 square feet was completed in seven weeks.

In addition to the sediment remediation, approximately 1,000 linear feet of coastal beach was capped with riprap and marine armor mattresses. Previously, the coastal beach consisted of a surface layer of miscellaneous MGP building rubble and hardened coal tar. By capping the beach, the migration of this material to other parts of Collins Cove is being prevented. The project was completed in April 2007.

**Danvers MGP, Danvers, MA**

The Danvers MGP, which operated between 1861 and 1906, was a smaller MGP operation than the one in Salem; it encompassed approximately one-third acre on the shore of the Crane River. The former MGP operations existed on two parcels of land. One was a vacant open space and the other was a residence that was constructed on the property after the MGP operations had ceased. The dense residential setting near the MGP presented additional challenges.

The upland remediation was conducted in two phases: the first phase involved the excavation and disposal of approximately 1,400 cubic yards of contaminated soil from the vacant parcel in 1998. For the second phase, National Grid purchased the property and removed the house in order to conduct the investigation and remediation. During the winter of 2005/06, the excavation and removal of approximately 1,600 cubic yards of contaminated soil was conducted. The area was backfilled with clean soil and loam, then seeded, and restored to a grassy open space.



The dredging of the coal tar-contaminated sediments in the Crane River was conducted during the late fall and winter of 2006. As was done for the Salem dredge project, the work was conducted around the tidal cycle in the dry. However, access to the flats was a challenge, as the river is situated approximately 15 feet below the upland portion of the site. A total of approximately 2,500 cubic yards of sediment was mechanically dredged using a temporary earthen ramp access road, constructed on the river bank and a timber mat temporary working road. The dredged material was mixed onsite with cement powder for drying and stabilization, and transported off-site for thermal treatment. The dredge areas were backfilled with clean sand and the disturbed wetland areas were restored. The project was completed in December 2006.

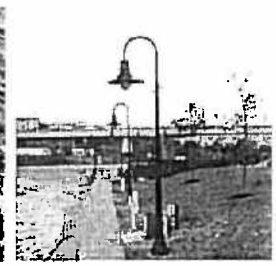
*The residential setting presented unique challenges to the project, but the sediment excavated from the tidal river was successfully processed on the upland portion of the site and transported out of the neighborhood to a recycling plant.*

### Amsterdam (Front Street) Former MGP Site

Waterfront property in Amsterdam, New York that was the site of a former MGP is now being developed into a large recreational park. This desirable property is on a portion of the Mohawk River between Locks 10 and 11 of the New York State Canal System. Lush green grass, new gravel driveway, chain-link fencing, and armor along the riverbank are now situated on the waterfront property. Work to remediate the site and turn it into parkland was completed on schedule in October 2006, despite massive river flooding that occurred in June 2006. National Grid began the cleanup, in cooperation with the New York State Department of Environmental Conservation, in March 2006.

The former MGP originally consisted of three gas holders, which had long since been taken down when work began on the cleanup. MGP contaminants from the production of gas and former storage tanks had seeped into the soil and the water at the site. National Grid's remediation of the site included installing permanent sheetpiling up to 70 feet below ground surface around the perimeter of the site, permanently encapsulating and sealing contaminated soils beneath the site, and installing an engineered cover to vent gas and drain groundwater. Clean soils were used to cover the site, and groundwater monitoring and collection wells were installed inside the sheetpiling to collect contaminants.

*What was once a restricted area of contaminated soil from a former MGP is now a rolling two acre waterfront property that will become Phase II of the Amsterdam Riverlink Park.*



The addition of the recreational area to the city's waterfront has added approximately 2 acres of public green space for the City of Amsterdam to develop and residents to enjoy.

## ◆ Environmental Stewardship

### Overview

National Grid recognizes the threats its work can pose to biodiversity and has developed programs and procedures to manage them. Threats include habitat fragmentation, destruction and alteration, and invasion by alien or invasive species. In planning and constructing new facilities and rights-of-way, the Company consults with federal and state natural resource protection agencies to identify and protect sensitive habitats. In some cases, project permits with these regulatory agencies include specific conditions to address or control invasive species.

Moreover, National Grid's environmental procedures and guidance for natural resource protection include the use of project planning and permitting checklists, along with right-of-way access, maintenance and construction best management practices. These environmental procedures and guidance are intended to avoid or minimize overall environmental impacts, including the major threats to biodiversity. By implementing appropriate design, work site selection, scheduling, and practices to avoid or minimize disturbances to sensitive habitats, National Grid helps to conserve biodiversity.

### Wetlands

National Grid's transmission and distribution lines travel through wetlands within New York, Massachusetts, Rhode Island, New Hampshire and Vermont. We recognize a responsibility to help protect these areas and the wildlife that lives within them. To ensure that our operations do not have an adverse impact on wetland resource areas, our Environmental Department provides wetland protection training to operations and engineering personnel.

National Grid is also a participating member in the Corporate Wetlands Restoration Partnership (CWRP), a group aiming to preserve, restore, enhance and protect aquatic habitats throughout the US. National Grid and other corporate partners continue to contribute money and in-kind services to CWRP. This partnership, established in 1999, was one of the first programs in the nation to enable corporations to combine talent and resources for the protection, enhancement and restoration of wetlands and other aquatic habitats. Facilitated by the Coastal America Partnership in Washington, DC, the CWRP enables member corporations to donate funds, which are matched with federal and state funds to undertake restoration projects.

More than 300 corporate partners have contributed time and money to facilitate selected projects. Since its inception in 1999, CWRP has aided in the restoration of more that 20,000 acres and 7,000 stream miles through the monetary donations and in-kind services of its corporate partners.

**Endangered Species**

Some parts of National Grid's service territory provide habitats for wildlife species that federal and/or state regulatory agencies consider to be endangered, threatened or species of special concern. Such wildlife includes listed species of amphibians, reptiles, birds, mammals, insects, mollusks and plants.

As an example, in New York, National Grid operates in some counties that have been identified by the US Department of the Interior as having occurrences of five endangered species: the Indiana bat (Myotis sodalis), Karner Blue butterfly (Lycaeides Melissa samuelis), piping plover (Charadrius melodus), shortnose sturgeon (Acipenser brevlorstrum) and clubshell (Pleurobema clava).

Federally listed threatened species include the bald eagle (Haliaeetus leucocephalus), bog turtle (Clemmys muhlenbergii), Chittenango ovate amber snail (Novisuccinea chittenangoensis), Houghton's goldenrod (Solidago houghtonii), American hart's-tongue fern (Aslenium scolopendrium var. americana), Eastern prarie fringed orchid (Platanthera leucophea), and Small whorled pogonia (Isotria medeoloides).

In New York, activities on National Grid rights-of-way (ROWs) have the potential to affect or be affected by two species listed as endangered by both the New York State Department of Environmental Conservation (NYSDEC) and United States Fish and Wildlife Service (USFWS) – the Indiana bat and the Karner Blue butterfly. The former appear to be concentrated in certain areas of our Northern, Central, Northeast, and Capital Regions, but are generally part of our assessments statewide in instances where removal of mature timber is required. The latter is generally found in the vicinity of Albany – Glens Falls on actively managed habitats associated with sandy soils (Glacial Lake Albany) that can support wild blue lupine and populations of Karner Blue butterflies. The unique habitat requirements of the Karner Blue species (oak savanna with extensive patches of wild lupine) are common on ROWs in this region, but historically could be associated with old lake dunes near Watertown, Rome, and Tonawanda – areas where there is agency interest in reestablishing displaced populations of both the plant and the butterfly.

*The Karner Blue butterfly, an endangered species, can be found on rights-of-way in the Albany area.*

National Grid is working with the USFWS and the NYSDEC to develop a Habitat Conservation Plan and Incidental Take Permit for the Karner Blue butterfly in New York. In 2006, a baseline survey of wild blue lupine, the sole larval food plant for the Karner Blue butterfly, was performed on various National Grid rights-of-way that provide potential habitat for this endangered insect species.

The Federal Endangered Species Act and associated state laws provide for the protection of many of these listed species and their habitats. In addition, state regulatory agencies provide some protections for other rare species of plants and animals, as well as for significant natural communities and habitats.

In planning and performing work, National Grid consults with federal and state agencies to identify the potential occurrences of such listed species and/or their habitats. The Company implements appropriate design, work site selection, scheduling, and practices to avoid or minimize disturbances to listed species and their habitats.

**Location of Habitats Of Species On National Conservation Lists**

National Grid has been extremely proactive in its species protection efforts on lands under its control. The Company employs two basic levels of species/habitat locational data routinely used in the United States. Both levels focus on rare, threatened or endangered species of plants and animals.

For federal natural resource-based permits (e.g., wetlands, storm water, hazardous waste, etc.), the application process usually requires disclosure of whether any federally-protected species are likely to be impacted. To address this matter, the applicant must query, in writing, the applicable federal agency charged with species protection. This includes the US Fish and Wildlife Service and the National Marine Fisheries Service. Results of their review, relative to "critical habitat" for protected species, may indicate no likely impact, thereby granting clearance to the activity being proposed or, conversely, a potential impact finding, resulting in the applicant's need to conduct scientific studies to ascertain possible project impact and proposed mitigation.

At the state-level, rare species protections are even more stringent because the criteria for listing are based on state-specific abundance and distribution, not national parameters. However, all state lists contain the species on the national list that have been recorded within the state jurisdiction.

For example, in Massachusetts, the Natural Heritage and Endangered Species Program has mapped rare species habitat statewide. Any organization proposing activity in those mapped habitats must file an application. The results are similar to the federal program, either no impact and the project proceeds as proposed, or applicant studies are needed to assess potential impact and appropriate mitigation.

**Osprey Nesting Platforms**

National Grid first erected poles for osprey nesting in Nantucket, Massachusetts in the 1970s. Osprey poles in Rhode Island were modified in the 1980s due to conflicts with nesting activity of ospreys. Many of the transmission and distribution structures that National Grid builds mimic dead trees, which are the preferred nesting sites of ospreys. Juvenile birds see these structures as excellent areas to build nests. The open space around the poles and location next to food sources are the reason for the nesting activity. We have erected dedicated poles for nesting, and modified existing structures to allow safe nesting in many areas. New designs of the structures are incorporating features to minimize fatalities to ospreys. The company works with wildlife representatives to mitigate conflicts with the ospreys.

In 1946, nesting sites numbered 143 in Rhode Island, this fell to 2 nests in 1967. Regulations restricting the use of DDT in effect since 1972 have been instrumental in the increase of the osprey population. National Grid has provided assistance in approximately 25% of the nesting sites located in Rhode Island. The number of nests has increased to 116 nests in the most recent survey in 2006. Ospreys were once on the endangered species list, but have been removed, and currently are a species of concern in Rhode Island, New Hampshire and New York.

**Guiding Principles for Siting Transmission Projects**

An example of National Grid's environmental stewardship is its Guiding Principles for Siting Transmission Projects which applies environmental sensitivities to the siting of transmission lines. The Company's Northeast Transmission organization believes that properly managing siting and licensing activities for transmission projects is vital to obtaining successful outcomes.

For such a project, a successful outcome is one in which:

- The transmission project is completed in a timely manner to address underlying reliability and/or economic needs;
- Transmission system technical and operational requirements are satisfied in a prudent manner, including those of National Grid and the applicable reliability organizations (e.g., ISO-New England and/or New York ISO, the Northeast Power Coordinating Council, the North American Electric Reliability Council, and the New York State Reliability Council);

- Environmental and permitting requirements are satisfied, as specified, at the federal, state and local level;
- The public, including abutters, state and local government officials, public interest groups and other interested parties, feels that its input has been considered and that the implemented project represents a good-faith effort to address concerns within the constraints of technical acceptability and overall cost to customers; and
- National Grid's reputation is maintained, and if possible, enhanced.

Pursuit of these objectives is in accordance with National Grid's Framework for Responsible Business.

The principles that follow apply to the licensing and siting activities for transmission projects in the Northeast, to guide the efforts of those engaged in these activities. In developing and presenting a proposed project, the Company will:

Act with integrity and honesty. Beyond the obvious requirements that we not deliberately make false or misleading statements, this means that we will:

- Provide relevant information in a timely manner;
- Keep the relative benefits of our preferred approaches, or the risks or negative characteristics of approaches we do not prefer, in proper perspective; and
- Only make promises that we are confident we will be able to keep.
- Treat all interested parties (stakeholders) with courtesy and respect.
- Consider stakeholder input on all phases of each project.
- Consider a range of reasonable solutions that are economical for consumers, technically feasible and within our ability to perform.
- Consider the human and environmental impacts, cost and technical merits of each alternative.
- Recognize that implementing effective public involvement processes can help to reduce the risks of delay.
- Recognize that timely, accurate, coordinated communications, both externally with Independent System Operators, Regional Transmission Organizations, regulators, government officials and the public, and internally among National Grid departments, is essential to success.
- Develop licensing and siting strategies early in the life-cycle of each project, and incorporate them at an appropriate level of detail in the strategy and sanction papers.
- Appropriately select the level of public outreach for each project and methods for public interaction on a project-by-project basis, reflecting the circumstances.
- Generally, we will pursue outreach approaches biased toward greater public interaction.
- Acquire all legally required permits and licenses prior to beginning construction.

National Grid's preferred approaches for dealing with the public, derived from the recommendations in *Dealing With an Angry Public*, by Lawrence Susskind and Parick Field (The Free Press, 1996), are to:

- Acknowledge the concerns of others.
- Encourage joint fact finding.
- Commit to working with affected constituencies to minimize or correct project-related impacts if they do occur.
- Accept responsibility; admit mistakes; and share power.
- Act in a trustworthy fashion at all times.
- Focus on building long-term relationships.

National Grid believes that by applying the Framework for Responsible Business, acting consistently with its Behavioral Values, and adhering to the principles stated above, it will maximize its ability to achieve successful outcomes for transmission projects.

## ◆ Environmental Awards

National Grid's environmental programs have earned numerous awards. In Fiscal Year 2007, these included:

***Tree Line USA.***
In April 2006, for the seventh year in a row, the National Arbor Day Foundation named National Grid a Tree Line USA utility for exemplary vegetation management. The distinction covers the Company's service areas in New England and New York. The Tree Line USA program, sponsored by the National Arbor Day Foundation in cooperation with the National Association of State Foresters, recognizes utilities that meet three requirements: a program of quality tree care, annual worker training in quality tree-care practices, and a tree planting and public education program.

***Narragansett Bay Commission*** (NBC)
Environmental Merit Award for Pollution Prevention.

In June 2006, NBC presented National Grid with an Environmental Merit Award for Pollution Prevention for efforts to reduce contaminant concentrations in vehicle wash effluent at the Providence facility. The award was presented at a Greater Providence Chamber of Commerce business meeting.

***Client of the Year Award.***
In June 2006, National Grid was named the 2006 Client of the Year by the Boston Chapter of the Society for Marketing Professional Services (SMPS). National Grid was selected because of its community outreach and support for the community during environmental remediation projects. The judges looked for a client that has a consistent, long-term commitment to excellence through the support of quality design and construction, contributes to communication and teamwork, and has demonstrated innovative ideas or practices that have positive results for the community. The Company was commended for its work in Massachusetts on the Perkins Park remediation (Newburyport), Arlington High School remediation and Vitale remediation (Beverly).

***Dunbarton, NH Right-of-Way (ROW) Erosion.***
In August 2006, National Grid received a letter from the Dunbarton, New Hampshire Conservation Commission that expressed appreciation for the Company's response to serious erosion issues that arose on National Grid rights of way in 2005. The water bars and culverts which National Grid repaired or installed are functioning properly and no further erosion issues have resulted.

***National Grid Receives Award for Use of Renewable Fuel for Fleet Vehicles.***
In September 2006, the AltWheels Alternative Transportation & Energy Festival and the Massachusetts Clean Cities Coalition announced that National Grid received an award as one of the four largest renewable-fuel users in Massachusetts. National Grid used 30,055 gallons of B20 diesel fuel in Massachusetts in 2006. The award was presented to Paul Zaremba, Manager of Fleet Asset Management, on September 22, 2006 during a public ceremony at Boston's City Hall Plaza. Boston Mayor Thomas M. Menino and State Senator Steven A. Baddour participated in the awards ceremony.

***Marblehead MGP Site Remediation Cited as a Success.***
In December 2006, the Massachusetts Department of Environmental Protection selected National Grid's remediation of the Marblehead former MGP site as one of ten projects to be included in their "Brownfield's Success Stories" brochure. The brochure contains a full page write-up of the project and photographs of the remediation and completed project. Remediation of the one acre Marblehead MGP site resulted in the creation of a seaside public park.

Over the years, National Grid has won the Environmental Merit Award for Pollution Prevention, Energy Efficiency Awards from the US Environmental Protection Agency, US Department of Energy, Edison Electric Institute and other organizations, as well as the US EPA Region 1 Environmental Merit Award and Rhode Island State Energy Office Certificate of Appreciation.

## Social Performance

## ◆ Overview

As with its service reliability and environmental performance, National Grid is committed to pursuing socially responsible policies and practices. The Company has programs and processes in place that are responsive to the needs of employees, customers, communities and other stakeholders.

To support this commitment, National Grid focuses attention on a range of employee evaluation, training and development activities, as well as programs aimed at promoting inclusion and diversity. Moreover, the Company has a well-documented health and safety program and initiatives to promote human rights, voluntarism and community involvement. What follows is a report on major elements of National Grid's social commitment.

## ◆ Our Employees

National Grid recognizes that it is through our employees that we will be successful. The Company is determined to provide financial and non-financial awards to make sure that all of its people share in that success. By investing in our employees, we are also investing in the future of our business.

Below is employment summary information for National Grid US in Fiscal Year 2007:

**Employee and Management Summary FY07**

| | |
|---|---|
| Regular Employees (full-time) | 8,270 |
| Regular Employees (part-time) | 175 |
| New England Employees | 3,921 |
| New York Employees | 4,524 |
| Employees Terminated | 200 |
| Employees Retiring | 423 |
| Union Employees | 5,268 |
| Percentage of Union Employees | 62% |

National Grid has a strong workforce consisting of both management and union employees, who are represented by a number of trade organizations in the United States. The representation is usually organized by employee group (i.e., industrial/staff) and structured at a local and national level. Collective bargaining units are in place to deal with working conditions (health and safety, remuneration, training) and employment conditions (hiring, promotion, downsizing). The Company currently has collective bargaining agreements with the Utility Workers Union of America, United Steel Workers, International Brotherhood of Electrical Workers and Brotherhood of Utility Workers.

The Company's focus is on strong communication and keeping employees aware of changes or new initiatives. While we practice face-to-face consultation, we also use our intranet, email and internal newsletters to publish information, answer questions and provide other supporting materials. National Grid also offers a strong internal training program for its employees, who are welcome to participate in their respective areas of expertise.

National Grid US provides the following retirement programs and other benefits:

- 401(k) savings plan with a monthly company match
- Defined benefit pension and insurance plans, including medical, dental and life
- Long-term disability
- Personalized total compensation profile which outlines an employee's total compensation package, including base salary, bonuses and benefits
- Flexible spending accounts allow employees to pay for out-of-pocket medical and dental expenses and dependent care with pre-tax dollars
- Vacation – all employees are provided with a range of vacation days depending on years of service with the Company

An important measure of success is through a two-way performance evaluation process between supervisors and employees. In Fiscal Year 2007 the percentage of performance reviews completed was not measured by the Company. During Fiscal Year 2008, the non-union population is being measured for the percentage of reviews – the goal is set at 100 percent.

## ◆ Aging Workforce

Based on workforce planning projections into the next five and 10-year periods, National Grid determined that one of the organization's greatest challenges will be maintaining a talented and educated field force. The Company made assessments of programs already under way across the country from which it might pull co-ops and employees to meet specific workforce needs. The biggest challenge in drawing from schools and institutions is that relocation is often made difficult by cost-of-living and weather factors that create hardships and reduce interest.

Through research undertaken at National Grid, it was determined that the greatest opportunities would be presented if:

- We worked to develop relationships with vocational/technical schools, tech prep consortiums, the Utilities Workers Union of America, the IBEW and Workforce Investment Boards to serve as supportive funnel groups for new workers;
- We developed a curriculum that would train men and women to pursue careers in the industry's field force;
- We included a National Grid-sponsored practicum that placed learning into a real industry setting;
- Careers and opportunities within the industry and National Grid were marketed to the public; and
- Schools and colleges were identified that included diverse, underrepresented populations and reflected the population that National Grid serves.

Therefore, to meet the variety of National Grid's field force career needs, the Company worked with three Massachusetts community colleges to develop a curriculum and a National Grid practicum that could be undertaken in a college-credit certificate program. National Grid applied with the three community colleges to secure a $1.9 million US Department of Labor grant to support the first three years of the program's development, implementation, faculty hiring, practicum and laboratory development. The grant provided the seed money to launch the program at all three institutions in September 2007. Additionally, National Grid hopes to replicate the model within its service territory in the years ahead and to share the lessons learned with utilities across the nation. Finally, National Grid received a Massachusetts Work Force grant for its Massachusetts community college program.

National Grid operations personnel have been working with key universities to ensure that National Grid is well positioned for college recruiting. Within the Engineering program at the colleges, there are two programs: four-year schools and two-year schools. Our New York business has focused its four-year effort on 11 universities across the franchise area, in particular working with five schools that have a power engineering focus.

For the two-year schools program, our New York business has identified eight community colleges that have an Electrical Engineering associate's degree program and is recruiting from them specifically for distribution design positions.

Both programs have an engineer from the Company assigned to work with the college Career Services and Engineering Departments to increase company recognition and recruiting opportunities.

For field technical degrees, New York Operations uses the model from National Grid's Western Division to modify an already existing electrical engineering curriculum at a two-year community college, adding a line worker training course, lab work and an internship as part of a Line Worker Certificate program. Erie Community College graduated its first class in the spring of 2007, and National Grid hired 12 graduates into its entry-level line worker position. Hudson Valley Community College began its first program in the fall of 2007. We are also working with Onondaga Community College to talk about a similar program.

*Judy Dunn( photo, left), vice president, Human Resources, seen here on the Syracuse University campus, is leading the search for good engineers from good colleges and universities.*

National Grid has also been selected to chair the National Education council for the Center for Energy Work Force Development (CEWD), a component of EEI. This positions National Grid prominently in the national discussion.

## ◆ Field Workforce Evaluation

Industry studies have indicated that an aging workforce will have a dramatic impact across the United States. In particular, much focus has been placed on the physical workforces of electric and gas utilities where training and development is a time consuming and costly process. In 2005, National Grid's Customer Operations department began evaluating the state of its field workforce and the effect of retirements over a five-year rolling window.

The evaluation identified a complex combination of issues taking place simultaneously. A projected increase in retirements was complicated by the fact that the Company had offered an early retirement package to its field workforce as part of consolidation driven by merger activity. The short-term solution was increased reliance on contracted staff. Although day-to-day operations seemed to be in control, the Company struggled with managing moderate storm and emergency events solely with its internal employees. Recruitment of individuals meeting minimal job skills criteria was complicated by the competing needs of neighboring utilities.

To address this problem, the Customer Operations group implemented a five-year staffing plan that supports key factors as follows:

- Maintaining internal staffing levels so that moderate storm and emergency events can be handled without outside assistance;
- Phasing in workers at various stages to support progression timeframes;
- Working to improve recruitment activity by targeting a portion of new hires as individuals rated to perform certain work;
- Working with local vocational and community colleges on the development of training programs and expanding the candidate pool.

In addition, Customer Operations has focused on reviewing progression time frames and training methods and setting the proper level of performance expectations for its field workers.

## ◆ Safety & Health

At National Grid, safety is not just a priority, but also a value that guides our actions. We recognize that each of us has a personal responsibility for our own safety and the safety of those around us. Our objective is to achieve zero injuries. While this objective is demanding, we believe it is achievable.

To help reach our zero-injuries target, we have established a Safety and Occupational Health Policy with the following principles:

- Meet, and where appropriate, exceed the requirements of health and safety legislation, policies, and other commitments to which we subscribe;
- Ensure our assets are designed, constructed, operated and maintained to standards that promote good safety performance through the life of the asset and when decommissioned;
- Require our contractors to demonstrate the same level of commitment to good safety and occupational health performance;
- Actively involve employees in improving safety performance and ensure that they have the skills, knowledge and resources necessary to maintain a healthy and safe working environment;
- Identify hazards and unsafe behaviors and manage risks associated with our activities and deliver any improvements through an effective health and safety management system and clear performance standards;
- Analyze incidents that result in, or could have resulted in, injuries, illnesses or asset damage to identify the causes, avoid recurrence and share the lessons with the appropriate people.

The complete Safety and Occupation Health Policy and our Vision Statement may be viewed at www.nationalgridus.com.

**Safety and Health Management**

National Grid believes that everyone in the organization is responsible for good safety and health performance. To help support and guide the organization, there are 50 safety and health professionals within the Safety, Health and Environment group. The safety and health team also helps to ensure that management systems are in place to adequately control risks and facilitate continuous improvements. Below is a summary of key areas of support:

*Incident Prevention and Management*

- Develop and implement programs for the prevention of incidents that may result in or have the potential to result in injuries to employees and contractors.
- Identify injury and other incident trends and continually communicate performance to raise awareness.
- Analyze, report, and learn from incidents, including near misses, as well as injuries.

*Medical and Health Services*

- Provide for management of work-related and non work-related injuries and illnesses including early medical intervention and treatment.
- Provide medical services that ensure accurate evaluation of employee capabilities, return to work programs, control of absenteeism and substance abuse testing.

*Contractor Management*

- Support the Contracted Services Program that addresses contractor health and safety work plans, risk assessment, job briefs, and incident reporting and analysis.
- Set the same expectations as for our direct workforce.

*Safety Culture & Leadership*

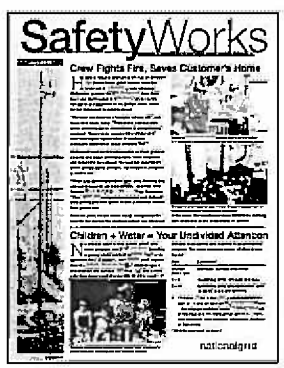
- Promote safety behaviors through leadership, training, and safety observation tours.

*Training*

- Develop and deliver employee training programs and orientation that meets regulatory and enhanced performance requirements.
- Provide training that addresses technical skills and qualifications, regulatory and company procedures, work practices, safety and health leadership.

*Regulatory Compliance*

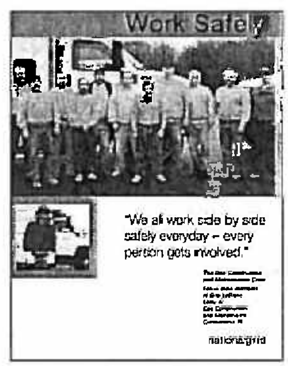
- Develop and implement safety and health policies, procedures and work practices to ensure compliance with governmental regulation and industry best practices.
- Create strategies to address emerging issues important to the business.
- Interact with regulatory agencies (Occupational Safety and Health Administration, Department of Transportation, etc.) during inspections and during the development of new regulations to ensure maximum business benefit.
- Manage occupational injuries/illness notification, reporting, recordkeeping as required by OSHA and state-level workers compensation regulations.



SafetyWorks

Crew Fights Fire, Saves Customer's Home

Children + Water = Your Undivided Attention

nationalgrid




*National Grid continually reinforces the importance of safety for all.*

**Safety in the Workforce**

After experiencing improvements during the last several years, in Fiscal Year 2007 National Grid experienced an increase in employee injuries that required time away from work (lost time injuries or LTIs). The number of LTIs went from 68 as of March 31, 2006 to 91 as of March 31, 2007, representing an increase of 32 percent. As a consequence, our lost time injury frequency rate rose from 0.86 in Fiscal Year 2006 to 1.17 in Fiscal Year 2007. According to the US Bureau of Labor Statistics, the average Lost Workday Case Rate for utilities in the US is 1.4. (Published 12/17/05)

Three of the most serious LTIs were directly related to the maintenance of the electrical system. On March 14, 2006 an employee was severely burned resulting in the loss of both arms when he contacted an energized overhead line; on December 15, 2006, an employee received burns on both hands when he was working to change a cutout; and on July 19, 2007 a trouble worker suffered burns to his face, arm and chest while changing a cutout.

## Safety Performance Summary

- Near-miss incident reporting target was met with a 50 percent increase over last year.
- The Injury-free day goal was not met. We ended with 294 injury free days and needed 306 injury free days to meet the target.
- Two new online systems to manage health and safety information were successfully implemented.
- The new Employee Safety Handbook based on the best practices in the organization was implemented.
- Annual Expert Training, conducted to ensure field workers maintain and refresh their technical skills, was enhanced to increase the safety components of training.
- The Safety Observation Tours (SOTs) target of observing 100 percent of applicable employees was nearly met, with 99.7 percent of the employees observed while conducting work activities. Additionally, the number of tours during second shifts, weekends and at the end of the normal work day were increased to ensure that a focus is kept on safety throughout the work day.
- In alliance with DuPont Safety Resources, a safety assessment was performed at the end of FY07 to evaluate safety improvement progress since the 2001 DuPont assessment, to identify performance-limiting gaps and to provide recommendations that will lead to improvements.
- Sixty percent of all injuries are related to soft tissue or muscular injuries. In Fiscal Year 2007 we began evaluating gaps in current soft tissue injury prevention programs, evaluating new programs and determining short-term and long-term improvement strategies to be implemented through the next two years.

As a result of these incidents, existing rules concerning insulating and isolating oneself from live energy, the minimum approach distances from live energy, and personal protective equipment were reinforced through employee retraining. These rules are also discussed during field safety observation tours and at safety meetings.

The number of LTIs also increased in our contracted workforce from 21 as of March 31, 2006 to 28 as of March 31, 2007.

Although the Company experienced a decline in performance with respect to injuries, we did experience some positive safety results:

- More than 40,000 Safety Observation Tours were conducted and 99.1 percent of them indicated that the workforce was performing work in accordance with prescribed work practices.
- The results of our employee survey indicated that a large majority of employees agree that the Company is committed to safety.
- Infrastructure improvements to support safety included:
  - Gas mains replacements
  - Leak surveys of all plastic and steel pipe
  - Indoor substation improvement projects- 95 percent completed since 2001
  - Potted porcelain cutouts – 150,000 have been replaced since 2002 with a target of 45,000 per year
  - Oil-Fused Cutouts – 10-year removal program began in 2003 and more than 2,200 removed to date (34 percent)

### Public Safety

Our employees are experts at delivering energy safely to the community, but everyone that lives and works around gas and electricity must be aware of the inherent dangers of live energy. In Fiscal Year 2007, six people died from contact with energized lines and equipment.

The National Grid DangerZone public safety outreach program was launched in 2005 and continued in 2006. The DangerZone is the minimum 10-foot clearance that must be observed around all overhead power lines. Most electrical contacts are indirect through ladders, scaffolding, vehicles, heavy machinery and other equipment. The DangerZone program consists of billboard advertising, customer bill inserts in multiple languages, videos, brochures and educational kits mailed directly to contractors and vocational schools throughout the US service territory. These materials communicate the dangers of direct and indirect contacts with overhead lines to contractors, construction crews, building trades students and homeowners. In addition to these materials, elementary schools within our service territory requested and received more than 375,000 student booklets and 4,200 safety videos designed to increase safety awareness among children.


*New to this year's DangerZone campaign, mobile billboards will cruise near construction sites and building supply stores.*

In 2006, National Grid also communicated public safety information about operating safely around underground utility facilities. In one year, our underground facilities were dug into over 600 times, inconveniencing customers and creating serious public hazards with potential for explosion, fire and electrocution.

### Safety Assessment

In alliance with DuPont Safety Resources, a safety assessment was performed at the end of Fiscal Year 2007 to evaluate safety improvement progress since DuPont's 2001 assessment. The purpose was to identify performance-limiting gaps and provide recommendations that will lead to improvements. Compared with the 2001 review, progress was shown in all of the "13 Essential Elements" of safety management with certain elements, such as Comprehensive Incident Analysis and Reports and High Standards of Performance, showing more progress than others. Strengths and weaknesses were identified and recommendations for improvements were provided. Priority recommendations include:

- Enable/require leadership to spend more time in the field.
- Improve the quality of Safety Observation Tours (SOTs) and follow-up on recommendations and findings.
- Develop a comprehensive, long-term staffing plan to ensure adequate resources.
- Train managers and supervisors in safety communications, conducting SOTs, and leading incident investigations.
- Cascade safety objectives and accountability to the supervisor level with greater line of sight between each work group and safety performance.

The assessment also showed that:

- The use and availability of required equipment and personal protective equipment has improved.
- Field workers are seeing evidence that reported safety issues are being addressed by management.
- Safety Observation Tours ensure that supervisory and managerial staff spend time in the field.
- The great majority of the workforce participates in Tuesday Morning Safety meetings and monthly safety meetings.
- Safety awareness has improved throughout the workforce.
- No evidence indicated that anyone condones short cuts to complete the job.
- People recognize they can impact the safety of others.

Actions to address the findings and recommendations are under way.

**Performance Objectives and Targets**

National Grid sets safety and health performance objectives and targets based on key risks. These targets are agreed to annually, although in some cases they are ongoing targets which will be delivered over several years.

For Fiscal Year 2007, the Company set employee goals in the categories of lost time injuries and near miss incident reporting.

In addition to these, targets were set for implementation of the safety initiatives. Results are summarized below:

**Lost time injury free goals (stretch target) according to lines of business**

| | |
|---|---|
| **Electric Distribution** | **Transmission** |
| 320 days | 365 days |
| **Gas Operations** | **Shared Services & IS** |
| 343 days | 362 days |

**Safety and Health Global Strategy**

In Fiscal Year 2007, representatives from National Grid's US and UK Safety, Health and Environment (SHE) organizations worked together to identify common issues and develop a global strategy for continuous improvement. Strategic areas to be developed include:

- Understanding Responsibilities – implementing "Golden Rules" for working safely and ensuring employees understand roles and responsibilities.
- Preparing to Work Responsibly – strengthening the risk assessment process.
- Measuring and Reporting – developing proactive performance measures.
- SHE Communications – providing more effective communication.
- Rewards and Recognition – developing new approaches to encourage the right behaviors.

In addition, we are pursuing the following improvement targets:

- Promotion of a positive safety culture by improving the leadership skills and knowledge of supervisors.
- Improvements in the quality of incident investigations by ensuring root causes and effective learning points are correctly identified and communicated, with all incident analysis reports and action items completed on time. The goal is 100 percent with a minimum threshold target of 90 percent.
- Reduction and prevention of soft tissue injuries through implementation of the soft tissue injury prevention plan.
- Reduce LTIs & LTI rate by: Target – 20 percent, Mid Target – 25 percent, Stretch Target – 30 percent.
- Achieve injury-free day goals according to the Lines of Business:
- Address DuPont/National Grid Safety Assessment recommendations including:
  - Enable/require leadership to spend more time in the field.
  - Improve quality of Safety Observation Tours and follow up on recommendations and findings.
  - Develop a comprehensive, long-term staffing plan to ensure adequate resources.
  - Train managers and supervisors in safety communications, conducting proactive Safety Observation Tours and leading incident investigations.
  - Cascade safety objectives and accountability to the supervisor level with greater line of sight between each work group and safety performance.

## ◆ Training and Development at National Grid

National Grid provides a range of training and development programs, including management, technical and expert training. The programs reflect the Company's commitment to develop our workforce and ensure that employees are trained in safety and other work-related issues.

Management training and professional development at National Grid provides training needs analysis and job task analysis to advise on and coordinate a variety of contracted management training courses.

In addition, the National Grid training group is also responsible for a number of in-house support functions to enhance leadership development. Leadership assessments; coaching and counseling for management employees including 360-degree feedback and peer and subordinate feedback reviews are part of what they do. Education reimbursement to employees taking college credit classes related to their position, along with career counseling to employees round out the support they provide to both management and represented employees.

**Technical Training at National Grid in Fiscal Year 2007**
National Grid operates two large training centers, one near Worcester, Mass. and the other near Syracuse, New York, both with a number of professional classrooms, completely fitted labs and outside training yards. Two smaller training centers, one in Albany, New York and one in Buffalo, New York serve those divisions with classrooms, labs and outside yards. Twenty seven training specialists are responsible for both electric and gas operations and construction training, some safety and emergency response training, meter training, system design training and operating systems training.

**Annual Expert Training**

National Grid employees receive technical, safety, mandated and procedure refresher training annually, as follows:

3 Days Gas Operations
2 Days Electric Operations (overhead and underground)
2 Days Electric Substations
2 Days Meter Services

- Each year, new employees to technical disciplines attend "Progression Training," or apprenticeship training, to build skills and knowledge while progressing within their new job. All field employees attend Annual Expert training during the year.

**Safety Training Annually**

Every operations employee received one formal day of safety training during Fiscal Year 2007 – CPR/First Aid or Safety Day (a variety of safety topics covered in one day).

**Weekly Safety Training**

Each operations employee in the field attends what is called the Tuesday Morning Safety Brief. The session usually lasts about one hour and is a combination of safety refresher training, incident and near-miss reviews, and discussion of various safety related issues. Supervisors lead the meeting.

**First Responder Training**

Gas and Electric Hazards training was conducted for emergency services workers, local officials, New York Public Service Commission officials and National Grid Operations management. The training was conducted at 13 locations across nine counties in upstate New York. More than 600 emergency services officials attended.

Technical Training also has learning initiatives underway. In Fiscal Year 2007 a class designed to expose employees to a broad understanding of the electric and gas distribution business was developed and delivered. The class was conducted in Syracuse one day each week over 20 weeks and broadcast to Albany, Buffalo and Westborough, Massachusetts, significantly saving travel time.

## ◆ Inclusion and Diversity

**US Inclusion and Diversity Steering Group Mission Statement**

National Grid is committed to creating a climate that values, respects, appreciates, and celebrates the unique differences of all employees, stakeholders, and customers. With that in mind, the Company has formed a US Inclusion and Diversity Steering Group to develop, implement and institutionalize strategies that result in a more inclusive and diverse workforce at National Grid.

*National Grid's Mission Statement provides:*

> *"We will develop and operate our business in a way that results in a more inclusive and diverse culture. This will enable us to attract and retain the best people, improve our effectiveness, deliver superior performance and enhance the success of the Company.*
>
> *We will ensure all our employees, regardless of race, gender, gender identity, nationality, age, disability, sexual orientation, religion and background, have the opportunity to develop to their full potential. We will prevent artificial or prejudicial barriers from getting in the way of their development.*
>
> *We will continually increase the diversity of our workforce in order to reflect the composition of the communities in which we serve, at all levels of the company.*
>
> *We will be widely perceived by both internal employees and external stakeholders as a company that values diversity, and as a company of choice, across diverse communities.*

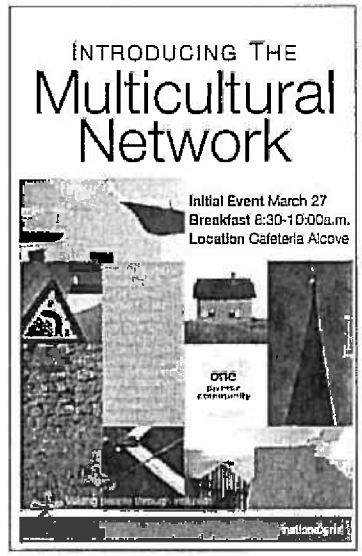
We believe:

- Fostering diversity is everyone's responsibility,
- Open, honest and respectful communication is the cornerstone of good business,
- A positive approach to Inclusion and Diversity is not a "nice to have" but is fundamentally the right thing to do for us as a business.

**Governance Structures, Employee Networks and Local Inclusion and Diversity**

*Task Forces*

National Grid has a corporate Inclusion and Diversity Council that monitors inclusion and diversity progress and advises the Company on overall strategy. Employee networks are supported and cultivated. These include NewNetUSA (a group for new hires managed and run by new hires), WiN (Women in Networks), and ONE Diverse Community (multicultural network). Regional inclusion and diversity task forces also are maintained. These teams of employees support awareness and celebratory inclusion and diversity activities to reach field force and divisional staff.




*National Grid's inclusion and diversity activities include awareness and celebration events, as well as employee networks.*

*Inclusion and Diversity Staff*

National Grid has a Director of Inclusion and Diversity and a Senior Human Resources Diversity Representative on staff.

*Leadership Accountability*

National Grid holds leadership accountable for inclusion and diversity through the goals requirements of its management performance process.

*External Benchmarking*

National Grid participated in the Human Rights Campaign Corporate Equality Index and Diversity Inc's Top 100 survey for the first time in 2006. The Company remains committed to participating in these benchmarking forums going forward.

Set forth below is diversity data for FY07:

| *Gender:* | Female | % Female | Male | % Male | Total | Average Salary Female | Average Salary Male |
|---|---|---|---|---|---|---|---|
| Sr Mgmt | 57 | 24.57% | 175 | 75.43% | 232 | $146,871 | $145,799 |
| Mid Mgmt | 824 | 28.65% | 2052 | 71.35% | 2876 | $ 67,539 | $ 80,047 |
| Admin | 127 | 97.69% | 3 | 2.31% | 130 | $ 42,884 | $ 37,801 |
| Field | 1185 | 22.12% | 4173 | 77.88% | 5358 | $ 50,693 | $ 63,427 |

| *Ethnicty* | White | % White | Minority | % Minority | Total |
|---|---|---|---|---|---|
| Sr Mgmt | 226 | 97.41% | 6 | 2.59% | 232 |
| Mid Mgmt | 2659 | 92.45% | 217 | 7.55% | 2876 |
| Admin | 127 | 97.69% | 3 | 2.31% | 130 |
| Field | 4827 | 90.09% | 531 | 9.91% | 5358 |

| *Age Groups* | Under 30 | % Under 30 | Between 30 - 50 | % Between 30 - 50 | >50 | % Over 50 | Total |
|---|---|---|---|---|---|---|---|
| Sr Mgmt | 0 | 0.00% | 141 | 60.78% | 91 | 39.22% | 232 |
| Mid Mgmt | 161 | 5.60% | 1731 | 60.19% | 984 | 34.21% | 2876 |
| Admin | 4 | 3.08% | 65 | 50.00% | 61 | 46.92% | 130 |
| Field | 223 | 4.16% | 3120 | 58.23% | 2015 | 37.61% | 5358 |

***Supplier Diversity Advancements***

The Company participated for the first time in The 2006 Diversity Inc Top 50 Companies for Diversity® survey, one of the most highly recognized and comprehensive benchmark surveys for overall diversity in the United States.

In its seventh year, The Diversity Inc Top 50 Companies for Diversity® survey uses standard parametric and non-parametric statistical techniques. Competition increased this year, with 317 companies participating, a 100 percent increase over the last three years and a 24 percent increase over last year.

*The survey is composed of four major components:* Executive Office Commitment, Human Capital, Corporate Communications and Supplier Diversity. National Grid fared best in the latter category. The Company was measured on the quality and intensity of its supplier-diversity effort. Measurements included:

- Percent of procurement going to minority-owned businesses
- Percent of procurement going to women-owned businesses
- Tier II (subcontractor) spending
- Third-party certification
- Auditing supplier-diversity results

National Grid achieved a score of 62.1 compared to 55.4 for the average of all companies for supplier diversity. Overall, the Company achieved a score of 23 versus a 35.8 average, which means that it did better than 23 percent of the total.

National Grid's Procurement operation has sharpened its focus and stepped up its proactive strategy implementation with respect to supplier diversity. That includes improving its supplier database (working to upgrade and qualify women and minority-owned businesses), increasing its external presence among minority vendor communities and thinking about the best way to improve Tier II spending as a large purchaser. This last area is critical to a large company such as National Grid in terms of establishing a logical approach to bulk buying. Tier II relates to large suppliers the Company might purchase from and how they are doing with their diversity commitment.

**HRC Survey Participation**

National Grid also participated in HRC's Corporate Equity Index. This survey is rooted in LGBT (Lesbian, Gay, Bisexual, Transgender) diversity and equality – how the Company treats LGBT employees.

With a score of 75 out of 100, National Grid performed well for the first time participating. The Company scored higher than the average score of 67 among the 27 utilities that participated, and was the highest among the six utilities participating for the first time this year.

## ◆ Human Rights

The way National Grid works and how it invests affects people's lives and their rights. The Company's operations are in countries where respect for human rights is generally high, but our impact stretches around the globe, most notably through the supply chain. We need to be sure our human rights policies – set out in our Public Position Statement on Human Rights – are upheld wherever we work.

National Grid puts its public commitment to human rights into practice in several ways:

1. *Our Framework for Responsible Business.*

   The Framework defines the principles by which we manage our business, sets the context for corporate governance, and helps us take account of economic, environmental and social factors in our decisions. It includes a specific principle to respect human rights, as well as other principles covering many individual rights, such as the right to safety, the right to non-discrimination, and the right to freedom from bribery and corruption.

2 *Setting the Context – Public Position Statement on Human Rights.*

An important first step in respecting human rights was publicly setting out our commitment to protect human rights within our sphere of influence and to ensure that our own operations are a force for good, wherever we operate in the world. In May 2003, the National Grid Board approved its Public Position Statement on Human Rights, which states that all employees are responsible for having a high regard for human rights. In particular:

- The Board has overall responsibility for ensuring that human rights considerations are integral to the way in which existing operations and new business opportunities are developed and managed.
- Managers and supervisors provide visible leadership that promotes human rights as an equal priority to other business issues.
- We are all responsible for ensuring that our day-to-day actions and behaviors protect the human rights of those with whom we work and those that are affected by our operations, wherever we operate in the world.

3 *Influencing the Debate – Business Leaders Initiative on Human Rights.*

National Grid is a founding member of the Business Leaders Initiative on Human Rights (BLIHR), a group of 14 multi-national companies. BLIHR aims to develop practical ways of applying the aspirations of the Universal Declaration of Human Rights within a business context and to inspire other businesses to do likewise.

4 *Defining What We Do – The Human Rights Matrix.*

The Human Rights Matrix was developed in 2004 by National Grid as its contribution to BLIHR's commitment to advance simple, practical tools to allow other businesses to assess their impacts on human rights and identify associated risks and opportunities. The matrix is a mapping tool that can be used to quickly assess the connection between a company's business activities and human rights. Specifically, the matrix provides insight into activities regarded as essential, expected and desirable behavior.

5 *Early Identification of Risks and Opportunities – Due Diligence.*

We have now developed a two-stage process for the due-diligence of human rights risks and opportunities related to potential new business through the use of protocols developed with the assistance of Amnesty International's UK business group.

6 *Managing our Risks – Human Rights and Supply Chain Training.*

The 2004 review of the National Grid Human Rights Matrix highlighted the need to better understand any potential human rights risks arising as a result of our increasingly global supply chain. To improve control in this area, our UK and US supply chain management teams have completed basic human rights training, and we have carried out an initial assessment of the full range of materials and services purchased across the Company to establish if and where there might be human rights issues in our supply chain.

7 *Taking a Leadership Stance – General Advocacy.*

Finally, an important part of developing National Grid's approach to human rights is encouraging others, particularly those we work with, to do the same.

Through these steps, National Grid is taking a proactive stance to protect human rights.

## ◆ Community Involvement

As part of its social commitment, National Grid has a long-standing tradition of investment in the community, through both the activities of our employees and our financial contributions. We are literally connected to more than four million customers in nearly 900 communities across our service territory. Just as our customers and communities are diverse, so too is our corporate giving program to meet those varied needs. Our efforts are targeted at improving and enriching the lives of a broad range of people in the communities where we live and work.

To that end, the Company has given generously with time, talent and financial support to hundreds of non-profit organizations throughout our service territory. We have given preference to organizations that provide support for health and social services, environmental protection, education, cultural institutions and civic organizations.

The following statistics refer to our Fiscal Year 2007 giving.

**United Way**

Each year, National Grid employees organize a United Way campaign at all company locations to benefit more than 40 local United Way chapters throughout our service territory in New York and New England. Money is collected through employee payroll deductions, cash, personal checks, retiree donations and various fund-raising activities.

In Fiscal Year 2007, employees and retirees exceeded the National Grid goal of raising $1 million by nearly $30,000. With National Grid's dollar-for-dollar match, the combined total by National Grid and its employees was nearly $2.1 million.

In addition to the financial contributions, employees have been active participants and volunteers with the United Way. Some participate on local United Way chapter boards, others serve as loaned executives and many more volunteer to help with local projects, including the United Way's annual Day of Caring, when volunteers provide the manpower necessary to help local organizations with facility repairs, painting and other cleanup activities.

**Share the Warmth – Energy Fuel Assistance Programs**

Second only to the United Way giving, National Grid donates a considerable sum of money towards energy fuel assistance programs to help households that are having extreme difficulty making their heating or electricity bill payments.

In Massachusetts and Rhode Island, the program is called The Good Neighbor Energy Fund (GNEF), and it is administered by the Salvation Army. The GNEF is a cooperative effort among Massachusetts and Rhode Island utilities. In its 22nd year, the GNEF has raised more than $20 million and assisted nearly 96,000 families.

In New York, a similar program called the Care and Share Fuel Fund is sponsored solely by National Grid for its customers and is administered by the Red Cross. The fund provides grants to households in which a member is 60 years old or older and meets eligibility criteria, by receiving disability income or having a medical emergency.

Since its inception in 1984, Care and Share has raised more than $7 million and assisted almost 34,000 families.

National Grid encourages its employees and customers to contribute to the respective funds in their state, and then we match these donations up to a specified maximum. To further encourage the general public to contribute, we often pay for promotional advertising as well as provide donation envelopes with the electric and gas bills.

## Cultural

Cultural events provide an opportunity to listen to some of the greatest music ever written, view artist renderings of scenes and people from places both far and near, and enjoy the squeals of delight as children see new animals or historic artifacts for the first time. We believe these cultural organizations help build and preserve the fabric of our communities.

To help support these programs and experiences, National Grid contributes to a range of organizations, including the Adirondack Theater Festival (Glens Falls, NY), Buffalo Philharmonic Orchestra (Buffalo, NY), Mass. Museum of Contemporary Art, Syracuse Symphony (Syracuse, NY), the Museum of Science and Technology (Syracuse, NY), Providence Performing Arts Center (Rhode Island), Roger Williams Park Zoo (Providence, RI) and the Worcester Art Museum (Worcester, Mass.)

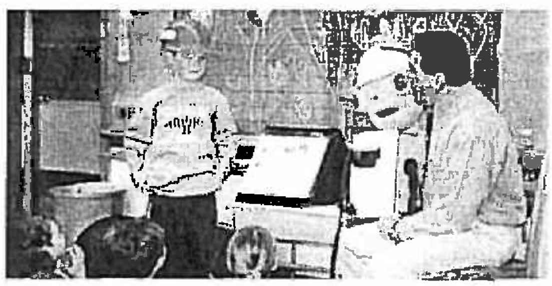
In Massachusetts, National Grid's involvement with the Worcester Art Museum has provided free admission to the museum on Saturday mornings to the general public.

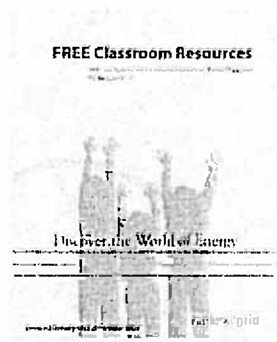
"Since National Grid first began supporting this program in 1995, the Museum has welcomed more than 182,000 visitors free-of-charge during the Free Saturday Mornings program," said Anne Sadick, corporate, foundation and government grants coordinator for the museum. "The Worcester Art Museum is grateful and honored to have your sponsorship of this valuable program."

## Education – An Investment in Our Future

National Grid considers education an important investment in our society's future and has long been a strong supporter of educational organizations.

In addition to its charitable contributions to several educational institutions and programs, the Company has partnered with elementary schools throughout its service territory for more than 20 years, offering free energy-related resource materials, including electricity safety classroom programs, educational booklets, posters and videos. Each school year, National Grid ships more than 250,000 energy-related materials per teachers' requests and presents more than 2,000 classroom electricity programs reaching more than 50,000 students.






*National Grid provides energy-related materials and programs to elementary schools throughout its service territory.*

The objective is to educate students on the need for safety around electricity and to promote energy conservation to help sustain future generations – all at no cost to the schools. These programs and materials enhance and complement teachers' curricula, and they instill positive messages and lasting impressions. During a 20-year span, National Grid has reached more than 1 million students face-to-face through its classroom programs, and has shipped nearly 4 million booklets, videos and posters to teachers.

### Engineering College Sponsorships

National Grid maintains a well-developed relationship with several key universities in our service area and supports activities ranging from basic research to internships to student capstone design programs. Universities also serve as a resource for National Grid staff who seek access to the talented expertise of educators for problem-solving, as well as access to emerging research that could have a future impact on the energy delivery business.

Following is a list of engineering colleges we support:

| | |
|---|---|
| Clarkson University | Union College |
| Rensselaer Polytechnic Institute | UMass Lowell |
| Syracuse University | Worcester Polytechnic Institute |
| University of Buffalo | University of Rhode Island |
| Northeastern University | University of New Hampshire |

### Junior Achievement

For more than 30 years, National Grid employees have been actively involved with local Junior Achievement (JA) programs. Each year numerous employees volunteer to present JA classroom lessons to hundreds of students. Employees are also involved with JA's Company or Entrepreneur Program, where a team of employee volunteers guides students in forming their own companies. Students manufacture and sell a product and perform all normal business record keeping, including selling stock.

In addition to corporate financial support and mentors in the classroom, our employees serve on JA boards and participate in fundraising events. National Grid and our individual employees have been recognized often with awards for dedication to, participation in, and support of JA programs.

### National Grid Scholarship Programs

The Samuel Huntington Public Service Award was created in 1988 in memory of the late president and chief executive officer of the former New England Electric System – now National Grid. Samuel Huntington was an advocate of public service, having spent a year in Nigeria teaching science and mathematics before pursuing his career in industry.

*The Samuel Huntington Public Service Award is presented annually by Jennifer Huntington (center), chairman of the Samuel Huntington Fund.*

The award, funded by colleagues, family and friends at National Grid, offers grants of $10,000 each to two graduating college seniors on the basis of their academic records, personal accomplishments and proposal for a public service project anywhere in the world.

The Samuel Huntington Award has enabled more than 30 college graduates to give back to their local and international communities through public service projects.

### Environmental

Each year National Grid and its employees sponsor and participate in Earth Day cleanup activities, as well as in Arbor Day and tree planting donations to schools, municipal offices, parks and other community facilities. We support educational programs and a variety of partnerships with various non-profit environmental organizations.

National Grid believes education is key and has been a long-time supporter of the New York, Massachusetts and Rhode Island Envirothons, an environmental education program for high school students that culminates in an annual statewide competitive event. The goal of the Envirothon is to increase awareness about environmental issues and help students gain a better understanding of natural resource issues, as well as cultivate their desire to learn more about local, state, national and global environments. In addition to financial support and in-kind services, National Grid employees, including arborists, foresters and environmental engineers, volunteer their time helping to organize and judge the state competitions.



### Health and Social Services

Ensuring the health, safety and well being of our friends, families and neighbors strengthens our communities. By participating with and donating funds to health and social service organizations, National Grid aims to share in the responsibility of caring for our communities.

In addition to financial contributions from the Company, National Grid employees participate in local events such as the American Heart Walk, the American Cancer Society's Relay for Life, AIDS walks, the Juvenile Diabetes Research Foundation Walk to Cure Diabetes, and mentoring programs with local Boys and Girls Clubs of America, to name a few.

### Matching Gifts, Employee Volunteer Grants and Chairman's Awards

#### *Matching Gifts*

National Grid's Matching Gifts Program maximizes employees' donations to eligible non-profit organizations. Through the program, qualified gifts are matched dollar for dollar by the Company, up to a maximum of $3,500 per employee, per year.

Our employees support diverse organizations ranging from Harvard University and the Make a Wish Foundation to the Pan-Massachusetts Challenge and the American Heart Association, as examples. In FY07, National Grid matched more than $476,000 of employee donations to more than 600 different organizations.

#### *Employee Volunteer Grants*

National Grid established the Employee Volunteer Grants Program to recognize employees who are actively involved with non-profit organizations within their communities; employees apply for grants on behalf of their volunteer activities. We select requests that meet specific criteria and then make a financial donation to those organizations in the name of the employee volunteer. The program is administered by a committee that meets twice a year to review and select applications for grants. The maximum grant is $2,000.

In Fiscal Year 2007, grants totaling more than $30,000 were distributed to organizations that included senior centers, schools, Boy Scout troops, Boys and Girls Clubs, fire departments, Little League teams and various health and service organizations.

#### *Chairman's Awards*

In 2004, National Grid established the US Chairman's Awards for Safety, Health and Environmental Achievement to encourage innovation and continuous improvement in these areas. All employees, or teams of employees, are eligible for nomination. The employee or team, through exceptional effort or an innovative idea, must clearly demonstrate a contribution to safety, health or environmental improvements for employees or the general public.

A winner of each category is selected, as well as an overall winner. Winning teams and/or individuals are presented with a check of $20,000 to donate to a charity of their choice. The overall winner receives an additional $10,000 to donate.

## ◆ The Future

In August 2007, National Grid acquired KeySpan Corporation of Brooklyn, New York. As a result of the acquisition, National Grid becomes the second largest utility in the United States by number of customers. With this growth of the Company, sustainability, reliability, and social issues will become an even more critical component of the Company's operations.

Toward those ends, National Grid has set a number of priorities going forward. These include improving safety performance; integrating the KeySpan acquisition; delivering on the capital investment program; improving reliability levels in the United States; focusing on the development of employees, continuing to mitigate climate change through programs, policies and procedures; and enhancing value for shareholders, customers, employees and the communities we serve.

With its strong, committed workforce, National Grid is well-positioned to meet these objectives, fulfill growing demand for safe and reliable electricity and natural gas, and continue to grow in the process.

## Summary of Key Performance Indicators for National Grid US (FY 2007)

| Indicators | Historical Performance | FY 2007 Performance |
|---|---|---|
| **I Company Overview** | | |
| Square Miles in Service Area | FY 05: 29,000 Sq. Miles.<br>FY 06: 29,000 Sq. Miles | 29,000 Sq. Miles |
| Number of Customers | FY 05: 3.2 Million<br>FY 06: 3.3 Million | FY 07: 3.3 Million |
| Miles of Transmission and Distribution | FY 05: 72,000 Distribution, 14,000 Miles Transmission and Subtransmission | 8,000 Miles of Transmission Overhead |
| | FY 06: 9,000 Miles Transmission, 72,000 Miles Distribution | 89 miles of Underground cable<br>11,800 Miles of Natural Gas Pipeline Lines |
| Electricity Delivered (TWh) | FY 05: 67,458,979 (TWh)<br>FY 06: 67,968,792 (TWh) | 72,000,820 TWh |
| **II Economic Performance** | | |
| Number of Customers Taking Advantage of Low Income Customer Assistance | | 16,000 |
| WMBE Spending | | $35 Million |
| **III Environmental Performance** | | |
| Energy Use (KWh) | FY 05: 113,972,248<br>FY 06: 937,976,095 | 107,420,083 |
| Water Use (Gallons) | FY 05: 54,923,578<br>FY 06: 35,521,939 | 40,275,086 |
| Percentage of Electricity Purchased by National Grid from Renewable Sources (%) | FY 05: 51%<br>FY 06: 42% | 45% |
| Fuel Use/Fleet (Gallons) | FY 05: 3,183,308<br>FY 06: | 2,793,124 |
| $CO_2$ Emissions (Tons/yr.) | 2004: 27,354<br>2005: 17,968 | 2006: 32,237 |
| Methane Emissions (Tons/yr.) | 2004: 224<br>2005: 138 | 2006: 126 |
| $SF_6$ Emissions (lbs/yr.) | 2004: 12,471<br>2005: 12,316 | 2006: 12,249 |
| CFCs & HCFCs (lbs/yr.) | 2004: 6,431<br>2005: 4,878 | 2006: 2,413 |
| Participation by Residential and Business Customers in Energy Efficiency Programs | | 382,745 Customers |
| Total Lifetime MWh Savings due to Energy Efficiency Programs | | 2,871,561 |
| Hazardous Waste Generated (Tons) | FY 05: 354 tons<br>FY 06: 354 tons | 475 tons |
| Non-hazardous Waste Generated (Tons) | FY 05: 5610 tons<br>FY 06: 5610 tons | 5,627 tons |
| Recycled Waste (Tons) | FY 05: 11,301 tons<br>FY 06: 11,301 tons | 10,317 tons |
| Spills | FY 05: 20 Category 1<br>695 Category 2<br>FY 06: 38 Category 1<br>1,044 Category 2 | 30 Category 1<br>977 Category 2 |
| NOVs | FY 05: 14<br>FY 06: 9 | 8 |
| **IV Social Performance** | | |
| Number of Employees | | 8,270 |
| LTIs in Workforce/Contractors | | 91 |
| Amount of Money Given as Corporate Philanthropy | | $2,054,982 |

The table below shows how this report aligns with the Global Reporting Initiative (GRI) Performance Indicators, which we use as an important guide and reference point. While we are working toward meeting the GRI reporting protocols, for several indicators below, we currently only partially meet the recommended standard.

| | Indicator Description | Page(s) |
|---|---|---|
| **Strategy and Analysis** | | |
| 1.1* | Statement by the CEO | 5-6 |
| **Organizational Profile** | | |
| 2.1 | Name of organization | 11 |
| 2.2 | Primary brands, products, or services | 11 |
| 2.3 | Operational structure of organization | 11 |
| 2.4 | Location of organization headquarters | 11 |
| 2.5 | Countries in which the Company has operations | 11 |
| 2.6 | Nature of ownership and legal form | 11 |
| 2.7 | Markets serviced | 11 |
| 2.8 | Scale of the reporting organization | 11, 12, 51 |
| 2.9 | Significant changes during the reporting period | 11-12 |
| 2.10 | Awards received during the reporting period | 15, 49, 50 |
| **Report Parameters** | | |
| 3.1 | Reporting period | 9 |
| 3.2 | Date of most recent previous report | 9-10 |
| 3.3 | Reporting cycle | 10 |
| 3.4 | Contact point for questions regarding the report or its contents | 10 |
| **Report Scope and Boundary** | | |
| 3.5 | Process for defining report content | 8-10 |
| 3.6 | Boundary of the report | 9-10 |
| 3.7 | State any specific limitations on the scope or boundary of the report | 9 |
| 3.11 | Significant changes from previous reporting period | 9-10 |

| Indicator | Description | Page(s) |
|---|---|---|
| **GRI Content Index** | | |
| 3.12 | Table identifying the location of the standard disclosures in the report | 69-79 |
| **Assurance** | | |
| 3.13 | Policy and current practice with respect to securing external assurance for the report | 10, 80 |
| **Governance** | | |
| 4.8 | Internally developed statements of mission or values | 13-15 |
| 4.9 | Procedures of the highest governance body for overseeing the organization's identification and management of economic, environmental, and social performance | 13-15 |
| **Commitment to External Initiatives** | | |
| 4.13 | Memberships in associations | 16 |
| **Stakeholder Engagement** | | |
| 4.14 | Stakeholder groups engagement by the organization | 9-10 |
| 4.15 | Identification and selection of stakeholders | 9-10, 23 |
| 4.16* | Approaches to stakeholder engagement | 9, 23 |
| 4.17 | Key topics and concerns raised through stakeholder engagement | 8, 9 |
| **Economic Performance** | | |
| EC3 | Coverage of the organization's defined benefit plan obligations | 52 |
| EC8 | Development and impact of infrastructure investments and services provided primarily for public benefit through commercial, in-kind, or pro bono engagement | 19-20 |
| **Environmental** | | |
| EN5 | Energy saved due to conservation and efficiency improvements | 32 |
| EN6 | Initiatives to provide energy-efficient or renewable energy based products and services, and reductions in energy requirements as a result of these initiatives | 31-34 |
| EN7 | Initiatives to reduce indirect energy consumption and reductions achieved | 31-34 |
| EN12 | Description of significant impacts of activities, products, and services on biodiversity in protected areas and areas of high biodiversity value outside protected areas | 44-47 |
| EN13 | Habitats protected or restored | 44-47 |

| | Indicator Description | Page(s) |
|---|---|---|
| EN14 | Strategies, current actions, and future plans for managing impacts on biodiversity | 44-47 |
| EN16 | Total direct and indirect greenhouse gas emissions by weight | 68 |
| EN18 | Initiatives to reduce greenhouse gas emissions and reductions achieved | 29-35 |
| EN19 | Emissions of ozone-depleting substances by weight | 31 |
| EN22* | Total weight of waste by type and disposal method | 36-37, 68 |
| EN23 | Total number and volume of significant spills | 40-41 |
| EN24 | Weight of transported, imported, exported, or treated waste deemed hazardous under the terms of the Basel Convention Annex I, II, III, and VIII, and percentage of transported waste shipped internationally | 36 |
| EN26 | Initiatives to mitigate environmental impacts of products and services, and extent of impact mitigation | 44-47 |
| EN28 | Monetary value of significant fines and total number of non-monetary sanctions for non-compliance with environmental laws and regulations | 40 |
| **Social Performance** | | |
| LA1 | Total workforce by employment type, employment contract, and region | 51 |
| LA4 | Percentage of employees covered by collective bargaining agreements | 51 |
| LA7* | Rates of injury, occupational diseases, lost days, and absenteeism, and number of work-related fatalities by region | 55-57 |
| LA10 | Average hours of training per year per employee by employee category | 60 |
| LA11 | Programs for skills management and lifelong learning that support the continued employability of employees and assist them in managing career endings | 60 |
| LA13 | Composition of governance bodies and breakdown of employees per category according to gender, age group, minority group membership, and other indicators of diversity | 62 |
| LA14 | Ratio of basic salary of men to women by employee category | 62 |

| | Indicator Description | Page(s) |
|---|---|---|
| **Society** | | |
| SO2 | Percentage and total number of business units analyzed for risks related to corruption | 15 |
| SO3 | Percentage of employees trained in organization's anti-corruption policies and procedures | 13-15 |
| SO4 | Actions taken in response to incidents of corruption | 13-15 |
| SO5 | Public policy positions and participation in public policy development and lobbying | 16 |
| SO8 | Monetary value of significant fines and total number of non-monetary sanctions for non-compliance with laws and regulations | 40 |
| **Electric Utility Supplement** | | |
| EU1* | Percentage of population served in area of operation, according to category (e.g., rural, commercial, residential, etc.) | 11, 12 |
| EU2 | Length of transmission and distribution lines | 13 |
| EU24 | Processes to ensure retention and renewal of skilled workforce | 51-54, 60 |
| EU25* | Participatory decision making processes with communities and outcomes of engagement | 47-48 |
| EU30 | Programs, including those in partnership with government, to assist underprivileged, low-income or vulnerable customers to afford electricity connection and consumption | 19-20 |
| EU37 | Demand-side management programs including residential, commercial and industrial programs | 31-34 |
| EU40 | Approaches for conducting alternatives analysis of new investments | 47-48 |

* **Partial conformance** – defined as completing at least 50% of the content required by the GRI Guideline.

## ◆ ESS Verification Statement

**Assurance Statement of the Certified Environmental Auditor**

ESS Group, Inc. (ESS) was hired by National Grid US (National Grid) to conduct an independent review of its Corporate Responsibility Report for Fiscal Year 2007 (the Report). The purpose of the review was to determine the level of National Grid's conformance to the GRI Guidelines, including the draft Electric Utility Sector Supplement.

Under the direction of a RABQSA Certified Environmental Auditor, an audit plan was developed and implemented with the assistance of ESS. The audit plan called for the review of applicable GRI Guidelines, including the draft Electric Utility Sector Supplement, as determined by National Grid.

The audit team determined that National Grid conformed with 63 out of the total 163 GRI Guidelines, as listed in the table below. Descriptions of GRI Guidelines are listed elsewhere in the report.

| | | | | | | |
|---|---|---|---|---|---|---|
| 1.1 (Partial*) | 2.1 | 2.2 | 2.3 | 2.4 | 2.5 | 2.6 |
| 2.7 | 2.8 | 2.9 | 2.10 | 3.1 | 3.2 | 3.3 |
| 3.4 | 3.5 | 3.6 | 3.7 | 3.11 | 3.12 | 3.13 |
| 4.8 | 4.9 | 4.13 | 4.14 | 4.15 | 4.16 (Partial) | 4.17 |
| EC3 | EC8 | EN5 | EN6 | EN7 | EN12 | EN13 |
| EN14 | EN16 | EN18 | EN19 | EN22 (Partial) | EN23 | EN24 |
| EN26 | EN28 | LA1 | LA4 | LA7 (Partial) | LA10 | LA11 |
| LA13 | LA14 | SO2 | SO3 | SO4 | SO5 | SO8 |
| EU1 (Partial) | EU2 | EU24 | EU25 (Partial) | EU30 | EU37 | EU40 |

** Partial conformance is defined by completing at least 50% of the content required by the GRI Guideline.*

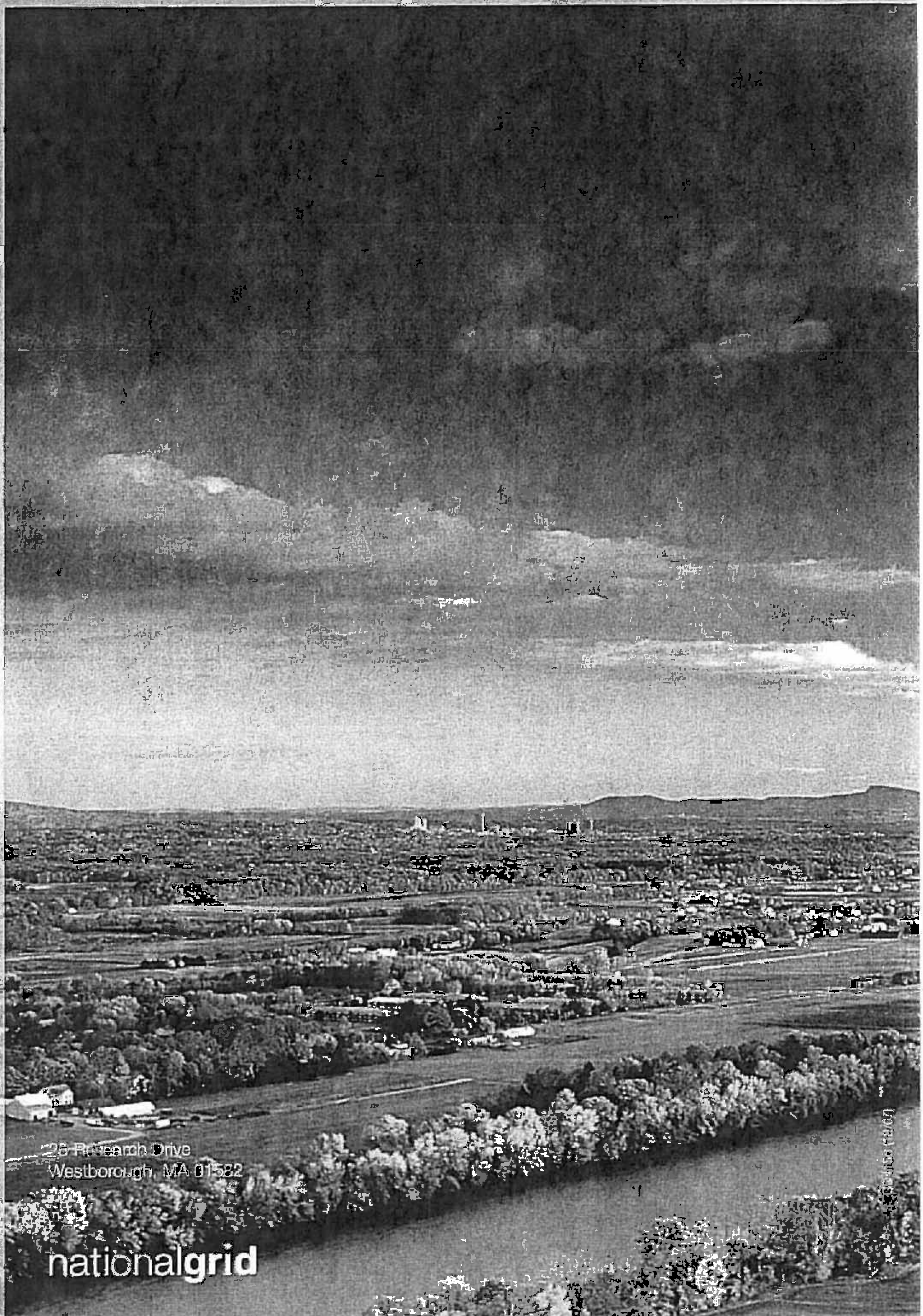
As clearly stated by National Grid, this was the first year in which the GRI Guidelines were considered as part of the Report. It is the understanding of the reviewers that future reports will take into account additional GRI Guidelines.

Julie T. Davies
*RABQSA Certified Environmental Auditor*

ESS Group, Inc. is a multidisciplinary environmental engineering and consulting firm located in Wellesley, Massachusetts and East Providence, Rhode Island. ESS has extensive experience related to environmental compliance and auditing in the US energy and industrial sectors.

## ◆ Notes

**Photography:** Unless noted, National Grid sites, employees and activities were photographed by National Grid's Randy Calkins. The cover and environmental images on page 23 were photographed by Patrick Pacheco Zephyr, Pelham, Mass. The Ward Hill substation images are by David Parnes Photography, Concord, Mass. The line hardening image on page 19 is by James Bell of the UK.


25 Research Drive
Westborough, MA 01582
nationalgrid

# STATE OF NEW HAMPSHIRE
# BEFORE THE
# PUBLIC UTILITIES COMMISSION



**EnergyNorth Natural Gas, Inc.**
**d/b/a National Grid NH**

**Docket DG 08-009**

**Direct Testimony**
**Of**
**Paul M. Normand**

**February 25, 2008**

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## LIST OF ATTACHMENTS

## I. INTRODUCTION

**Q. Would you please state your name, address and business affiliation?**

A. My name is Paul M. Normand. I am a principal with Management Applications Consulting, Inc. ("MAC"), 1103 Rocky Drive, Suite 201, Reading, Pennsylvania 19609.

**Q. Please describe MAC.**

A. MAC is a management consulting firm which provides rate and regulatory assistance including depreciation services for electric, gas and water utilities.

**Q. Would you please summarize your education and business experience?**

A. This information is contained in Attachment PMN-1.

**Q. What are your responsibilities in this proceeding?**

A. I am responsible for the preparation of the depreciation study for National Grid NH ("the Company"), which includes coordinating data collection, ensuring the reasonableness of the data and properly reflecting any accounting adjustments. Beyond data collection, I am responsible for the performance and interpretation of statistical analyses and the preparation of appropriate schedules to reflect the results of the study.

## II. PURPOSE OF TESTIMONY

**Q. Please discuss the purpose of your testimony.**

A. Our consulting firm has been retained by National Grid NH to conduct a depreciation rate study.

## III. DEPRECIATION STUDY

**Q. What is the definition of depreciation?**

A. The National Association of Regulatory Utility Commissioners (NARUC) has adopted the following definition of depreciation:

> *"Depreciation," as applied to depreciable utility plant, means the loss in service value not restored by current maintenance incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.*

Another commonly referenced definition of depreciation is that of the American Institute of Certified Public Accounts (AICPA):

> *Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.*

The two foregoing citations are found on pages 13 and 14, respectively, of "Public Utility Depreciation Practices," August 1996, by the NARUC Staff Subcommittee on Depreciation.

The AICPA definition helps clarify the NARUC definition in that it brings to the description the process of allocation of cost.

**Q. What is the purpose of conducting a periodic book depreciation rate study?**

A. Consistent with the definitions above, the purpose of a depreciation study is to develop depreciation accrual rates reflective of engineering judgment, current industry and specific company experience, and current projections for the future, relative to the particular depreciable assets under study. In other words, these accrual rates are prospective in nature. The importance of judgment and projections, as to the future cannot be over emphasized as the accrual rates developed are for the near-term future, <u>not the past</u>. The objective of depreciation as an element of the cost of service is to provide for the appropriate and equitable recovery of the investments in depreciable assets over a life term that assures the full recovery of the investments less estimated net salvage.

**Q. Have you prepared a depreciation study for National Grid NH?**

A. Yes. The results of this study are shown in a report entitled, "Depreciation Rate Study – Depreciation Accrual Rates Based on Gas Plant in Service at December 31, 2006" ("the Depreciation Study") identified as Attachment PMN-2.

**Q. What procedures did you employ in compiling the depreciation study?**

A. First, the depreciation study databases were created. The Company provided MAC with available property accounting history to develop databases for each relevant account to December 31, 2006. The Company also provided MAC with recent plant account level gross salvage and removal cost history. In addition, I inspected the actual physical plant facilities in New Hampshire and held discussions with Company personnel concerning matters relevant to this depreciation study.

The historical data was analyzed using computerized statistical routines and the output was evaluated in light of the data from the Company, the character of the depreciable assets, knowledge gained during property inspections, MAC's experience with like assets, and engineering knowledge and judgment. Final calculations were then made to develop the recommended accrual rates for each category of plant as shown in the Depreciation Study (Attachment PMN-2) section entitled "Accrual Rate Schedule."

**Q. You previously referred to "statistical analyses." Please explain what is meant by this term.**

A. This term refers to Simulated Plant Record ("SPR") life analysis, a well known and well accepted technique employed in depreciation studies. Its purpose is as a tool that can assist in estimating the average life of an asset. An SPR life analysis can be performed whenever there is an adequate volume and frequency of additions and retirements.

SPR life analyses are known by some as "semi-actuarial life analyses." The SPR-Balances analysis used in these studies is an iterative procedure in which certain values (survivor factors) from empirical survivor curves (Iowa curves) are applied to a company's actual, recorded annual additions to generate theoretical surviving year-end balances. The procedure identifies the empirical curves that best simulate the actual ending balances in a specified band of years. As an example, the bands of balance years simulated in these studies were primarily 17 years (1990 to 2006) and 10 years (1997 to 2006).

The Iowa survivor curves used in our analyses were developed in the 1930s at Iowa State University; they are empirical curves whose equations are published, along with tables of various values, e.g., survivor factors at various ages. Iowa curves are widely accepted in the industry as a common and convenient means of communicating and calculating technical depreciation parameters.

As mentioned previously, the SPR life analyses of property history can be helpful in estimating the life of some historical investments, a starting point in the life estimation process; however, it must be noted that life analysis is <u>not</u> life estimation. Unfortunately, life analysis can only provide an indication as to what has happened in the past. In performing a depreciation study such as the one in this case, the goal is to estimate what will occur in the future, not merely measure the past.

**Q. Did you employ any analyses other than SPR to assist in the life estimation process?**

A. Yes. The pattern of annual additions to and retirements from the plant accounts were also reviewed to determine the relative volumes of capital activity. The volume changes can often assist in explaining why life and/or curve changes appear in the mortality analyses.

**Q. In evaluating the SPR life analyses, you previously stated that you also considered input from the Company. What type of information did you consider?**

A. MAC also conferred with the Company to determine if there were any occurrences, changes in policy, procedures, equipment, or practices which might affect service life, salvage, or removal cost associated with depreciable assets. The major consideration was to determine whether indications of the past would likely be representative of the near-term future.

**Q. Can you give any examples of specific input provided to you by the Company which influenced your life estimates?**

A. Yes. For example, the Company expects to replace and retire a much greater level of mains and services in the foreseeable future as compared to historical experience.

**Q. Your answers to previous questions indicate judgment and experience are significant elements in life estimation and in the interpretation of statistical analyses. Do other depreciation experts and authoritative sources concur?**

A. Yes, the literature is unambiguous on this point. For example, page I.1 of the New York State Department of Public Service publication, "Computer Supported Property Mortality Studies," published in 1971, states:

> *The purpose of an actuarial mortality study of public utility property is to make a statistical determination of a representative life table and average service life. The method used to derive these quantities in this report is that of smoothing and extending the retirement ratios.*
>
> *It must be clearly understood that the computer procedure explained in Section II accomplishes electronically only those computations which have had to be done manually, and nothing else. Because of the computer's large storage capacity and extremely fast running time, it is able to calculate a great deal more than has ever been obtained manually in the past.*
>
> *The computer exercises no judgment, reflects no opinions or company policies and does not forecast the future. The computer programs are merely the results of applying certain mathematical formulae to a set of statistics obtained from accounting records – and, based on these data and formulae give an indication of what has been the retirement experience of the past and what would be the future life pattern if the same experience were constant over the entire life of the surviving property under study.*
>
> *Under no circumstances should it be construed that a specific indicated service life and life table developed by this computer process must necessarily be used as the life table and average service life in arriving at a final estimate of annual and accrued depreciation. Stress is placed on the fact that the selected life table and average service life finally used, whether or not*

*developed by program PSU-2 or PSU-2A must be the engineer's best estimate for the property under study.*

**Q. Can you provide other citations?**

A. Mr. Alex E. Bauhan, the person who developed the SPR-Balances method of life analysis, cites the need for exercising judgment in his paper in which the method was introduced to the industry. In his paper, given in April 1947, to the National Conference of Electric and Gas Utility Accountants of the American Gas Association (AGA) and Edison Electric Institute (EEI), under the heading, "Multiple Indications," he states:

> *The method reads the past and not the future, and has no way of telling which patterns will be followed in the future. Neither the actuarial or any other statistical process can eliminate this dilemma. Only by the exercise of reasonable judgment, or by the passage of time, can a selection be made.*

In discussing the Retirement Experience Index, regarding the situation where the index is "poor or valueless," Mr. Bauhan states:

> *In all such cases, for estimating purposes, the result of the analysis should be discarded and a judgment figure should be substituted in place of it. In those cases where the experience index is only fair, the result should be examined critically, and if it is not supported by reasoned judgment, it should be accordingly modified.*

Mr. Bauhan's paper is found in the Edison Electric Institute Publication No. 51-23, titled, "Methods of Estimating Utility Plant Life" published in 1952; the foregoing citations are found on pages 61 and 63, respectively.

The Retirement Experience Index (REI) is the percentage of the accumulated retirements with the given Iowa curve from the oldest capital addition, e.g., if the oldest addition was 1930, by convention it would be 70.5 years old at year-end 2000. If the Iowa curve in question was a 35-year L 1.0, the REI would be 96;

that is, the 35-year L 1.0 Iowa curve shows 4 percent surviving at age 70.5 years, and 100 percent less 4 percent equals 96 percent.

In summary, life estimates consider many factors, including the importance of informed judgment.

**Q. Have you employed your judgment in this depreciation study?**

A. Yes. In the course of the depreciation study, MAC has conferred with Company management and operating personnel, conducted property inspections, reviewed and considered the types of property in the various primary plant accounts, and performed life analyses of the history of the property. MAC also relied upon its experience in doing similar studies as engineers and consultants in evaluating, interpreting and estimating the life analysis of utility property.

**Q. What was the purpose of the property inspections that you conducted?**

A. The inspections were intended to accomplish several functions. First and foremost, the inspections verified that the assets identified on the Company's books actually exist. Second, the inspections verified that the assets continue to be maintained and are useable. In addition, inspections facilitate discussions regarding the existing facilities with the Company personnel; these discussions provide a better understanding of the overall system, the equipment, and ongoing changes and improvements to the facilities.

**Q. What is the total composite annual accrual rate which results from your depreciation study?**

A. The composite of the proposed straight line, whole life individual account rates detailed in the depreciation study is 2.91% as shown in Schedule A, column 8 of the report along with the details for each account. These proposed accrual rates do not include any amortization of the depreciation reserve variance.

The accrual rate Schedule A, the "Schedule of Depreciation Accrual Rates, Whole Life Schedule with Amortization of Reserve Variance," also presents the differences (variances) between the actual book depreciation reserves and our computed (theoretical) reserves. In addition, these differences were amortized on an annual basis which will eliminate any reserve variances over the average remaining life of the various accounts. The composite accrual rates with remaining life amortization are shown in column 17 of Schedule A with the composite overall rate of 2.76%.

**Q. Can the Company utilize remaining life as an appropriate technique to recover the undepreciated capital investments of the Company?**

A. Yes, it can. The report presents an analysis of the Company's depreciable assets showing whole life and remaining life accrual rates on Schedule A. The average remaining life technique shown in columns 16 and 17 of Schedule A incorporates all of the Company's cost elements unique to each account and calculates an appropriate accrual rate that will assure full recovery of all of the relevant costs – no more, no less. The remaining life technique factors in the average service life with the survival characteristics, net salvage for each account, along with recognizing the level of accrued depreciation in arriving at the final recommended accrual rate.

**Q. Is the average remaining life technique a well recognized approach to use in developing appropriate accrual rates?**

A. Yes, it is. The remaining life technique is used extensively in the industry today. In fact, the NARUC manual on page 65 correctly addresses the proper use of the remaining life technique as follows:

> *The desirability of using the remaining life technique is that any necessary adjustments of depreciation reserves, because of changes to the estimates of life on net salvage, are accrued automatically over the remaining life of the property.*

**Q. Your depreciation study concludes (on page 10) that the net salvage (NS) estimates are lower (more negative) than those in the existing depreciation accrual rates. Why are your estimates lower?**

A. My estimates are lower than the existing because I have adjusted the proposed estimates <u>toward</u> the actual net salvage realized by the Company. The proposed estimates are very conservative representatives of actual experience, based on the data provided to us; i.e., the proposed net salvage values are considerably less negative than the actual Company experience.

**Q. What plant accounts did you consider in your proposed net salvage (NS) calculations?**

A. The net salvage factors incorporated into the proposed accrual rates were consistent with those included in the Company's existing accrual rates as shown below:

| **Plant Account** | **Proposed NS** | **Existing NS** |
|---|---|---|
| 1356 Mains | -15% | -10% |
| 1359 Services | -70% | -60% |
| 1372.1 Office Equipment | 5% | 5% |

As I mentioned earlier, these updated NS factors were only adjusted slightly from existing levels based on our calculations in order to be very conservative and yet move in the proper direction of cost recovery.

## IV. CONCLUSION

**Q. Does this complete your testimony?**

A. Yes.

# Attachment PMN-1

# Qualifications of Paul M. Normand

# PAUL M. NORMAND
**Principal**

Experience in the electric, gas, and water industry includes project management of various cost analyses, engineering system planning and design functions, and detailed electric power loss analyses. Also, experienced in the analysis and preparation of economic and plant data, revenue requirements and presentation before state and federal regulatory agencies. Presented expert testimony on behalf of utilities in over 30 applications before regulatory commissions.

## EXPERIENCE:

1984 - Present **MANAGEMENT APPLICATIONS CONSULTING, INC.**
Principal consultant providing consulting services to industry in planning, pricing, and regulation. Extensive experience in analyzing power systems for power loss studies and regulatory issues.

Assist in gathering and updating property accounting data for depreciation studies.
Review and analyze life analyses relating to simulated plant balances and actuarial data.
Perform property inspections to aid in service life estimation and salvage and removal cost estimations.

1983 - 1984 **P. M. NORMAND ASSOCIATES**
Independent consultant providing services to the utility industry in cost analyses, regulatory services and expert testimony.

1976 - 1983 **GILBERT/COMMONWEALTH**, Reading, Pa.
Director, Rate Regulatory Services - Administrative and fiscal responsibility for rate and regulatory services nationally for electric, gas, and water utilities. Additional responsibilities included all marketing, research and development efforts, and contract negotiations for all studies performed by the Regulatory Service Department. Provided consulting service to utilities in project management, personnel staffing, and future development efforts.

Manager, Austin, Texas Office - Responsibility for the overall administrative and business aspects for the department in the Southwest.

Senior Management Consultant - Responsibilities included project management of various electric and gas cost-of-service studies.

Consulting Engineer - Prepared class and time-differentiated cost-of- service studies, revenue requirements exhibits, and expert testimony for formal rate proceedings before regulatory agencies. Performed forecasted ten-year cost-of-service studies by customer classes. Analyzed and prepared transmission (wheeling) rates based on cost-of-service.

Engineer - Derived system demand and energy loss factors and customer load characteristics required for cost-of-service results and related rate schedules.

1975 - 1976 **WESTINGHOUSE ELECTRIC CORPORATION**, Pittsburgh, PA
Responsible for the procurement of electrical/electronic control equipment and power cables for the nuclear reactor control system. Assisted in the development of procedures for the seismic testing of various electronic equipment related to reactor control.

1971 - 1974 **NEW ENGLAND ELECTRIC SYSTEM**, Westborough, Massachusetts
Experience from various system assignments in conjunction with formal education. Assigned to the Transmission and Distribution Department with responsibilities in several voltage conversion efforts and system planning. Development of network modeling techniques, load flow, and fault study analyses for the system planning department.

1966 - 1970 **U.S. NAVY**
Aviation electronic technician with responsibilities for maintenance and trouble-shooting of electronic communication equipment.

**EDUCATION:**

B.S.E.E., Electrical Engineering, Northeastern University, 1975
M.S.E.E., Electrical Power Systems, Northeastern University, 1975

Graduate Studies - MBA Program, Lehigh University and Albright College, 1977 to 1980

**SOCIETIES:**

Institute of Electrical and Electronic Engineers

## APPEARANCES AS EXPERT WITNESS:

New Hampshire Public Utilities Commission
Massachusetts Department of Public Utilities
Federal Energy Regulatory Commission
Maine Public Utilities Commission
Public Utilities Commission of Texas
Arkansas Public Service Commission
Louisiana Public Service Commission
Illinois Commerce Commission
Kentucky Public Service Commission
Missouri Public Service Commission
New Jersey Board of Public Utilities
New York Public Service Commission
Pennsylvania Public Utility Commission
Delaware Public Service Commission
Maryland Public Service Commission
Indiana Utility Regulatory Commission
Kansas Corporation Commission

## PAPERS AND PRESENTATIONS:

"Probability of Dispatch Costing Method for Electric Utility Cost-of-Service Analysis." Co-authored with P. S. Hurley, presented to Edison Electric Institute Rate Research Committee May 4, 1982.

"Costing Strategies under Changing Marketing Goals and Long Term Investment Growth." Presented to Missouri Valley Electric Association (MVEA), Kansas City, MO, November 13, 1991.

# ENERGY NORTH NATURAL GAS, INC.
# D/B/A NATIONAL GRID NH

## <u>DEPRECIATION RATE STUDY</u>

**Depreciation Accrual Rates**
**Based on Gas Plant in Service**
**At December 31, 2006**

**National Grid NH**
**Depreciation Accrual Rates Based on**
**Gas Plant in Service at December 31, 2006**

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# LETTER OF TRANSMITTAL

February 15, 2008

Mr. John O'Shaughnessy
Director – Rate Case Management & Load Forecasting
National Grid NH
One MetroTech Center, 13th Floor
Brooklyn, NY 11201-3850

Dear Mr. O'Shaughnessy:

In accordance with the authorization of your organization, Management Applications Consulting, Inc. (MAC) has completed a depreciation rate study of the depreciable gas utility property of National Grid NH's plant in service as of December 31, 2006. The results of this study are presented in the attached report.

The study was accomplished by our organization, with the assistance of Ms. Najat Coye and others within your organization. Our depreciation study develops accrual rates defined as straight line, broad group, whole life and remaining life.

We appreciate the opportunity to have been of service.

Respectfully,

MANAGEMENT APPLICATIONS CONSULTING, INC.

Paul M. Normand

Enclosures

PMN/rjp

**National Grid NH**
**Depreciation Accrual Rates Based on**
**Gas Plant in Service at December 31, 2006**

# I. FOREWORD

**National Grid NH**
**Depreciation Accrual Rates Based on**
**Gas Plant in Service at December 31, 2006**

## I. FOREWORD

This report presents the results of a detailed study of the relevant characteristics of the depreciable gas plant in service of National Grid NH's property. The recommendations regarding annual depreciation accrual calculations have been developed on plant in service at December 31, 2006 and are applicable until subsequent studies indicate the need for revision. In our opinion, based on our analyses, experience and judgment, the straight line, broad group, whole life depreciation accrual rates developed herein will provide for the proper and timely recovery of capital invested in the depreciable gas properties.

**National Grid NH**
**Depreciation Accrual Rates Based on**
**Gas Plant in Service at December 31, 2006**

# II. SUMMARY

**National Grid NH**
**Depreciation Accrual Rates Based on**
**Gas Plant in Service at December 31, 2006**

## II. SUMMARY

### A. FINDINGS

Management Applications Consulting, Inc. ("MAC") has completed a study of the service life characteristics of certain capital investments of National Grid NH's ("the Company") depreciable gas property as of December 31, 2006. The study develops average service lives, mortality characteristics, net salvage estimates, whole life accrual rates, average remaining lives, the amortization of the reserve variance, and accrual rates with amortization for each depreciable investment group (subaccounts and accounts).

Net salvage is gross salvage less cost to retire/remove. Based upon these elements, the study develops straight line depreciation accrual rates using the whole life technique with and without the amortization of reserve variances over the average remaining lives.

#### 1. Results

This depreciation study developed average service life (ASL) estimates for all plant accounts with a composite of 44.4 years for Total Depreciable Gas Plant as shown on Schedule A.

The results shown in Schedule A, columns 8 and 17, also develop a composite for all depreciable gas plant of a 2.91% whole life rate and a 2.76% remaining life rate.

#### 2. Curve Types

The most commonly recognized curve type or frequency distribution is the "bell curve." Our depreciation study used a group of well recognized distributions known as the Iowa curves which were developed in the 1920s and 1930s at Iowa State University and are the most widely used and accepted curves in the industry for establishing survivor curves and average service life.

**National Grid NH**
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3. Net Salvage

The overall objective of depreciation is to recover the original cost investment less any salvage values plus the removal cost according to the various Uniform Systems of Accounts. The accrual rates proposed in this study reflect net salvage values based upon the most recent actual historical experience of the Company, modified by our judgment and experience. Our analyses determined less net salvage (more negative) than that authorized in the existing rates.

| | | | Whole Life | | |
|---|---|---|---|---|---|
| Plant Function | Balance at 12/31/06 $000 | Proposed Net Salvage Factor* | Accruals w/o Net Salvage ($000) | Accruals with Net Salvage ($000) | Remaining Life Accruals |
| Structures | 3,293 | 1.00 | 109.6 | 109.6 | 38.0 |
| Production | 8,994 | 1.00 | 299.4 | 299.4 | 79.8 |
| Trans. & Dist. | 240,747 | 1.35 | 4,984.8 | 6,740.2 | 6,797.1 |
| General | 9,176 | 0.96 | 514.7 | 493.7 | 318.1 |
| Total Depreciable Plant | 262,210 | 1.30 | 5,908.7 | 7,643.0 | 7,233.0 |

In order to provide additional information with respect to the cost of removal component included in the proposed Accrual Rates, Schedule A, columns (8) and (17), a separate calculation was undertaken to isolate the COR component with the results shown in column (18).

The following table summarizes our proposed depreciation results as presented on the attached depreciation schedule:

* Net salvage factor is unity (one) minus the estimated percent net salvage.

## National Grid NH
## Depreciation Accrual Rates Based on
## Gas Plant in Service at December 31, 2006

| Account | Description | Accrual Rate With Net Salvage (%) | Cost of Removal Component (%) |
|---|---|---|---|
| Structures | | | |
| 1308.1 | Production Plant Structures | 3.33 | 0.00 |
| 1308.6 | Distribution System Structures | 3.33 | 0.00 |
| 1308.7 | General and Miscellaneous Structures | 3.33 | 0.00 |
| Production Equipment | | | |
| 1330 | Other Production Equipment | 3.33 | 0.00 |
| Distribution Equipment | | | |
| 1356 | Mains | 1.92 | 0.25 |
| 1358 | Pumping and Regulating Equipment | 3.33 | 0.00 |
| 1359 | Services | 4.25 | 1.75 |
| 1360 | Customers' Meters and Installations | 2.86 | 0.00 |
| General Equipment | | | |
| 1372.1 | Office Equipment | 5.28 | 0.00 |
| 1374 | Stores Equipment | 3.33 | 0.00 |
| 1376 | Laboratory Equipment | 6.25 | 0.00 |
| 1377 | General Tools and Implements | 5.26 | 0.00 |
| 1378 | Communication Equipment | 6.67 | 0.00 |
| 1379 | Miscellaneous General Equipment | 6.67 | 0.00 |

## B. RECOMMENDATIONS

Based on our results of analyzing the Company's depreciable property, we recommend the following:

1. The Company request approval of the accrual rates shown in column (8) of the accrual rate Schedule A included in this report.

2. Future reviews of these accrual rates should be undertaken on a periodic basis.

**National Grid NH**
**Depreciation Accrual Rates Based on**
**Gas Plant in Service at December 31, 2006**

# III. INTRODUCTION

**National Grid NH**
**Depreciation Accrual Rates Based on**
**Gas Plant in Service at December 31, 2006**

# III. INTRODUCTION

## A. STUDY AUTHORIZATION

In the fourth quarter of 2007, Management Applications Consulting, Inc. (MAC), of Reading, Pennsylvania was authorized to conduct a depreciation rate study of National Grid NH's gas utility properties.

The study included detailed analyses of the depreciable gas plant in service at December 31, 2006 for the purpose of recommending depreciation accrual rates reflective of current facts and projections. The techniques used were those generally recognized and accepted in the industry and included analyses of historical plant investment experience and of the Company's forecasts of expected capital, as well as reviews of recent available cost of removal (COR) and salvage experience.

## B. DEFINITION OF DEPRECIATION

The overall objective of depreciation is to provide an orderly recovery of capital investment in depreciable property in a systematic and rational manner over a life term that assures full recovery of that investment. Regulatory accounting also provides for the amortization of any costs of removal expected to be incurred less anticipated salvage, i.e., net salvage, at the time the property is finally retired or removed from service by incorporating net salvage adjustments into the annual depreciation accrual rates. This approach ensures that these costs will be properly recovered by those using the facilities over the useful service life of an asset.

There are several definitions of depreciation. The definitions promulgated by the Federal Energy Regulatory Commission (FERC) and the National Association of Regulatory Utility Commissioners (NARUC) are essentially identical. Following is the NARUC definition:

> *"Depreciation", as applied to depreciable electric (gas) plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric (gas) plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the*

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*art, changes in demand and requirements of public authorities (and, in the case of natural gas companies, the exhaustion of natural resources).*

## C. GENERAL APPROACH TO CONDUCTING DEPRECIATION STUDIES

The MAC depreciation study analyses are consistent with the generally accepted approaches employed in the industry to determine appropriate annual depreciation accrual rates. In addition to reviewing and analyzing historical accounting records, engineering judgment is used in assessing historical experience as a possible factor to consider into the future. To this end, MAC becomes familiar with the property and its operations via site inspections and discussions with appropriate management personnel as to past practices and experience, as well as future plans and expectations, which could have had or may yet affect mortality patterns, average service lives, cost of removal or salvage. These approaches to preparing a depreciation study are typical of the industry.

## D. DEPRECIATION SYSTEM

Our depreciation system for this study consisted of using a straight line, broad group, average whole life depreciation method which uses the same accrual factor each year over the service life of the various plant accounts and subaccounts being analyzed. Due to the existence of very large quantities of assets, utility plant is generally grouped into broad groups of plant accounts and subaccounts in which the unit of measure is the original cost dollar, as opposed to individual property units.

Finally, depreciable plant must be recovered over a defined period of time, and our depreciation model used the whole life technique for calculating the annual accrual rates proposed. These rates are derived by using an estimated service life and include the calculated net salvage for each plant account:

$$\text{Whole Life Accrual Rate} = \frac{100\% - \text{Net Salvage}}{\text{Average Service Life}}$$

The account-by-account results are presented in the attached Schedule of Depreciation in column (4) without any net salvage and column (8) with the net savage factored into the proposed accrual rate.

# IV. DEVELOPMENT OF DEPRECIATION STUDY

**National Grid NH**
**Depreciation Accrual Rates Based on**
**Gas Plant in Service at December 31, 2006**

## IV. DEVELOPMENT OF DEPRECIATION STUDY

### A. DATABASE

The starting point of our depreciation study is the development of a database which utilizes the Company's additions, retirements, adjustments, transfers and plant balances by depreciable account and subaccount. Our analyses varied by account in order to develop appropriate databases from which to prepare our study based on available data.

### B. ANALYSIS OF HISTORY

The historical life analysis employed in this study was the Simulated Plant Record – Balances (SPR_BAL). The SPR-BAL analysis was introduced in 1947 by Mr. Alex Bauhan of Public Service Electric and Gas and is widely used and accepted in the industry.

The analyses are trial-and-error procedures in which the survivor statistics for various empirical (usually Iowa) curves are applied to the actual annual addition amounts to generate simulated year-end balances which are then compared to actual year-end balances. The best-fitting life is found for each curve type, and the curve-life combinations are ranked according to the sum of the squared differences between actual and simulated balances. In the procedure, there are three key statistical reliability indications developed for each curve-life combination. They are: the conformance index (CI), which is mathematically interrelated to the sum of the squared differences between the book and simulated balances; the retirement index (RI); and the cycle index. The retirement index is the percent retired from the oldest addition with the given indicated curve-life combination. The cycle index is the age of the oldest addition as a percent of the maximum probable life of the given curve-life combination. Maximum Probable Life (MPL) is the age at which the survivor curve drops to zero surviving. With a standard bell/symmetrical curve, the MPL is twice the average service life.

Life analyses of history, such as the SPR analyses, represent only part of the input that must be reviewed in arriving at the final recommended service life.

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C. SALVAGE, COST OF REMOVAL AND NET SALVAGE ANALYSIS

The Company provided historical gross salvage and removal cost information by plant account for the 2000 through 2006 period which was reviewed and applied to only these plant accounts. The Company's actual recorded salvage and removal costs were related to the retirements to develop annual and dollar-weighted, multi-year composite net salvage percentage values.

Our review of the data shows very little gross salvage associated with Distribution Plant retirements, i.e., net salvage is primarily net removal cost as shown below:

Net Salvage (NS) = Gross Salvage (GS) – Cost of Removal (COR)

Recent experience has shown that the cost of removal has generally been far greater in magnitude than gross salvage resulting in a negative net salvage which can vary significantly by account.

The inclusion of net salvage in determining the annual accrual rate for each account is a well recognized and appropriate calculation. Recognizing the uniqueness of each account's COR history in arriving at the final accrual coupled with the corresponding plant balances properly synchronizes and weights the results. This approach ensures that the cost of net salvage is recovered from those generations of customers benefiting from the asset over its service life. Our proposed net salvage and cost of removal are shown in the attached Schedule A.

The Company's available historical net salvage is but one input considered, along with our experience and judgment, in arriving at our final net salvage factors. For National Grid, our review resulted in the following recommendations:

| | | ---- Net Salvage ---- | |
|---|---|---|---|
| Description | Account | Proposed | Existing |
| Mains | 356 | -15% | -10% |
| Services | 359 | -70% | -60% |
| Office Equipment | 372.1 | + 5% | + 5% |

Zero net salvage is proposed for all other plant in this study as it was in the prior study.

# V. DISCUSSION OF RESULTS

**National Grid NH**
**Depreciation Accrual Rates Based on**
**Gas Plant in Service at December 31, 2006**

## V. DISCUSSION OF RESULTS

### A. BACKGROUND

The development of appropriate book depreciation accrual rates is a subjective process in which the primary task is life estimation. Many believe that life analysis is the primary point; certainly one should collect property history and analyze this information to identify whatever "evidence" can be gleaned therefrom, but life estimation is not life analysis.

One must recognize weaknesses and peculiarities in the life analysis employed, be generally aware of the equipment in the group being analyzed, be aware of the industry estimates for like equipment, and make every effort to obtain qualitative, first hand input relative to the particular company and equipment under study.

In connection with the latter point, we have solicited from National Grid personnel their input as to their upgrade/replacement plans, projections, and any circumstances which have or might yet impact upon the elements of depreciation rates. We have also made property inspections to familiarize ourselves with the equipment, the system, and the environment in which it functions. We visited the facilities, looked at their outward physical appearance and discussed them with our "tour guide(s)". The purpose of the inspections was to familiarize us with the equipment and the environment in which it functions and to observe housekeeping, maintenance and construction practices.

Property inspections give us an opportunity to discuss with our tour guides the facilities history and expected future, a sort of facilities conference on-the-go. Furthermore, in some regulatory jurisdictions a depreciation rate study done without an inspection tour is termed a "paper study" and is not readily accepted. It is our professional opinion that an inspection tour is cost effective and a necessary step in a proper depreciation rate study.

### B. APPLICATION OF COST RECOVERY

The whole life accrual rate is a function of two variables: the estimated net salvage (salvage less cost to retire) and the average service life of the group. The continued use of accrual rates properly developed at one point in time as a function of all circumstances known and projected at that time can be assumed to be appropriate for a limited number of years; however, if the lives and net salvage are not re-estimated periodically, the rates may not provide the appropriate recovery of capital.

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The primary reason for periodic reviews is that utility property is not as static as one might think. The equipment, technology, life expectations, mortality characteristics, salvage and removal costs, and demands of the public all change. Also, the Company may institute new or revised accounting policies or procedures or they may change operations in some way, all of which may impact the average lives of the dollars. As mentioned previously, our unit of measure is the dollar; we develop average dollar life estimates—not the estimated life of poles or meters, per se. Periodic studies should be undertaken to detect such changes and to reflect them in forward-looking depreciation accrual rates.

Obviously, when a change in either net salvage or life expectations is observed, the book depreciation reserve compared to the computed or theoretical reserve immediately appears as either over or under accrued. Realistic trends in either the service life or net salvage cannot generally be discerned on an annual basis; therefore, if such changes begin to occur immediately upon completion of a depreciation rate study, the effect of the change will not be fully observed and reflected in revised accrual rates until the next study is performed.

In general, the variance in the reserve is simply the theoretical reserve based on an updated set of factors as developed in a depreciation study and the existing book reserves which reflect the historical reserve adjustments previously approved. The theoretical reserve calculation, however, is based on a new set of accrual rates, and applying these results to the current plant balances as if they were constant historical factors will result in a variance. Obviously, there will usually be changes in depreciation rates followed by changes in theoretical reserves and resulting variances.

One reasonable method to eliminate this difference (variance) between the book and theoretical depreciation reserve is to amortize the variance over some reasonable time period, as previously mentioned. By this we mean one computes the annual deprecation accrual in the normal manner and each year adds to or subtracts from that normal accrual an amortization amount, derived as described previously.

Opponents of the use of a remaining life accrual rate are concerned that the amortization of the reserve variance which is implicit in the remaining life rate method may occur too rapidly when the rate is applied to plant balances, especially if those balances are increasing rapidly. The use of a whole life accrual rate with (plus or minus) an annual amortization amount can correctly eliminate such concerns and can be easily accomplished.

For some categories of property, particularly mass properties, statistical mortality studies of past retirement experience may provide historical indications of the dispersion of

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retirements and of average service life, if there has been sufficient retirement activity over a reasonable period of time. Such information may provide some indication as to what to expect in the future; however, it should not be taken for granted that the future will mirror the past, especially when present policies, plans, or external circumstances indicate otherwise. For example, if a Company eliminates its sizable meter repair/rebuild operations, such a change will likely result in a shorter average service life for meters. In such instances, as well as when reliable retirement experience is lacking, reliance must be placed upon informed judgment in the establishment of expected average service lives and accrual rates.

## C. AVERAGE SERVICE LIFE AND SURVIVOR CURVES

Survivor curves are graphical representations of the surviving property for each age for the life of a group of assets, such as a plant account. The survivor curve selection from analyses of the Company's database for each account then establishes the average and remaining life for that group. These survivor curve characteristics are generally best reflected for utility property by the use of a well established system of generalized survivor curves known in the industry as Iowa curves. Each curve can be identified by two components in our study. For instance, for Account 356, Mains, our recommended curve is the 60-year R 1.0. The 60 represents the average service life, and the other component is the shape of the curve. A brief comment here is that an "L" designation indicates skewness to earlier retirements while an "R" designation indicates skewness towards later retirements, the point of reference being the average service life, the mode of the curve.

For some accounts, such as Office Equipment (372.1), we recommended an "S" type which is a symmetrical curve and indicates that the greatest frequency of retirements occurs at the average service life. Finally, the number following the letter for each curve represents the height of each curve with the higher values representing a reduced range and maximum life.

Historical average service life (ASL) indications were developed using the Simulated Plant Record – Balance (SPR-BAL) method for the life analyses of National Grid's depreciable group assets as recorded and identified by accounts and subaccounts. Our final recommendations for each account were based on many factors which considered input from Company personnel, property inspections of the facilities along with our experience and judgment of similar properties as has been discussed throughout this report.

## National Grid NH
## Depreciation Accrual Rates Based on
## Gas Plant in Service at December 31, 2006

The following table lists the ASL and curve type selected for each account based on our analyses:

| Account | Description | ASL | Curve Type |
|---|---|---|---|
| Structures | | | |
| 1308.1 | Production Plant Structures | 30.0 | R 1.0 |
| 1308.6 | Distribution System Structures | 30.0 | R 1.0 |
| 1308.7 | General and Miscellaneous Structures | 30.0 | R 1.0 |
| Production Equipment | | | |
| 1330 | Other Production Equipment | 30.0 | R 1.0 |
| Distribution Equipment | | | |
| 1356 | Mains | 60.0 | R 1.0 |
| 1358 | Pumping and Regulating Equipment | 30.0 | S 0.0 |
| 1359 | Services | 40.0 | R 4.0 |
| 1360 | Customers' Meters and Installations | 35.0 | R 2.5 |
| General Equipment | | | |
| 1372.1 | Office Equipment | 18.0 | S 4.0 |
| 1374 | Stores Equipment | 30.0 | SQ |
| 1376 | Laboratory Equipment | 16.0 | S 5.0 |
| 1377 | General Tools and Implements | 19.0 | S 6.0 |
| 1378 | Communication Equipment | 15.0 | R 3.0 |
| 1379 | Miscellaneous General Equipment | 15.0 | S 5.0 |

**National Grid NH**
**Depreciation Accrual Rates Based on**
**Gas Plant in Service at December 31, 2006**

# VI. ACCRUAL RATE SCHEDULE AND DESCRIPTIONS

**National Grid NH**
**Depreciation Accrual Rates Based on**
**Gas Plant in Service at December 31, 2006**

# Schedule A

## Schedule of Depreciation Accrual Rates
## Whole Life Schedule
## with Amortization of Reserve Variance

ENERGY NORTH NATURAL GAS INC. D/B/A NATIONAL GRID NH

SCHEDULE A

SCHEDULE OF DEPRECIATION ACCRUAL RATES @12/31/06

WHOLE LIFE SCHEDULE WITH AMORTIZATION OF RESERVE VARIANCE

| ACCOUNT NUMBER | DESCRIPTION | PLANT BALANCE @12/31/06 | DISP TYPE | ASL | ACCRUAL RATE W/O NET SALV. | ACCRUAL WITHOUT NET SALV. | NET SALV. % | SALV. FACTOR | ACCRUAL RATE W/ NET SALV. | ACCRUAL WITH NET SALV. | THEO. RSV. WITHOUT NET SALV. | THEO. RSV. WITH NET SALV. | ALLOC. BOOK RSV. @12/31/06 | RESERVE VARIANCE | ARL | AMORT. OF RESERVE VARIANCE | ACCRUAL WITH AMORT. | ACCRUAL RATE W/ AMORT. | COR RATE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) |
| | STRUCTURES | | | | | | | | | | | | | | | | | | |
| 1308.1 | PRODUCTION PLANT STRUCTURES | 1,195,433 | R 1.0 | 30.0 | 3.33 | 39,808 | 0 | 1.00 | 3.33 | 39,808 | 570,236 | 570,236 | 998,174 | -427,938 | 15.7 | -27,257 | 12,551 | 1.05 | 0.00% |
| 1308.6 | DISTRIBUTION SYSTEM STRUCTURES | 544,322 | R 1.0 | 30.0 | 3.33 | 18,126 | 0 | 1.00 | 3.33 | 18,126 | 232,677 | 232,677 | 330,557 | -97,880 | 17.2 | -5,691 | 12,435 | 2.28 | 0.00% |
| 1308.7 | GENERAL AND MISCELLANEOUS STRUCTURES | 1,553,420 | R 1.0 | 30.0 | 3.33 | 51,729 | 0 | 1.00 | 3.33 | 51,729 | 667,464 | 667,464 | 1,328,897 | -661,433 | 17.1 | -38,680 | 13,049 | 0.84 | 0.00% |
| | TOTAL DEPREC. STRUCTURES | 3,293,175 | | 30.0 | 3.33 | 109,663 | | | 3.33 | 109,663 | 1,470,377 | 1,470,377 | 2,657,628 | -1,187,251 | | -71,628 | 38,035 | 1.15 | |
| | PRODUCTION EQUIPMENT | | | | | | | | | | | | | | | | | | |
| 1330 | OTHER PRODUCTION EQUIPMENT | 8,993,569 | R 1.0 | 30.0 | 3.33 | 299,486 | 0 | 1.00 | 3.33 | 299,486 | 4,280,025 | 4,280,025 | 7,729,462 | -3,449,437 | 15.7 | -219,709 | 79,777 | 0.89 | 0.00% |
| | DISTRIBUTION EQUIPMENT | | | | | | | | | | | | | | | | | | |
| 1356 | MAINS | 136,231,399 | R 1.0 | 60.0 | 1.67 | 2,275,064 | -15 | 1.15 | 1.92 | 2,616,643 | 22,025,280 | 26,019,079 | 38,926,629 | -12,907,550 | 50.0 | -258,151 | 2,357,492 | 1.73 | 0.25% |
| 1358 | PUMPING AND REGULATING EQUIPMENT | 2,473,039 | S 0.0 | 30.0 | 3.33 | 82,352 | 0 | 1.00 | 3.33 | 82,352 | 519,452 | 519,452 | 643,785 | -124,333 | 23.7 | -5,246 | 77,106 | 3.12 | 0.00% |
| 1359 | SERVICES | 80,850,399 | R 4.0 | 40.0 | 2.50 | 2,021,260 | -70 | 1.70 | 4.25 | 3,436,142 | 22,397,617 | 38,075,949 | 22,789,274 | 15,286,675 | 28.9 | 528,951 | 3,965,093 | 4.90 | 1.75% |
| 1360 | CUSTOMERS' METERS AND INSTALLATIONS | 21,192,242 | R 2.5 | 35.0 | 2.86 | 606,098 | 0 | 1.00 | 2.86 | 606,098 | 5,168,818 | 5,168,818 | 10,698,386 | -5,529,568 | 26.5 | -208,663 | 397,435 | 1.88 | 0.00% |
| | TOTAL DEPREC. DISTRIBUTION EQUIPMENT | 240,747,070 | | 48.3 | 2.07 | 4,984,775 | | | 2.80 | 6,740,235 | 50,711,173 | 69,783,298 | 73,058,074 | -3,274,776 | | 56,891 | 6,797,126 | 2.82 | |
| | GENERAL EQUIPMENT | | | | | | | | | | | | | | | | | | |
| 1372.1 | OFFICE EQUIPMENT | 7,524,999 | S 4.0 | 18.0 | 5.56 | 418,390 | 5 | 0.95 | 5.28 | 397,320 | 1,632,803 | 1,551,163 | 3,348,598 | -1,797,435 | 14.1 | -127,478 | 269,842 | 3.59 | 0.00% |
| 1374 | STORES EQUIPMENT | 43,120 | SQ | 30.0 | 3.33 | 1,436 | 0 | 1.00 | 3.33 | 1,436 | 10,135 | 10,135 | 36,851 | -26,716 | 22.9 | -1,167 | 269 | 0.62 | 0.00% |
| 1376 | LABORATORY EQUIPMENT | 368,637 | S 5.0 | 16.0 | 6.25 | 23,040 | 0 | 1.00 | 6.25 | 23,040 | 211,157 | 211,157 | 368,637 | | FULLY DEPRECIATED | | | | |
| 1377 | GENERAL TOOLS AND IMPLEMENTS | 767,601 | S 6.0 | 19.0 | 5.26 | 40,376 | 0 | 1.00 | 5.26 | 40,376 | 262,437 | 262,437 | 390,288 | -127,851 | 12.5 | -10,228 | 30,148 | 3.93 | 0.00% |
| 1378 | COMMUNICATION EQUIPMENT | 364,039 | R 3.0 | 15.0 | 6.67 | 24,321 | 0 | 1.00 | 6.67 | 24,321 | 81,319 | 81,319 | 171,101 | -89,782 | 11.7 | -7,674 | 16,647 | 4.57 | 0.00% |
| 1379 | MISCELLANEOUS GENERAL EQUIPMENT | 107,350 | S 5.0 | 15.0 | 6.67 | 7,161 | 0 | 1.00 | 6.67 | 7,161 | 45,922 | 45,922 | 96,953 | -51,031 | 8.6 | -5,934 | 1,227 | 1.14 | 0.00% |
| | TOTAL DEPREC. GENERAL EQUIPMENT | 9,170,359 | | 17.8 | 5.61 | 514,724 | | | 5.38 | 493,054 | 2,243,773 | 2,162,133 | 4,412,428 | -2,092,815 | | -152,481 | 318,133 | 3.47 | |
| | TOTAL DEPREC. GAS PLANT | 262,210,178 | | 44.4 | 2.25 | 5,908,647 | | | 2.91 | 7,643,037 | 58,705,348 | 77,095,833 | 87,857,592 | -10,004,279 | | -386,927 | 7,233,071 | 2.76 | |
| | LAND | 608,402 | | | | | | | | | | | | | | | | | |
| | OFI STRUCTURES RETAINED | 0 | | | | | | | | | | | 105,109 | | | | | | |
| 1373 | TRANSPORTATION EQUIPMENT | 587,017 | | | | | | | | | | | 698,424 | | | | | | |
| 1395 | UNFINISHED CONSTRUCTION | 9,472,009 | | | | | | | | | | | | | | | | | |
| 1080K | ARO | | | | | | | | | | | | -694,277 | | | | | | |
| 1113K | | | | | | | | | | | | | -2,511,368 | | | | | | |
| 1220K | | | | | | | | | | | | | -105,109 | | | | | | |
| 1091K | | | | | | | | | | | | | 117,481 | | | | | | |
| 110AR | | | | | | | | | | | | | 459,391 | | | | | | |
| | TOTAL GAS PLANT IN SERVICE | 272,877,604 | | | | | | | | | | | 85,937,243 | | | | | | |

## WHOLE LIFE SCHEDULE WITH AMORTIZATION OF RESERVE VARIANCE

## EXPLANATORY NOTES

The Schedule includes indicated (theoretical) reserves both with and without net salvage, the allocation of the book reserve, and the reserve variance. It also shows the development of the remaining life accruals, in that the remaining life accrual is made up of two components, the normal whole life accrual plus the amortization of any reserve variance.

The following is an explanation of each column of the Schedule:

1. Column (1) presents the book balance for each account or sub-account at the indicated date.

2. Column (2) labeled "DISP TYPE" is designated as either Forecast or some selected Iowa curve type as discussed in the text.

3. Column (3) indicates the direct weighted average dollar service life in years for each investment group.

4. Column (4) is the unadjusted whole life accrual rate developed by dividing unity by Column (3), and expressing the quotient as a percentage.

5. Column (5) is the whole life accrual with no salvage adjustment, based upon the average service life associated with each investment group. These accruals are developed by multiplying Column (1) by Column (4).

6. Column (6) is the percent net salvage expectation; net salvage equals gross salvage minus removal cost.

7. Column (7) is the salvage factor, derived by subtracting the (signed) net salvage ratio from unity; e.g., a salvage factor of 1.10 is the result of 1.00 minus an expected net salvage ratio of minus 0.10; i.e., 1.00 - (-0.10) = 1.10.

8. Column (8) is the whole life accrual rate, reflecting adjustment for net salvage expectations; it is developed by multiplying Column (4) by Column (7), and expressing the product as a percentage.

9. Column (9) is the whole life accrual, adjusted for net salvage expectations. It is developed by multiplying Column (8) by Column (1).

**WHOLE LIFE SCHEDULE WITH AMORTIZATION OF RESERVE VARIANCE**

**EXPLANATORY NOTES**

10. Column (10) shows indicated depreciation reserves, unadjusted for net salvage expectations, calculated on the basis of the average service life and dispersion characteristics (or forecasts) associated with each investment group.

11. Column (11) is the indicated depreciation reserve, adjusted for net salvage expectations by multiplying Column (10) by Column (7).

12. Column (12) "ALLOC. BOOK RSV. @12/31/06" contains book reserves allocated to accounts, or sub-accounts from the functional book reserve level on the basis of the adjusted indicated reserves in Column (11). If book reserves are known and maintained at a finer level, or only at a larger level, these figures are used or allocated as appropriate.

13. Column (13) shows the difference between adjusted indicated reserves (Column 11) and allocated book reserves (Column 12); i.e., Column (11) minus Column (12).

14. Column (14), "ARL" (Average Dollar Remaining Life) contains the weighted average dollar remaining life. Average remaining life composites for two or more investment groups are derived by dividing unadjusted net plant (Column 1 minus Column 10) by the unadjusted whole life accrual (Column 5).

15. Column (15), "AMORT. OF RESERVE VARIANCE", shows the result of dividing the indicated reserve variance in Column (13) by the estimated remaining life in Column (14).

16. Column (16), "ACCRUAL WITH AMORT," is the sum of the whole life accrual in Column (9) and the indicated reserve variance accrual in Column (15).

17. Column (17), "ACCRUAL RATE W/AMORT," is the result of Column (16) divided by Column (1), with the quotient multiplied by 100 to convert to percentage.

18 The column labeled "COR RATE" is the cost of removal percent that is included in the accrual rate with net salvage.

# STATE OF NEW HAMPSHIRE
# BEFORE THE
# PUBLIC UTILITIES COMMISSION

**EnergyNorth Natural Gas, Inc.**
**d/b/a National Grid NH**

**DG 08-009**

**Direct Testimony**

**of**

**Paul R. Moul**
**Managing Consultant**
**P. Moul & Associates**

**Concerning**
**Cost of Capital**

**February 25, 2008**

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Page No.

| GLOSSARY OF ACRONYMS AND DEFINED TERMS | |
|---|---|
| **ACRONYM** | **DEFINED TERM** |
| AFUDC | Allowance for Funds Used During Construction |
| ß | Beta |
| b | represents the retention rate that consists of the fraction of earnings that are not paid out as dividends |
| b x r | Represents internal growth |
| CAPM | Capital Asset Pricing Model |
| CCR | Corporate Credit Rating |
| CE | Comparable Earnings |
| DCF | Discounted Cash Flow |
| FERC | Federal Energy Regulatory Commission |
| FFO | Funds from Operations |
| FOMC | Federal Open Market Committee |
| g | Growth rate |
| GCR | Gas Cost Rate |
| IGF | Internally Generated Funds |
| LDC | Local Distribution Companies |
| Lev | Leverage modification |
| LT | Long Term |
| M&A | Merger and Acquisition |
| MLP | Master Limited Partnerships |
| PUHCA | Public Utility Holding Company Act |
| r | represents the expected rate of return on common equity |
| Rf | Risk-free rate of return |
| Rm | Market risk premium |
| RP | Risk Premium |
| s | Represents the new common shares expected to be issued by a firm |
| s x v | Represents external growth |
| S&P | Standard & Poor's |
| v | Represents the value that accrues to existing shareholders from selling stock at a price different from book value |

## INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

**Q. Please state your name, occupation and business address.**

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant of the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Attachment PRM-1, which follows my direct testimony.

**Q. What is the purpose of your testimony?**

A. My testimony presents data, analysis, and a recommendation concerning the appropriate rate of return on common equity that should be used in the determination of the revenue requirement for EnergyNorth Natural Gas, Inc. d/b/a National Grid NH ("National Grid NH" or the "Company"). Additional evidence is contained in Attachments PRM-2 through PRM-10, which follow my direct testimony. The items covered in these attachments provide additional detailed information concerning the explanation and application of the various financial models upon which I rely. My analysis and recommendation are supported by the detailed financial data contained in Attachments PRM-11 through Attachment PRM-21.

**Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return on common equity for the Company in this case?**

A. My conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity of 11.50%.

**Q. Please provide an overview of the Company.**

A. The Company is an indirect wholly-owned subsidiary of National Grid USA. Natural Grid USA provides electric delivery service to approximately 5 million customers in Massachusetts, New Hampshire, New York, and Rhode Island;

natural gas distribution service to approximately 3.4 million customers in Massachusetts, New Hampshire, New York, and Rhode Island; and electric transmission in the New York and the New England region.

The Company provides natural gas distribution service to approximately 84,000 customers located in south-central and central regions of New Hampshire and in Berlin, NH. In 2006, approximately 39% of throughput was to residential customers, approximately 32% of throughput was to commercial customers, and approximately 29% of throughput was to industrial, large volume, interruptible and transportation customers. National Grid NH obtains its gas supplies from producers and marketers and has transportation arrangements through a connection with one interstate pipeline. The Company has arrangements for underground storage of natural gas and owns liquefied natural gas and propane facilities to supplement flowing gas.

**Q. How have you determined the cost of common equity in this case?**

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a natural gas utility, such as National Grid NH. In this regard, I relied on four (4) well-recognized measures of the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. My testimony describes each of the methods, the results of each method, and my conclusion regarding the appropriate cost of common equity based on a consideration of those methods.

I understand that the Commission has relied on the DCF model in the past, and hence I have addressed this method first in my testimony. However, I consider this method to have certain flaws and limitations, which indicate that exclusive reliance on it is inappropriate. My testimony will discuss the problems their tariff, and (vii) have at least 60% of their assets subject to utility regulation. The companies in the proxy group are identified on page 2 of Attachment PRM-12. I will refer to these companies as the "Gas Group" throughout my testimony.

**Q. How have you performed your cost of equity analysis with the market data for the Gas Group?**

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company has become increasingly problematic. By employing group average data, rather than individual company's analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

**Q. Please summarize your cost of equity analysis.**

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

| | Gas Group |
|---|---|
| DCF | 9.84% |
| RP | 11.44% |
| CAPM | 13.45% |
| Comparable Earnings | 13.90% |
| Average | 12.16% |
| Median | 12.45% |
| Mid-point | 11.87% |

Focusing upon the market model approaches (i.e., DCF, RP and CAPM) to estimating the cost of equity, the average equity return is 11.58% (9.84% + 11.44% + 13.45% = 34.73% ÷ 3). The market measures of the cost of equity have been emphasized because they reflect fundamentals present in the stock and bond markets, rather than the business cycle, which is the principal determinant of the Comparable Earnings approach. From these measures, I recommend that the Commission set the Company's rate of return on common equity at 11.50%.

## NATURAL GAS RISK FACTORS

**Q. What factors currently affect the business risk of natural gas utilities?**

A. The competitive, regulatory and economic risks facing gas utilities are different today than formerly. Market-oriented pricing, open access for gas transportation, and changes in service agreements mean that natural gas utilities have been operating in a more complex environment with time frames for decision-making considerably shortened. Of particular concern for the Company, the recent high prices and volatility in natural gas commodity prices has had a negative impact on its customers, and has resulted in declines in average use per existing customer. Higher commodity prices mean higher customer bills, as the cost of delivered gas is recovered through the GCR mechanism. With higher gas costs, the likelihood of more intense regulatory scrutiny exists and the risk of disallowances is increased. Since there is no opportunity to earn a profit on the cost of gas, the risks associated with gas procurement are especially acute when commodity costs are high. Higher and volatile gas costs may also result in further declines in average use per existing customer and in fewer new customers selecting natural gas to meet their energy needs.

As the competitiveness of the natural gas business increases, the risk also increases. With the availability of customer-owned transportation gas, along with delivery of uncertain volumes to dual-fuel customers, risk will continue to be elevated as large end-users obtain for themselves the range of unbundled service offerings which are currently available from the interstate pipelines for the local distribution utilities.

**Q. Does the Company face competition in its natural gas business?**

A. Yes. The changes fostered by the Federal Energy Regulatory Commission's Order 636 have promoted competition among and between pipelines and distributors through bypass facilities and placed more responsibilities on local distribution companies, such as National Grid NH, to manage the upstream acquisition and delivery functions both from a reliability and price perspective. While larger customers have made their own gas supply arrangements, the customers that remain sales customers tend to be lower load factor customers that tend to be more expensive to serve.

**Q. How does the Company's throughput to large volume users affect its risk profile?**

A. The Company's risk profile is influenced by natural gas sold/delivered to its thirteen largest customers, which represent 22 million decatherms of throughput. Large volume users, which have traditionally used transportation service, have the ability to bypass the LDC system. Indeed, the Company has identified four of these customers that represent a potential for bypass. Success in this aspect of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from competitors. Moreover, external factors can also influence the Company's throughput to these customers because cost factors can impact their operations relative to alternative facilities located outside the Company's service territory.

**Q. Please indicate how its construction program affects the Company's risk profile.**

A. The Company is required to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The rehabilitation of the Company's infrastructure represents a non-revenue producing use of capital. The Company had 179 miles (or approximately 14%) of its distribution mains constructed of cast iron and unprotected steel pipe as of year-end 2006. Also, the Company has 10,316 (or approximately 16%) of its services constructed of unprotected steel and cast iron. The Company projects its construction expenditures will be approximately $135 million in the period 2007-2011. Of that amount, the Company expects to internally generate about 50% of its construction expenditures before the payment of dividends.

**Q. How should the Commission respond to the issues facing the natural gas utilities and in particular National Grid NH?**

A. The Commission should recognize and take into account the heightened competitive environment and the risk it poses in the natural gas business in determining the cost of capital for the Company, and provide a reasonable opportunity for the Company to actually achieve its cost of capital. It should also recognize that the Company is subject to risk related to earnings attrition and regulatory lag, since its ongoing costs are susceptible to inflation.

## FUNDAMENTAL RISK ANALYSIS

**Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for determining a utility's cost of equity?**

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns are described in Attachment PRM-3. For this purpose, I compared the Company to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group.

**Q. What are the components of the S&P Public Utilities?**

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Attachment PRM-13.

**Q. What criteria did you employ to assemble the Gas Group?**

A. I set forth the criteria that I employed to assemble the Gas Group above and will not repeat it here.

**Q. Why have you imposed a selection criterion that includes a percentage of gas assets?**

A. In order to align the cost of equity determination to the gas business, I have employed screening criteria that impose a limitation on the non-gas businesses of the proxy companies. In this regard, there are three principal financial variables that could be employed to measure the role of non-gas business of a firm. These are: revenues, operating income, and assets employed. I imposed a screening criterion whereby 60% of a company's assets must be devoted to the gas business to be included in the Gas Group.

I did not use revenues for this purpose because the margins on other business segments are generally dissimilar to the gas distribution business. Energy trading is a case in point, which would make revenue comparisons incompatible because of the small margins associated with this business segment.

I also did not use operating income for this purpose because of the margin issue discussed above. In addition, some non-regulated business segments may incur losses due to start-up, or other reasons, that can distort the percentage calculations.

I did use an asset screening criteria (the percentage of gas assets) because it best describes the amount of capital that a firm devotes to each business segment. It is the potential return on that capital that represents the primary focus of investors when they value the securities of a firm.

The Gas Group has the following percentage of its operations from the gas utility business: revenues 70%, income 69%, and assets 86%. These determinations were made to the extent that information was revealed in each company's 2006 annual report.

**Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?**

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

**Q. How do the bond ratings compare for the Company, the Gas Group, and the S&P Public Utilities?**

A. The Company does not have a bond rating because it has no debt that is held by outside investors. The corporate credit rating ("CCR") for National Grid USA is A- from Standard and Poor's Corporation ("S&P"), and the Long Term ("LT") issuer rating is A3 from Moody's Investors Services ("Moody's"). The CCR designation by S&P and LT issuer rating by Moody's focus upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The average credit quality of the Gas Group is an A from S&P and A3 from Moody's. For the S&P Public Utilities, the average composite rating is BBB+ by S&P and Baa1 by Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

**Q. How do the financial data compare for National Grid NH, the Gas Group, and the S&P Public Utilities?**

A. The broad categories of financial data that I will discuss are shown on Attachments PRM-11, PRM-12, and PRM-13. The data cover the five-year period 2002-2006. I should note that I have removed the goodwill recorded on the Company's balance sheet from the common equity account for the purpose of my analysis shown on Attachment PRM-11. The important categories of relative risk may be summarized as follows:

<u>Size.</u> In terms of capitalization, National Grid NH is smaller than the average size of the Gas Group, and very much smaller than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier

than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for the Gas Group and National Grid NH.

Market Ratios. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[1]

There are no market ratios available for the Company because National Grid USA owns its stock. The five-year average price-earnings multiple for the Gas Group was fairly similar to that of the S&P Public Utilities. The five-year average dividend yields were somewhat higher for the Gas Group as compared to the S&P Public Utilities. The average market-to-book ratios were somewhat higher for the Gas Group than the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 56.9% for National Grid

[1] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

NH, 52.4% for the Gas Group, and 41.2% for the S&P Public Utilities. For this case, as explained in the testimony of Mr. O'Shaughnessy, the Company's common equity ratio that will be used in the weighted average cost of capital calculation is 50%.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.424 (2.8% ÷ 6.6%) for National Grid NH, 0.058 (0.7% ÷ 12.1%) for the Gas Group, and 0.159 (1.7% ÷ 10.7%) for the S&P Public Utilities. National Grid NH has greater risk due to its higher earnings variability as compared to the Gas Group.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[2] The five-year average operating ratios were 90.2% for National Grid NH, 87.6% for the Gas Group, and 84.0% for the S&P Public Utilities.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")) was 2.61 times for National Grid NH, 4.20 times for the Gas Group, and 2.89 times for the S&P Public Utilities.

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2 The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for National Grid NH, the Gas Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 99.4% for National Grid NH, 92.1% for the Gas Group, and 110.1% for the S&P Public Utilities.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[3] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of .86 as the average for the Gas Group (see page 2 of Attachment PRM-12), and .95 as the average for the S&P Public Utilities (see page 3 of Attachment PRM-13).

**Q. Please summarize your risk evaluation.**

A. The risk of National Grid NH parallels that of the Gas Group in certain respects. In

[3] The procedure used to calculate the beta coefficient published by Value Line is described in Attachment PRM-9. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

## DISCOUNTED CASH FLOW ANALYSIS

**Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.**

A. As noted above, I used the DCF method as one indicator of the cost of equity to be taken into consideration with other methods. The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Attachment PRM-5. I will summarize them here. The Discounted Cash Flow ("DCF") model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stocks consists of a current cash (dividend) yield and future price appreciation (growth) of the investment.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

As I describe in Attachment PRM-5, the DCF approach has other limitations that diminish its usefulness in the ratesetting process when the market capitalization diverges significantly from the book value capitalization. When this situation exists, as it does here, the unadjusted DCF method will lead to a misspecified cost of equity when it is applied to a book value capital structure. Therefore, the DCF method must include an adjustment to account for this variance.

**Q. Please explain the dividend yield component of a DCF analysis.**

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended December 2007, the monthly dividend yields of the Gas Group are shown graphically on Attachment PRM-14. The monthly dividend yields shown on Attachment PRM-14 reflect an adjustment to the month-end prices to reflect the build up of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment). An explanation of this adjustment is provided in Attachment PRM-5.

For the twelve months ending December 2007, the average dividend yield was 3.67% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three- month periods was 3.77% for both periods. I have used, for the purpose of my direct testimony, a dividend yield of 3.77% for the Gas Group, which represents the six-month average yield.

For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments i.e., the higher expected dividends for the future, because the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners, and used the average of the three adjusted values as calculated in Attachment PRM-5. That adjusted dividend yield is 3.86% for the Gas Group.

**Q. Please explain the underlying factors that influence investors' growth expectations.**

A. As noted previously, investors are interested principally in the future growth of their investment (i.e., the price per share of the stock). As I explain in Attachment PRM-

5, future earnings per share growth represents their primary focus because under the constant price-earnings multiple assumption of the DCF model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth. The variables that can be considered include: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors.

A fundamental growth rate analysis also can be formulated, which consists of internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. The internal growth rate can be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time. Hence, a fundamental growth rate analysis is duplicative of expected book value per share growth.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated during the life of a business. That is to say, the growth of a firm may ramp-up and ramp-down in cycles over time.

**Q. What investor-expected growth rate is appropriate in a DCF calculation?**

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor expected growth.

**Q. What company-specific data have you considered in your growth rate analysis?**

A. I have considered the growth in the financial variables shown on Attachment PRM-15 and 16. The bar graph provided on Attachment PRM-15 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Attachment PRM-15, historical growth in earnings per share was in the range of 5.50% to

8.07% for the Gas Group.

Attachment PRM-16 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, and Reuters/Market Guide and from the Value Line publication. IBES/First Call, Zacks, and Reuters/Market Guide represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and Reuters/Market Guide forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Attachment PRM-16 for the Gas Group.

Although five-year forecasts usually receive the most attention in the growth analysis for DCF purposes, present market performance has been strongly influenced by short-term earnings forecasts. Each of the major publications provides earnings forecasts for the current and subsequent year. These short-term earnings forecasts receive prominent coverage, and indeed they dominate these publications. While the DCF model typically focuses upon long-run estimates of earnings, stock prices are clearly influenced by current and near-term earnings forecasts.

**Q. What specific evidence have you considered in the DCF growth analysis?**

A. As to the five-year forecast growth rates, Attachment PRM-16 indicates that the projected earnings per share growth rates for the Gas Group are 5.18% by IBES/First Call, 5.50% by Zacks, 5.24% by Reuters/Market Guide, and 5.03% by Value Line. The Value Line projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 5.03%) than the dividends per share (i.e., 4.29%), which indicates a declining dividend payout ratio for the future. As indicated earlier, and in Attachment PRM-5, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

**Q. What conclusion have you drawn from these data?**

A. Ideally historical and projected earnings per share and dividends per share growth indicators would be used to provide an assessment of investor growth expectations for a firm; however, the circumstances of the Gas Group mandate that the greater emphasis be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is forecasts of earnings per share growth.[4] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Reuters/Market Guide, and Value Line, represent a reasonable assessment of investor expectations.

It is appropriate to consider all forecasts of earnings growth rates that are available to investors. In this regard, I have considered the forecasts from IBES/First Call, Zacks, Reuters/Market Guide and Value Line. The IBES/First Call, Zacks, and Reuters/Market Guide growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, and Reuters/Market Guide estimates are obtained from the Internet and are widely available to investors free-of-charge. First Call is probably quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries.

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4 "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, spring 1989 by Gordon, Gordon & Gould.

The forecasts of earnings per share growth, as shown on Attachment PRM-16 provide a range of growth rates of 5.03% to 5.50%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.25% is within the array of earnings per share growth rates shown by the analysts' forecasts.

**Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?**

A. Only if the capital structure ratios are measured with the market value of debt and equity. If book values are used to compute the capital structure ratios, then an adjustment is required.

**Q. Please explain why.**

A. If regulators rely upon the results of the DCF (which are based on the market price of the stock of the companies analyzed) and those results are used in computing the weighted average cost of capital with a book value capital structure, those results will not reflect the degree of financial risk associated with the capital structure shown by the market capitalization. When the price diverges from book value, the potential exists for a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value.

This shortcoming of the DCF has persuaded one regulatory agency to adjust the cost of equity upward to make the return consistent with the book value capital structure. Provisions for this risk difference were made by the Pennsylvania Public Utility Commission in the following cases:

- January 10, 2002 for Pennsylvania-American Water Company in Docket No. R-00016339 -- 60 basis points adjustment.
- August 1, 2002 for Philadelphia Suburban Water Company in Docket No. R-

00016750 -- 80 basis points adjustment.

- January 29, 2004 for Pennsylvania-American Water Company in Docket No. R-00038304 (affirmed by the Commonwealth Court on November 8, 2004) -- 60 basis points adjustment.
- August 5, 2004 for Aqua Pennsylvania, Inc. in Docket No. R-00038805 -- 60 basis points adjustment.
- December 22, 2004 for PPL Electric Utilities Corporation in Docket No. R-00049255 -- 45 basis points.
- February 8, 2007 for PPL Gas Utilities Corporation in Docket No. R-00061398 -- 70 basis points adjustment.

It must be recognized that in order to make the DCF results relevant to a utility's capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate cannot be used without modification. As I will explain later in my testimony, the results of the DCF model must be modified to account for differences in risk when the book value capital structure contains more financial leverage than the market value capital structure.

**Q. Is your leverage adjustment to the DCF model dependent upon the market valuation or book valuation from an investor's perspective?**

A. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The DCF formula is derived from the standard valuation model: P = D/ (k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P+g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the ratesetting process utilizes the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Since the ratesetting process uses a different set of ratios calculated from the book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus a term(s) reflecting the increase in financial risk resulting from the use of leverage in the capital structure. Multiple terms are used in the case of both debt and preferred stock. The resulting return is the one that is necessary for the utility to earn on its own book value capital structure to reflect the financial risk that varies from the return that applies to the market value capital structure.

**Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?**

A. No. The leverage adjustment I use is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book are not on point. The leverage adjustment I use deals with the issue of financial risk and is not intended to transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure. This is the foundation of the principal that capital structure influences the cost of equity.

Further, as noted previously, the high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on equity that differs from their respective costs of equity. Stock prices above book value are common for utility stocks, and indeed non-regulated stock prices exceed book values by even greater margins. In this regard, according to the Barron's issue of January 7, 2008, the major market indices' market-to-book ratios are well above unity. Utility stocks trade at a multiple of 2.75 times book value which is below the market multiple of other indices. For example, the S&P 500 index trades at 2.80 times book value, the S&P Industrial index is at 3.46 times book value, and the Dow Jones Industrial index is at 3.85 times book value. It is highly doubtful that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true that when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

**Q. What are the implications of a DCF derived return that is related to market value when the results are applied to the book value of a utility's**

**capitalization?**

A. The capital structure ratios measured at the utility's book value show more financial leverage, and higher risk, than the capitalization measured at its market values. Please refer to Attachment PRM-5 for the comparison. This means that a market-derived cost of equity, using models such as DCF and CAPM, reflects a level of financial risk that is different from that shown by the book value capitalization. Hence, it is necessary to develop a cost of equity that reflects the higher financial risk related to the book value capitalization used for ratesetting purposes. Failure to make this modification would result in a mismatch of the lower financial risk related to market value used to measure the cost of equity and the higher financial risk of the book value capital structure used in the ratesetting process. That is to say, the cost of equity for the Gas Group that is related to the 54.44% common equity ratio using book value has higher financial risk than the 68.29% common equity ratio using market values. Because the ratesetting process utilizes the book value capitalization, it is necessary to adjust the market-determined cost of equity for the higher financial risk related to the book value of the capitalization.

**Q. How is the DCF-determined cost of equity adjusted for the financial risk associated with the book value of the capitalization?**

A. In pioneering work, Nobel laureates Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that, as the borrowing of a firm increases, the expected return on stockholders' equity also increases. This principle is incorporated into my leverage adjustment which recognizes that the expected return on equity increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure that contains lower financial risk. Modigliani and

Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure. Simply stated, my leverage adjustment contains no factor for a particular market-to-book ratio. It merely expresses the cost of equity as the unleveraged return plus compensation for the additional risk of introducing debt and/or preferred stock into the capital structure. There can be no dispute that a firm's financial risk varies with the relative amount of leverage contained in its capital structure. As detailed in Attachment PRM-5, the Modigliani and Miller theory shows that the cost of equity increases by 0.54% (9.65% - 9.11%) when the book value of equity, rather than the market value of equity, is used to compute the weighted average cost of capital.

**Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.**

A. As explained previously, I have utilized a six-month average dividend yield ("$D_1$ /$P_0$") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g ") previously developed. The DCF also includes the leverage modification ("lev.") required when the book value equity ratio is used in determining the weighted average cost of capital in the ratesetting process rather than the market value equity ratio related to the price of stock. The cost of equity must also include an adjustment to cover flotation costs ("flot."). The factor used to develop the modification that would account for the flotation costs adjustment is provided in Attachment PRM-6 and Attachment PRM-17.

**Q. What DCF cost rate have you calculated?**

A. The resulting DCF cost rate is:

| | $D_1/P_0$ | + | $g$ | + | *lev.* | = | $k$ | x | *flot.* | = | $K$ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gas Goup | 3.86% | + | 5.25% | + | 0.54% | = | 9.65% | x | 1.02 | = | 9.84% |

As I have explained throughout my testimony, each method/model of the cost of equity contains certain assumptions that are not optimal. The DCF results provided above are one of several methods that I have used to measure the rate of return on common equity for the Company. Although the Commission has used the DCF model in the past, it has less significance in this case. Indeed, the DCF model is providing atypical results. That is to say, the low DCF returns can be traced in part to the unfavorable investor sentiment for the gas companies. As shown on page 5 of Attachment PRM-20, the gas distribution companies are viewed as relatively unattractive investments and are ranked 80 out of 98 industries by Value Line for probable performance over the next twelve months. In comparison, the regional electric companies are ranked 59 in the East, 65 in the Central and 82 in the West; while the water companies are ranked 91 for probable performance over the next twelve months. The significance of this low ranking is that performance for the gas companies is expected to be subpar, thereby indicating that the DCF results will not provide a cost of equity indication that corresponds with the results of the other methods/models. Indeed, the DCF results for the Gas Group are low, while the CAPM results show a much higher result for the Gas Group. This raises serious questions regarding the reliability of the DCF results for the Gas Group. Notwithstanding these failings, I have submitted a DCF calculation so the Commission will have that information. I have not ignored the DCF results, but rather I have assigned no more than equal weight to DCF than the two other methods (risk premium and CAPM) that I rely on.

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.19% (9.84% - 9.65%) to the rate of return on common equity for the Gas Group. In my opinion, this adjustment is reasonable for reasons explained in Attachment PRM-6. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant, which is another reason why the results of the DCF have limited usefulness in this case.

## RISK PREMIUM ANALYSIS

**Q. Please describe your use of the Risk Premium approach to determine the cost of equity.**

A. The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Attachment PRM-8. I will summarize them here. With this method, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. As with other models of the cost of equity, the Risk Premium approach has its limitations, including an accurate assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium.

**Q. What long-term public utility debt cost rate did you use in your risk premium analysis?**

A. In my opinion, a 6.00% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds. As I will subsequently show, the Moody's index and the Blue Chip forecasts support this figure.

The historical yields for long-term public utility debt are shown graphically on page 1 of Attachment PRM-18. For the twelve months ended October 2007, the average monthly yield on Moody's A-rated index of public utility bonds was 6.03%. For the six and three-month periods ended October 2007, the yields were 6.18% for both periods. During the twelve-months ended October 2007, the range of the yields on A-rated public utility bonds was 5.80% to 6.30%.

**Q. What forecasts of interest rates have you considered in your analysis?**

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe in Attachment PRM-7. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on January 1, 2008, and the yield spread of 1.25%, that is supported by the data shown on pages 3 and 4 of Attachment PRM-18 and explained in Attachment PRM-7. For comparative purposes, I also have shown the Blue Chip forecasts for Aaa-rated and Baa-rated corporate bonds:

| | | Blue Chip Financial Forecasts | | | | |
|---|---|---|---|---|---|---|
| | | Corporate | | 30-Year | A-rated Public Utility | |
| Year | Quarter | Aaa-rated | Baa-rated | Treasury | Spread | Yield |
| 2008 | First | 5.4% | 6.4% | 4.5% | 1.25% | 5.75% |
| 2008 | Second | 5.5% | 6.5% | 4.5% | 1.25% | 5.75% |
| 2008 | Third | 5.5% | 6.6% | 4.6% | 1.25% | 5.85% |
| 2008 | Fourth | 5.6% | 6.7% | 4.7% | 1.25% | 5.95% |
| 2009 | First | 5.7% | 6.8% | 4.8% | 1.25% | 6.05% |
| 2009 | Second | 5.8% | 6.9% | 4.9% | 1.25% | 6.15% |

**Q. Are there additional forecasts of interest rates that extend beyond those shown above?**

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2007 publication, the Blue Chip published forecasts of interest rates as follows:

| | Blue Chip Financial Forecasts | | | | |
|---|---|---|---|---|---|
| | Corporate | | 30-Year | A-rated Public Utility | |
| Averages | Aaa-rated | Baa-rated | Treasury | Spread | Yield |
| 2009-13 | 6.0% | 7.0% | 5.2% | 1.25% | 6.45% |
| 2014-18 | 6.1% | 7.0% | 5.3% | 1.25% | 6.55% |

Given these forecast interest rates, a 6.00% yield on A-rated public utility bonds represents a reasonable expectation.

**Q. How did you determine the equity risk premium for public utilities?**

A. Attachment PRM-8 provides a discussion of the financial returns that I relied upon to develop the appropriate equity risk premium for the S&P Public Utilities. I have calculated the equity risk premium by comparing the market returns on utility stocks and the market returns on utility bonds. I chose the S&P Public Utility index for the purpose of measuring the market returns for utility stocks. The S&P Public Utility index is reflective of the risk associated with regulated utilities, rather than some broader market indexes, such as the S&P 500 Composite index. The S&P Public Utility index is a subset of the overall S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of judgment in establishing the risk premium for public utilities. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Gas Group.

**Q. What equity risk premium for the S&P Public Utilities have you determined for this case?**

A. To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values set forth on page 2 of Attachment PRM-19, the indicated risk premiums for the various time periods analyzed are 5.37% (1928-2006), 6.40% (1952-2006), 5.61% (1974-2006), and 5.83% (1979-2006). The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals, and removes some of the more distant data from the analysis.

**Q. Do you have further support for the selection of the time periods used in your equity risk premium determination?**

A. Yes. First, the terminal year of my analysis presented in Attachment PRM-19 represents the returns realized through 2006. Second, the selection of the initial year of each period was based upon the events that I described in Attachment PRM-8. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the deregulation of the financial markets. As such, additional data are merely added to the earlier results when they become available, clearly showing that the periods chosen were not driven by the desired results of the study.

**Q. What conclusions have you drawn from these data?**

A. Using the summary values provided on page 2 of Attachment PRM-19, the 1928-2006 period provides the lowest indicated risk premium, while the 1952-2006 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.72% (5.61% + 5.83% = 11.44% ÷ 2) can be calculated from data covering the periods 1974-2006 and 1979-2006. Therefore, 5.72% represents a reasonable risk premium for the S&P Public Utilities in this case.

As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Gas Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals between the Gas Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 5.25% represents a reasonable common equity risk premium in this case. This represents approximately 92% (5.25% ÷ 5.72% = 0.92) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Gas Group compared to the S&P Public Utilities.

**Q. What common equity cost rate would be appropriate using this equity risk premium and the yield on long-term public utility debt?**

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of 11.44% as shown below.

| | $i$ | + | $RP$ | = | $k$ | + | $flot.$ | = | $K$ |
|---|---|---|---|---|---|---|---|---|---|
| Gas Group | 6.00% | + | 5.25% | = | 11.25% | + | 0.19% | = | 11.44% |

## CAPITAL ASSET PRICING MODEL

**Q. Have you used the Capital Asset Pricing Model to measure the cost of equity in this case?**

A. Yes, I have used the Capital Asset Pricing Model ("CAPM") in addition to my other methods. As with other models of the cost of equity, the CAPM contains a variety of assumptions that I discuss in Attachment PRM-9. Therefore, this method should be used with other methods to measure the cost of equity, as each will complement the other and will provide a result that will alleviate the unavoidable shortcomings found in each method.

**Q. What are the features of the CAPM as you have used it?**

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Attachment PRM-9. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("ß"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities. As such, to calculate the CAPM it is necessary to employ firms with traded stocks. In this regard, I performed a CAPM calculation for the Gas Group. In contrast, my Risk Premium approach also considers industry- and company-specific factors because it is not limited to measuring just systematic risk.

As a consequence, the Risk Premium approach is more comprehensive than the CAPM. In addition, the Risk Premium approach provides a better measure of the cost of equity because it is founded upon the yields on corporate bonds rather than Treasury bonds.

**Q. What betas have you considered in the CAPM?**

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 1 of Attachment PRM-20, the average beta is .86 for the Gas Group.

**Q. What betas have you used in the CAPM determined cost of equity?**

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless those betas are applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book value capital structure, the Value Line betas have been unleveraged and releveraged for the common equity ratios using book values using the Hamada formula. This adjustment has been made with the formula:

$$ßl = ßu\,[1 + (1 - t)\,D/E + P/E]$$

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and therefore are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at its market values, the beta would become .66 for the Gas Group if it employed no leverage and was 100% equity financed. With the unleveraged beta as a base, I calculated the leveraged beta of 1.02 for the Gas Group associated with book value capital structure. The betas and their corresponding common equity ratios are:

| Market Values | | Book Values | |
|---|---|---|---|
| Beta | Common Equity Ratio | Beta | Common Equity Ratio |
| 0.86 | 68.29% | 1.02 | 54.44% |

The leveraged beta that I will employ in the CAPM cost of equity is 1.02 for the Gas Group.

**Q. What risk-free rate have you used in the CAPM?**

A. For reasons explained in Attachment PRM-7, I have employed the yields on 20-year Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratesetting process. As shown on pages 2 and 3 of Attachment PRM-20, I provided the historical yields on Treasury notes and bonds. For the twelve months ended October 2007, the average yield on a 20-year Treasury Bond was 4.94%, as shown on page 3 of that attachment. For the six- and three-months ended October 2007, the yields on 20-year Treasury bonds were 5.02% and 4.89%, respectively. During the twelve-months ended October 2007, the range of the yields on 20-year Treasury bonds was 4.78% to 5.29%. As shown on page 4 of Attachment PRM-20, forecasts published by Blue Chip on January 1, 2008 indicate that the yields on long-term Treasury bonds are expected to be in the range of 4.5% to 4.9% during the next six quarters. The longer term forecasts described previously show that the yields on Treasury bonds will average 5.2% from 2009 through 2013 and 5.3% from 2014 to 2018. Hence, I have used a 4.75% risk-free rate of return for CAPM purposes, which reflects the recent easing of monetary policy by the Federal Open Market Committee.

**Q. What market premium have you used in the CAPM?**

A. As developed in Attachment PRM-9, the market premium is developed by averaging historical market performance (i.e., 6.5%) and the forecasts (i.e., 8.28%). For the historically based market premium, I have used the arithmetic mean. The resulting market premium is 7.39% (6.5% + 8.28% = 14.78% ÷ 2), which represents the average market premium using historical and forecast data.

**Q. Are there adjustments to the CAPM results that are necessary to fully reflect the rate of return on common equity?**

A. Yes. The literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. There would be an understatement of a firm's cost of equity with the CAPM unless the size of a firm is considered. That is to say, as the size of a firm decreases, its risk and, hence, its required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs then otherwise similar larger firms (see Fundamentals of Financial Management, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the costs of equity for stocks in lower deciles (i.e., smaller stocks) were in excess of those shown by the simple CAPM. In this regard, the Gas Group has an average equity market capitalization of $1,775 million, which would make it a low cap portfolio. As noted previously, the Company is even smaller than the Gas Group, which would place it in the micro-cap category, which commands an even higher size adjustment. The low cap market capitalization would indicate a size premium of 1.76%. Absent such an adjustment, the CAPM would understate the required return. However, for my CAPM analysis, I have adopted a more conservative size adjustment of 0.97%, which represents the mid-cap adjustment, because the market cap of the Gas Group was near the threshold of the midcap group.

**Q. What result have you determined using the CAPM?**

A. Using the 4.75% risk-free rate of return, the leverage adjusted beta of 1.02 for the Gas Group, the 7.39% market premium, the size adjustment, and the flotation cost adjustment, the following result is indicated.

| | *Rf* | + | *ß* | x ( | *Rm-Rf* | ) + | *size* | = | *k* | + | *flot* | = | *K* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gas Group | 4.75% | + | 1.02 | x ( | 7.39% | ) + | 0.97% | = | 13.26% | + | 0.19% | = | 13.45% |

## COMPARABLE EARNINGS APPROACH

**Q. How have you applied the Comparable Earnings approach in this case?**

A. The technical aspects of the Comparable Earnings approach are set forth in Attachment PRM-10. Because regulation is a substitute for competitively-determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. In order to identify the appropriate return, it is necessary to analyze returns earned (or realized) by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided. There are two avenues available to implement the Comparable Earnings approach. One method would involve the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry would serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms. As such, this approach to Comparable Earnings avoids the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.... The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

Therefore, it is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

**Q. How have you implemented the Comparable Earnings approach?**

A. To identify the comparable risk companies, the Value Line Investment Survey for Windows was used to screen for firms of comparable risks. The Value Line Investment Survey for Windows includes data on approximately 1700 firms. Excluded from the selection process were companies incorporated in foreign countries and master limited partnerships (MLPs). In order to implement the Comparable Earnings approach, non-regulated companies were selected from the Value Line Investment Survey for Windows that have six categories (see Attachment PRM-10 for definitions) of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were:

Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The identities of the companies comprising the Comparable Earnings group and its associated rankings within the ranges are identified on page 1 of Attachment PRM-21.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Attachment PRM-21, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors for selecting stocks, it is an appropriate database for measuring comparable return opportunities.

**Q. What data have you used in your Comparable Earnings analysis?**

A. I have used both historical realized returns and forecast returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization because, the nature of the analysis relates to book value. Hence, Comparable Earnings does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. The historical rate of return on book common equity was 14.3% using the median value as shown on page 2 of Attachment PRM-21. The forecast rates of return, as published by Value Line are shown by the 13.5% median values also provided on page 2 of Attachment PRM-21.

**Q. What rate of return on common equity have you determined in this case using the Comparable Earnings approach?**

A. The average of the historical and forecast median rates of return is:

| | *Historical* | *Forecast* | *Average* |
|---|---|---|---|
| Comparable Earnings Group | 14.30% | 13.50% | 13.90% |

**CONCLUSION ON RATE OF RETURN**

**Q. What is your conclusion concerning the Company's cost of common equity?**

A. As discussed previously, it is essential that the Commission consider a variety of techniques to determine the Company's rate of return on common equity because of the limitations/infirmities that are inherent is each method. Based upon the application of the variety of methods and models that I have used, it is my opinion that the reasonable rate of return on common equity is 11.50% for the Company.

**Q. Does this conclude your prepared direct testimony?**

A. Yes.

# EnergyNorth Natural Gas, Inc.
# d/b/a National Grid NH

Attachments PRM-1 through PRM-10
to Accompany the
Direct Testimony

of

Paul R. Moul
Managing Consultant
P. Moul & Associates

Concerning
Cost of Capital

## EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies as well as responsibility for various treasury functions of the American Water Works System's thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service regulated firms. In this regard, I have supervised the preparation of rate of return studies that were employed in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty (30) federal, state and municipal regulatory commissions, including: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, and West Virginia; and the Philadelphia Gas Commission. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of

Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000).

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

I am a member of the Society of Utility and Regulatory Financial Analysis (formerly the National Society of Rate of Return Analysts) and have attended several Financial Forums sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-Wythe School of Law, College of William and Mary. I also attended an Executive Seminar sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October

1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

| Date | Occasion | Sponsor |
|---|---|---|
| April 2006 | Thirty-eighth Financial Forum | Society of Utility & Regulatory Financial Analysts |
| April 2001 | Thirty-third Financial Forum | Society of Utility & Regulatory Financial Analysts |
| December 2000 | Pennsylvania Public Utility Law Conference: Non-traditional Players in the Water Industry | Pennsylvania Bar Institute |
| July 2000 | EEI Member Workshop Developing Incentives Rates: Application and Problems | Edison Electric Institute |
| February 2000 | The Sixth Annual FERC Briefing | Exnet and Bruder, Gentile & Marcoux, LLP |
| March 1994 | Seventh Annual Proceeding | Electric Utility Business Environment Conf. |
| May 1993 | Financial School | New England Gas Assoc. |
| April 1993 | Twenty-Fifth Financial Forum | National Society of Rate of Return Analysts |
| June 1992 | Rate and Charges Subcommittee Annual Conference | American Water Works Association |
| May 1992 | Rates School | New England Gas Assoc. |
| October 1989 | Seventeenth Annual Eastern Utility Rate Seminar | Water Committee of the National Association of Regulatory Utility Commissioners Florida Public Service Commission and University of Utah |
| October 1988 | Sixteenth Annual Eastern Utility Rate Seminar | Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah |
| May 1988 | Twentieth Financial Forum | National Society of Rate of Return Analysts |

| | | |
|---|---|---|
| October 1987 | Fifteenth Annual Eastern Utility Rate Seminar | Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah |
| September 1987 | Rate Committee Meeting | American Gas Association |
| May 1987 | Pennsylvania Chapter annual meeting | National Association of Water Companies |
| October 1986 | Eighteenth Financial Forum | National Society of Rate of Return |
| October 1984 | Fifth National on Utility Ratemaking Fundamentals | American Bar Association |
| March 1984 | Management Seminar | New York State Telephone Association |
| February 1983 | The Cost of Capital Seminar | Temple University, School of Business Admin. |
| May 1982 | A Seminar on Regulation and The Cost of Capital | New Mexico State University, Center for Business Research and Services |
| October 1979 | Economics of Regulation | Brown University |

**RATESETTING PRINCIPLES**

Traditional cost of service regulation, as implemented by a regulatory agency engaged in ratesetting, such as the Commission, serves as a substitute for competition. In setting rates, a regulatory agency must carefully consider the public's interest in reasonably priced, as well as safe and reliable, service. The level of rates must also provide the public utility and its investors with an opportunity to earn a rate of return for the public utility and its investors that is commensurate with the risk to which the invested capital is exposed so that the public utility has access to the capital required to meet its service responsibilities to its customers. Without an opportunity to earn a fair rate of return, a public utility will be unable to attract sufficient capital required to meet its responsibilities over time.

It is important to remember that regulated firms must compete for capital in a global market with non-regulated firms, as well as municipal, state and federal governments. Traditionally, a public utility has been responsible for providing a particular type of service to its customers within a specific market area. Although this relationship with customers has been changing, a regulated utility remains quite different from a non-regulated firm which is free to enter and exit competitive markets in accordance with available business opportunities.

As established by the landmark Bluefield and Hope cases,[1] several tests have been articulated through which the regulator can determine the fairness or reasonableness of the rate of return. These tests include a determination of whether the rate of return is (i) similar to that of other financially sound businesses having similar or comparable risks, (ii) sufficient to ensure confidence in the financial integrity of the public utility, and (iii) adequate to maintain and support the credit of the utility, thereby enabling it to attract, on a reasonable cost basis,

1 Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

the funds necessary to satisfy its capital requirements so that it can meet the obligation to provide adequate and reliable service to the public.

A fair rate of return must not only provide the utility with the ability to attract new capital, but it must also be fair to existing investors. An appropriate rate of return which may have been reasonable at one point in time may become too high or too low at a subsequent point in time, based upon changing business risks, economic conditions and alternative investment opportunities. When applying the standards of a fair rate of return, it must be recognized that the end result must provide for the payment of interest on the company's debt, the payment of dividends on the company's stock, the recovery of costs associated with securing capital, the maintenance of reasonable credit quality for the company, and support of the company's financial condition, which today would include those measures of financial performance in the areas of interest coverage and adequate cash flow derived from a reasonable level of earnings.

## EVALUATION OF RISK

The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk, all else being equal. Because investors will seek the highest rate of return available considering the risk involved, the rate of return must at least equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm is often defined as the uncertainty of achieving expected performance, and is sometimes viewed as a probability distribution of possible outcomes. Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a consequence, high risk firms must offer investors higher returns than low risk firms, which pay less to attract capital from investors. This is because the level of uncertainty, or risk of not realizing expected returns, establishes the compensation required by investors in the capital markets. Of course, the risk of a firm must also be considered in the context of its ability to actually experience adequate earnings which conform with a fair rate of return. Thus, if there is a high probability that a firm will not perform well due to fundamentally poor market conditions, investors will demand a higher return.

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated firms than for non-regulated companies. When rates are set for regulated public utilities, the cost of service formula gives the benefits of financial leverage to consumers in the form of lower revenue requirements, since the cost of borrowed funds is generally lower than the cost of equity invested in the company. For non-regulated companies, all benefits of financial leverage are retained by the common stockholder. Although retaining none of the benefits, regulated firms bear the risk of financial leverage. Therefore, a regulated firm's rate of return on common equity must recognize the greater financial risk shown by the higher leverage typically employed by public utilities.

Although no single index or group of indices can precisely quantify the relative investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators, which are reflective of business risk, include the variability of the rate of return on equity, which is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and taxes other than income tax), which are indicative of profitability; the quality of earnings, which considers the degree to which earnings are the product of accounting principles or cost deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital in a company's capitalization is the measure of financial risk which is often analyzed in the context of the equity ratio (i.e., the complement of the debt ratio).

## COST OF EQUITY--GENERAL APPROACH

Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation which lacks such a basis will inevitably fail to provide a utility with a fair rate of return except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods which have been employed to measure the cost of equity include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be relied upon exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors. To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the payment of interest and principal to creditors has priority over the payment of dividends and return of capital to equity investors. Hence, equity investors require a higher rate of return than the yield on long-term corporate bonds.

The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the yield on a risk-free interest-bearing obligation, plus a premium as compensation for risk. Aside from the reliance on the risk-free rate of return, the CAPM gives specific quantification to systematic (or market) risk as measured by beta.

The Comparable Earnings approach measures the returns expected/experienced by other non-regulated firms and has been used extensively in rate of return analysis for over a half century. However, its popularity diminished in the 1970s and 1980s with the popularization of market-based models. Recently, there has been renewed interest in this approach. Indeed, the financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector so that public utilities can compete effectively in the capital markets. With additional competition being introduced throughout the traditionally regulated public utility industry, returns expected to be realized by non-regulated firms have become increasingly relevant in the ratesetting process. The Comparable Earnings approach considers directly those requirements, and it fits the established standards for a fair rate of return set forth in the landmark decisions on the issue of rate of return. These decisions require that a fair return for a utility must be equal to that earned by firms of comparable risk.

**DISCOUNTED CASH FLOW ANALYSIS**

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if $100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be $46.32 (Value = $\$100 \div (1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present $46.32 price of an asset (where price = value), the $100 future expected cash flow to be received 10 years hence shows an 8% annual rate of return implicit in the price and future cash flows expected to be received.

In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate which reflects the risk or uncertainty associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If $P$ represents price, $Kp$ is the required rate of return on a preferred stock, and $D$ is the annual dividend ($P$ and $D$ with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, $Kp$. In this circumstance:

$$P_0 = \frac{D_1}{(1+Kp)} + \frac{D_2}{(1+Kp)^2} + \frac{D_3}{(1+Kp)^3} + \ldots + \frac{D_n}{(1+Kp)^n}$$

If $D_1 = D_2 = D_3 = \ldots D_n$ as is the case for preferred stock, and $n$ approaches infinity, as is the case for non-callable preferred stock without a sinking fund, then this equation reduces to:

$$P_0 = \frac{D_1}{Kp}$$

This equation can be used to solve for the annual rate of return on a preferred stock when the current price and subsequent annual dividends are known. For example, with $D_1$ = \$1.00, and $P_0$ = \$10, then $Kp$ = \$1.00 ÷ \$10, or 10%.

The dividend discount equation, first shown, is the generic DCF valuation model for all equities, both preferred and common. While preferred stock generally pays a constant dividend, permitting the simplification subsequently noted, common stock dividends are not constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the generic form of the DCF. If, however, it is assumed that $D_1, D_2, D_3, \ldots D_n$ are systematically related to one another by a constant growth rate $(g)$, so that $D_0 (1 + g) = D_1$, $D_1 (1 + g) = D_2$, $D_2 (1 + g) = D_3$ and so on approaching infinity, and if $Ks$ (the required rate of return on a common stock) is greater than $g$, then the DCF equation can be reduced to:

$$P_0 = \frac{D_1}{Ks - g} \quad or \quad P_0 = \frac{D_0(1+g)}{Ks - g}$$

which is the periodic form of the "Gordon" model.[1] Proof of the DCF equation is found in all

1 Although the popular application of the DCF model is often attributed to the work of Myron J.

modern basic finance textbooks. This DCF equation can be easily solved as:

$$Ks = \frac{D_0\,(1+g)}{P_0} + g$$

which is the periodic form of the Gordon Model commonly applied in estimating equity rates of return in rate cases. When used for this purpose, *Ks* is the annual rate of return on common equity demanded by investors to induce them to hold a firm's common stock. Therefore, the variables $D_0$, $P_0$ and *g* must be estimated in the context of the market for equities, so that the rate of return, which a public utility is permitted the opportunity to earn, has meaning and reflects the investor-required cost rate.

Application of the Gordon model with market derived variables is straightforward. For example, using the most recent prior annualized dividend $(D_0)$ of \$0.80, the current price $(P_0)$ of \$10.00, and the investor expected dividend growth rate *(g)* of 5%, the solution of the DCF formula provides a 13.4% rate of return. The dividend yield component in this instance is 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual rate of return required by investors. The capital gain component of the total return may be calculated with two adjacent future year prices. For example, in the eleventh year of the holding period, the price per share would be \$17.10 as compared with the price per share of \$16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

Some DCF devotees believe that it is more appropriate to estimate the required return on equity with a model which permits the use of multiple growth rates. This may be a plausible

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Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

approach to DCF, where investors expect different dividend growth rates in the near term and long run. If two growth rates, one near term and one long-run, are to be used in the context of a price *($P_0$)* of \$10.00, a dividend *($D_0$)* of \$0.80, a near-term growth rate of 5.5%, and a long-run expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

**Dividend Yield**

The historical annual dividend yield for the Gas Group is shown on Attachment PRM-12. The 2002-2006 five-year average dividend yield was 4.2% for the Gas Group. The monthly dividend yields for the twelve months ending in December 2007 are shown graphically on Attachment PRM-14. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs two business days before the record date of the dividend (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). During a quarter (here defined as 91 days), the price of a stock moves up ratably by the dividend amount as the ex-dividend date approaches. The stock's price then falls by the amount of the dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the quarterly dividend since the time of the last ex-dividend date and to remove that amount from the price. This adjustment reflects normal recurring pricing of stocks in the market, and establishes a price that will reflect the true yield on a stock.

A six-month average dividend yield has been used to recognize the prospective orientation of the ratesetting process as explained in the direct testimony. For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized. An adjustment to the dividend yield component, when computed with annualized dividends, is required based upon investor expectation of quarterly dividend increases.

The procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, developed below. The DCF equation, showing the quarterly dividend payments as $D_0$, may be stated in this fashion:

$$K = \frac{D_0 (1+g)^0 + D_0 (1+g)^0 + D_0 (1+g)^1 + D_0 (1+g)^1}{P_0} + g$$

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, is 2.625% (5.25% x .5) for the Gas Group, which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield is 3.85% (3.75% x 1.02625) for the Gas Group.

Another DCF model that reflects the discrete growth in the quarterly dividend $(D_0)$ is as follows:

$$K = \frac{D_0 (1+g)^{.25} + D_0 (1+g)^{.50} + D_0 (1+g)^{.75} + D_0 (1+g)^{1.00}}{P_0} + g$$

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 3.87% (3.75% x 1.03260) for the Gas Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

In either of the preceding DCF dividend yield adjustments, there is no recognition for the compound returns attributed to the quarterly dividend payments. Investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the

$$k = \left[ \left( 1 + \frac{D_0}{P_0} \right)^4 - 1 \right] + g$$

periodic quarterly dividend payments *($D_0$)*, results in a third DCF formulation: This DCF equation provides no further recognition of growth in the quarterly dividend. Combining discrete quarterly dividend growth with quarterly compounding would provide the following DCF formulation, stating the quarterly dividend payments *($D_0$)*:

$$k = \left[ \left( 1 + \frac{D_0 (1 + g)^{.25}}{P_0} \right)^4 - 1 \right] + g$$

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was

0.9375% (3.75% ÷ 4) for the Gas Group. The compound dividend yield would be 3.85% ($1.009496^4$-1) for the Gas Group, recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For the Gas Group, a 3.86% forward-looking dividend yield is the average (3.85% + 3.87% + 3.85% = 11.57% ÷ 3) of the adjusted dividend yield using the form $D_0/P_0\ (1+.5g)$, the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth.

**Growth Rate**

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. It would, however, require 100 years of future dividend payments so that the discounted value of those payments would equate to the present price so that the discount rate and the rate of return shown by the simplified Gordon form of the DCF model would be about the same. A century of dividend receipts represents an unrealistic investment horizon from almost any perspective. Because stocks are not held by investors forever, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, investor expected returns in the equity market are provided by capital appreciation of the investment as well as receipt of dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment holding period to arrive at the investor expected return.

In its constant growth form, the DCF assumes that with a constant return on book common equity and constant dividend payout ratio, a firm's earnings per share, dividends per share and book value per share will grow at the same constant rate, absent any external financing by a firm. Because these constant growth assumptions do not actually prevail in the capital markets, the capital appreciation potential of an equity investment is best measured by the expected growth in earnings per share. Since the traditional form of the DCF assumes no change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as earnings per share. Hence, the capital gains yield is best measured by earnings per share growth using company-specific variables.

Investors consider both historical and projected data in the context of the expected growth rate for a firm. An investor can compute historical growth rates using compound growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth rates as provided in widely-circulated, influential publications. However, a traditional constant growth DCF analysis that is limited to such inputs suffers from the assumption of no change in the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as earnings. Some of the factors which actually contribute to investors' expectations of earnings growth and which should be considered in assessing those expectations, are: (i) the earnings rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of additional common equity, (iv) reacquisition of common stock previously issued, (v) changes in financial leverage, (vi) acquisitions of new business opportunities, (vii) profitable liquidation of assets, and (viii) repositioning of existing assets. The realities of the equity market regarding total return expectations, however, also reflect factors other than these inputs. Therefore, the DCF model contains overly restrictive limitations when the growth component is stated in terms of earnings per share (the basis for the capital gains yield) or dividends per share (the basis for the infinite dividend discount model). In these situations, there is inadequate recognition of the capital gains yields arising from stock price growth which could exceed earnings or dividends growth.

To assess the growth component of the DCF, analysts' projections of future growth influence investor expectations as explained above. One influential publication is The Value Line Investment Survey which contains estimated future projections of growth. The Value Line Investment Survey provides growth estimates which are stated within a common economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical economic environment is represented by components and subcomponents of the National Income Accounts which reflect in the aggregate assumptions concerning the unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales, earnings and dividends of a company to appropriate components or subcomponents of the future National Income Accounts. These calculations provide a consistent basis for the published forecasts. Value Line's evaluation of a specific company's future prospects are considered in the context of specific operating characteristics that influence the published projections. Of particular importance for regulated firms, Value Line considers the regulatory quality, rates of return recently authorized, the historic ability of the firm to actually experience the authorized rates of return, the firm's budgeted capital spending, the firm's financing forecast, and the dividend payout ratio. The wide circulation of this source and frequent reference to Value Line in financial circles indicate that this publication has an influence on investor judgment with regard to expectations for the future.

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("IBES"). The IBES service provides data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts. The earnings estimates are obtained from financial analysts at brokerage research departments and from institutions whose securities analysts are projecting earnings for companies in the First Call universe of companies. Other services that tabulate earnings forecasts and publish them are Zacks Investment Research and Market Guide (which is provided over the Internet by Reuters). As with the IBES/First Call forecasts, Zacks and Reuters/Market Guide provide consensus forecasts collected from analysts for most publically traded companies.

In each of these publications, forecasts of earnings per share for the current and subsequent year receive prominent coverage. That is to say, IBES/First Call, Zacks, Reuters/Market Guide, and Value Line show estimates of current-year earnings and projections for the next year. While the DCF model typically focuses upon long-run estimates of growth, stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the near-term earnings per share growth rates should also be factored into a growth rate determination.

Although forecasts of future performance are investor influencing[2], equity investors may also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. It is

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2 As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

apparent that any serious investor would advise himself/herself of historical performance prior to taking an investment position in a firm. Earnings per share and dividends per share represent the principal financial variables which influence investor growth expectations.

Other financial variables are sometimes considered in rate case proceedings. For example, a company's internal growth rate, derived from the return rate on book common equity and the related retention ratio, is sometimes considered. This growth rate measure is represented by the Value Line forecast "*BxR*" shown on Attachment PRM-16. Internal growth rates are often used as a proxy for book value growth. Unfortunately, this measure of growth is often not reflective of investor-expected growth. This is especially important when there is an indication of a prospective change in dividend payout ratio, earned return on book common equity, change in market-to-book ratios or other fundamental changes in the character of the business. Nevertheless, I have also shown the historical and projected growth rates in book value per share and internal growth rates.

## Leverage Adjustment

As noted previously, the divergence of stock prices from book values creates a conflict within the DCF model when the results of a market-derived cost of equity are applied to the common equity account measured at book value in the ratesetting context. This is the situation today where the market price of stock exceeds its book value for most companies. This divergence of price and book value also creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value. It is a well-accepted fact of financial theory that a relatively higher proportion of equity in the capitalization has less financial risk than another capital structure more heavily weighted with debt. This is the situation for the

Gas Group where the market value of its capitalization contains more equity than is shown by the book capitalization. The following comparison demonstrates this situation where the market capitalization is developed by taking the "Fair Value of Financial Instruments" (Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting Standards ("FAS") No. 107) as shown in the annual report for these companies and the market value of the common equity using the price of stock. The comparison of capital structure ratios is:

| Gas Group | Capitalization at Market Value (Fair Value) | Capitalization at Book Value (Carrying Amounts) |
|---|---|---|
| Long-term Debt | 31.52% | 45.29% |
| Preferred Stock | 0.19% | 0.26% |
| Common Equity | 68.29% | 54.44% |
| Total | 100.00% | 100.00% |

With regard to the capital structure ratios represented by the carrying amounts shown above, there are some variances from the ratios shown on Attachment PRM-12. These variances arise from the use of balance sheet values in computing the capital structure ratios shown on Attachment PRM-12 and the use of the Carrying Amounts of the Financial Instruments according to FAS 107 (the Carrying Amounts were used in the table shown above to be comparable to the Fair Value amounts used in the comparison calculations).

With the capital ratios calculated above, it is necessary to first calculate the cost of equity for a firm without any leverage. The cost of equity for an unleveraged firm using the capital structure ratios calculated with market values is:

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D / E) - (ku - d)\ P / E$$

$$8.43\% = 9.11\% - (((8.43\% - 6.18\%)\ .65)\ 31.52\%/68.29\%) - (8.43\% - 6.12\%)\ 0.19\%/68.29\%$$

where $ku$ = cost of equity for an all-equity firm, $ke$ = market determined cost equity, $i$ = cost of debt[3], $d$ = dividend rate on preferred stock[4], $D$ = debt ratio, $P$ = preferred stock ratio, and $E$ = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 8.43% using the market value of the Gas Group's capitalization. Having determined that the cost of equity is 8.43% for a firm with 100% equity, the rate of return on common equity associated with the book value capital structure is:

$$ke = ku + (((ku - i)\ 1\text{-}t)\ D / E) + (ku - d)\ P / E$$

$$9.65\% = 8.43\% + (((8.43\% - 6.18\%)\ .65)\ 45.29\%/54.44\%) + (8.43\% - 6.12\%)\ 0.26\%/54.44\%$$

3 The cost of debt is the six-month average yield on Moody's A rated public utility bonds.

4 The cost of preferred is the six-month average yield on Moody's "a" rated preferred stock.

**FLOTATION COST ADJUSTMENT**

The rate of return on common equity must be high enough to avoid dilution when additional common equity is issued. In this regard, the rate of return on book common equity for public utilities requires recognition of specific factors other than just the market-determined cost of equity. A market price of common stock above book value is necessary to attract future capital on reasonable terms in competition with other seekers of equity capital. Non-regulated companies traditionally have experienced common stock prices consistently above book value. For a public utility to be competitive in the capital markets, similar recognition should be provided, given the understated value of net plant investment which is represented by historical costs much lower than current cost. Moreover, the market value of a public utility stock must be above book value to provide recognition of market pressure, issuance and selling expenses which reduce the net proceeds realized from the sale of new shares of common stock. A market price of stock above book value will maintain the financial integrity of shares previously issued and is necessary to avoid dilution when new shares are offered.

The rate of return on common equity should provide for the underwriting discount and company issuance expenses associated with the sale of new common stock. It is the net proceeds, after payment of these costs that are available to the company, because the issuance costs are paid from the initial offering price to the public. Market pressure occurs when the news of an impending issue of new common shares impacts the pre-offering price of stock. The stock price often declines because of the prospect of an increase in the supply of shares. The difficulty encountered in measuring market pressure relates to the time frame considered, general market conditions, and management action during the offering period. An indication of negative market pressure could be the product of the techniques employed to measure pressure and not the prospect of an additional supply of shares related to the new issue.

Even in the situation where a company will not issue common stock during the near term, the flotation cost adjustment factor should be applied to the common equity cost rate. A public utility must be in a competitive capital attraction posture at all times. To deny recognition of a market value of equity above book value would be discriminatory when other comparable companies receive an allowance in this regard. Moreover, to reduce the return rate on common equity by failing to recognize this factor would likewise result in a company being less competitive in the bond market, because a lower resulting overall rate of return would provide less competitive fixed-charge coverage. It cannot be said that a public utility's stock price already considers an allowance for flotation costs. This is because investors in either fixed-income bonds or common stocks seek their required rate of return by reference to alternative investment opportunities, and are not concerned with the issuance costs incurred by a firm borrowing long-term debt or issuing common equity.

Historical data concerning issuance and selling expenses (excluding market pressure) is shown on Attachment PRM-17. To adjust for the cost of raising new common equity capital, the rate of return on common equity should recognize an appropriate multiple in order to allow for a market price of stock above book value. This would provide recognition for flotation costs, which are shown to be 3.9% for public offerings of common stocks by gas companies from 2002 to 2006. Because these costs are not recovered elsewhere, they must be recognized in the rate of return. Since I apply the flotation cost to the entire cost of equity, I have only used a modification factor of 1.02 which is applied to the unadjusted DCF-measure of the cost of equity to cover issuance expense. If the modification factor were applied to only a portion of the cost of equity, such as just the dividend yield, then a higher factor would be necessary.

## INTEREST RATES

Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors' willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation that is reflected in current interest rates, may be quite different than the prevailing rate of inflation.

Federal Reserve Board ("Fed") policy actions, which impact directly short-term interest rates, also substantially affect investor sentiment in long-term fixed-income securities markets. In this regard, the Fed has often pursued policies designed to build investor confidence in the credit markets. Formative Fed policy has had a long history, as exemplified by the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the financial system which increased the level and volatility of interest rates. The Fed has indicated that it will follow a monetary policy designed to promote non-inflationary economic growth.

Rates of interest vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity risk.

## **Public Utility Bond Yields**

The Risk Premium analysis of the cost of equity, which is discussed in Attachment PRM-8, is represented by the combination of a firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the additional risk associated with the equity of a firm. Due to the senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the prior claim which lenders have on the earnings and assets of a corporation.

As a generalization, all interest rates track to varying degrees of the benchmark yields established by the market for Treasury securities. Public utility bond yields usually reflect the underlying Treasury yield associated with a given maturity plus a spread to reflect the specific credit quality of the issuing public utility. Market sentiment can also have an influence on the spreads as described below. The spread in the yields on public utility bonds and Treasury bonds varies with market conditions, as does the relative level of interest rates at varying maturities shown by the yield curve.

Pages 1 and 2 of Attachment PRM-18 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of

Aaa, Aa, A, and Baa are known as "investment grades" and are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Attachment PRM-18. There, it is shown that those spreads were about one percentage point during for the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to the run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As shown on page 3 of Attachment PRM-18, the spread in yields between A-rated public utility bonds and 20-year Treasury bonds were about one percentage point prior to 1998, 1.32% in 1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.62% in 2003, 1.12% in 2004, 1.01% in 2005, and 1.08% in 2006. As shown by the monthly data presented on pages 4 and 5 of Attachment PRM-18, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 1.09 percentage points for the twelve-months ended October 2007. For the six- and three-month periods ending

October 2007, the yield spread was 1.16% and 1.29%, respectively. Spreads widened with the development of the credit crunch in the third quarter of 2007.

**Risk-Free Rate of Return in the CAPM**

Regarding the risk-free rate of return (see Attachment PRM-9), pages 2 and 3 of Attachment PRM-20 provide the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

> The Cost of Capital in a Regulatory Environment. When discounting cash flows projected over a long period, it is necessary to discount them by a long-term cost of capital. Additionally, regulatory processes for setting rates often specify or suggest that the desired rate of return for a regulated firm is that which would allow the firm to attract and retain debt and equity capital over the long term. Thus, the long-term cost of capital is typically the appropriate cost of capital to use in regulated ratesetting. (Stocks, Bonds, Bills and Inflation - 1992 Yearbook, pages 118-119)

As indicated above, long-term Treasury bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be avoided for several reasons. First, rates should be set on the basis of financial conditions that will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy, political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds.

**RISK PREMIUM ANALYSIS**

The cost of equity requires recognition of the risk premium required by common equities over long-term corporate bond yields. In the case of senior capital, a company contracts for the use of long-term debt capital at a stated coupon rate for a specific period of time and in the case of preferred stock capital at a stated dividend rate, usually with provision for redemption through sinking fund requirements. In the case of senior capital, the cost rate is known with a high degree of certainty because the payment for use of this capital is a contractual obligation, and the future schedule of payments is known. In essence, the investor-expected cost of senior capital is equal to the realized return over the entire term of the issue, absent default.

The cost of equity, on the other hand, is not fixed, but rather varies with investor perception of the risk associated with the common stock. Because no precise measurement exists as to the cost of equity, informed judgment must be exercised through a study of various market factors which motivate investors to purchase common stock. In the case of common equity, the realized return rate may vary significantly from the expected cost rate due to the uncertainty associated with earnings on common equity. This uncertainty highlights the added risk of a common equity investment.

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. As noted in Attachment PRM-7, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a lender. The cost of equity stated in terms of the familiar risk premium approach is:

$k = i + RP$

where, the cost of equity *("k")* is equal to the interest rate on long-term corporate debt *("i")*, plus an equity risk premium *("RP")* which represents the additional compensation for the riskier common equity.

## Equity Risk Premium

The equity risk premium is determined as the difference in the rate of return on debt capital and the rate of return on common equity. Because the common equity holder has only a residual claim on earnings and assets, there is no assurance that achieved returns on common equities will equal expected returns. This is quite different from returns on bonds, where the investor realizes the expected return during the entire holding period, absent default. It is for this reason that common equities are always more risky than senior debt securities. There are investment strategies available to bond portfolio managers that immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas no such redemption is mandated for public utility common equities.

It is well recognized that the expected return on more risky investments will exceed the required yield on less risky investments. Neither the possibility of default on a bond nor the maturity risk detracts from the risk analysis, because the common equity risk rate differential (i.e., the investor-required risk premium) is always greater than the return components on a bond. It should also be noted that the investment horizon is typically long-run for both corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or starting point with which to track and measure the cost rate of common equity capital. There is no need to segment the bond yield according to its components, because it is the total return demanded by investors that is important for determining the risk rate differential for common equity. This is because the complete bond yield provides the basis to determine the differential, and as such, consistency requires that the computed differential must be applied to the complete bond yield when applying the risk premium approach. To apply the risk rate differential to a partial bond yield would result in a misspecification of the cost of equity because the computed differential was initially determined by reference to the entire bond return.

The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (here defined as one year) computed over long time spans. This analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved. Accordingly, historical holding period returns must not be analyzed over an unduly short period because near-term realized results may not have fulfilled investors' expectations. Moreover, specific past period results may not be representative of investment fundamentals expected for the future. This is especially apparent when the holding period returns include negative returns which are not representative of either investor requirements of the past or investor expectations for the future. The short-run phenomenon of unexpected returns (either positive or negative) demonstrates that an unduly short historical period would not adequately support a risk premium analysis. It is important to distinguish between investors' motivation to invest, which encompass positive return expectations, and the knowledge that losses can occur. No rational investor would forego payment for the use of capital, or expect loss of principal, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Attachment PRM-19 provides the historical holding period returns for the S&P Public Utility Index which has been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in Stocks, Bonds, Bills and Inflation published by Ibbotson & Associates. The tabulation begins with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public Utility Index. I have considered all reliable data for this study to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

The risk rate differentials for all equities, as measured by the S&P Composite, are established by reference to long-term corporate bonds. For public utilities, the risk rate differentials are computed with the S&P Public Utilities as compared with public utility bonds.

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of the central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be appropriate. The median returns are also appropriate in ratesetting because they are a measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return which divides the entire series of annual returns in half and are representative of a return that symbolizes, in a meaningful way, the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Attachment PRM-9, the long-term cost of capital in rate cases requires the use of the arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2006, the risk premiums for each class of equity are:

| | S&P Composite | S&P Public Utilities |
|---|---|---|
| Arithmetic Mean | 5.86% | 5.41% |
| Geometric Mean | 4.25% | 3.35% |
| Median | 10.17% | 7.29% |
| Midpoint of Range | 7.21% | 5.32% |
| Average | 6.54% | 5.37% |

The empirical evidence suggests that the common equity risk premium is higher for the S&P Composite Index compared to the S&P Public Utilities.

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations, the results provided on page 2 of Attachment PRM-19 should also be considered. One of these sub-periods included the 54-year period, 1952-2006. These years follow the historic 1951 Treasury-Federal Reserve Accord which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 2006 and 1979 through 2006 contain events subsequent to the initial oil shock and the advent of monetarism as Fed policy, respectively. For the 55-year, 33-year and 28-year periods, the public utility risk premiums were 6.40%, 5.61%, and 5.83% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Attachment PRM-19.

# CAPITAL ASSET PRICING MODEL

Modern portfolio theory provides a theoretical explanation of expected returns on portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium which is proportional to the non-diversifiable (or systematic) risk of a security.

The CAPM theory has several unique assumptions that are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted that found that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Because it is not known whether the average investor holds a well-diversified portfolio, the CAPM must also be used with other models of the cost of equity.

To apply the traditional CAPM theory, three inputs are required: the beta coefficient *("β")*, a risk-free rate of return *("Rf")*, and a market premium *("Rm - Rf")*. The cost of equity stated in terms of the CAPM is:

$$k = Rf + \beta \, (Rm - Rf)$$

As previously indicated, it is important to recognize that the academic research has shown that the security market line was flatter than that predicted by the CAPM theory and it had a higher intercept than the risk-free rate. These tests indicated that for portfolios with betas less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for portfolios with betas above 1.0, these companies had lower returns than indicated by the traditional CAPM theory. Once again, CAPM assumes that through portfolio diversification investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Therefore, the CAPM must also be used with other models of the cost of equity, especially when it is not known whether the average public utility investor holds a well-diversified portfolio.

## Beta

The beta coefficient is a statistical measure which attempts to identify the non-diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of return on a particular security with general market movements. Under the CAPM theory, a security that has a beta of 1.0 should theoretically provide a rate of return equal to the return rate provided by the market. When employing stock price changes in the derivation of beta, a stock with a beta of 1.0 should exhibit a movement in price which would track the movements in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one percent increase in the return on the market will result, on average, in a one percent increase in the return on the particular investment. An investment which has a beta less than 1.0 is considered to be less risky than the market.

The beta coefficient *("$\beta$")*, the one input in the CAPM application which specifically applies to an individual firm, is derived from a statistical application which regresses the returns on an individual security (dependent variable) with the returns on the market as a whole (independent variable). The beta coefficients for utility companies typically describe a small proportion of the total investment risk because the coefficients of determination ($R^2$) are low.

Page 1 of Attachment PRM-20 provides the betas published by Value Line. By way of explanation, the Value Line beta coefficient is derived from a "straight regression" based upon the percentage change in the weekly price of common stock and the percentage change weekly of the New York Stock Exchange Composite average using a five-year period. The raw historical beta is adjusted by Value Line for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the computation of its betas.

**Market Premium**

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return *("Rm - Rf")*. In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is established with forecasts by Value Line using estimated dividend yields and capital appreciation potential.

With regard to the forecast data, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to the January 4, 2008 edition of The Value Line Investment Survey Summary and Index, (see page 5 of Attachment PRM-20) the total return on the universe of Value Line equities is:

| | Dividend Yield | + | Median Appreciation Potential | = | Median Total Return |
|---|---|---|---|---|---|
| As of January 4, 2008 | 1.9% | + | 10.67%[1] | = | 12.57% |

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by Value Line. Another measure of the total market return is provided by the DCF return on the S&P 500 Composite index. As shown below, that return is 13.49%.

DCF Result for the S&P 500 Composite

| D/P | ( | 1+.5g | ) | + | g | = | k |
|---|---|---|---|---|---|---|---|
| 1.88% | ( | 1.05750 | ) | + | 11.50% | = | 13.49% |

| | | | | | |
|---|---|---|---|---|---|
| where: | Price (P) | at | 31-Dec-2007 | = | 1468.36 |
| | Dividend (D) | for | 3rd Qtr. '07 | = | 6.90 |
| | Dividend (D) | | annualized | = | 27.60 |
| | Growth (g) | | First Call EpS | = | 11.50% |

Using these indicators, the total market return is 13.03% (12.57% + 13.49% = 26.06% ÷ 2) using both the Value Line and S&P derived returns. With the 13.03% forecast market return and the 4.75% risk-free rate of return, a 8.28% (13.03% - 4.75%) market premium would be indicated using forecast market data.

1 The estimated median appreciation potential is forecast to be 50% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 10.67% (i.e., $1.50^{.25} - 1$).

With regard to the historical data, I provided the rates of return from long-term historical time periods that have been widely circulated among the investment and academic community over the past several years, as shown on page 6 of Attachment PRM-20. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the data provided on page 6 of Attachment PRM-20, I calculate a market premium using the common stock arithmetic mean returns of 12.3% less government bond arithmetic mean returns of 5.8%. For the period 1926-2006, the market premium was 6.5% (12.3% - 5.8%). I should note that the arithmetic mean must be used in the CAPM because it is a single period model. It is further confirmed by Ibbotson who has indicated:

> *Arithmetic Versus Geometric Differences*
> For use as the expected equity risk premium in the CAPM, the *arithmetic* or *simple difference* of the *arithmetic* means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.
>
> *Arithmetic Versus Geometric Means*
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values. This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154)

For the CAPM, a market premium of 7.39% (6.5% + 8.28% = 14.78% ÷ 2) would be reasonable which is the average of the 6.5% using historical data and a market premium of 8.28% using forecasts.

## COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follow:

### Timeliness Rank

> The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

### Safety Rank

> A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

## Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating an ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

## Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

## Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

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Attachment PRM-11 through 21
National Grid NH
DG 08-009

# ENERGYNORTH NATURAL GAS, INC.
## d/b/a NATIONAL GRID NH

Attachments to

Accompany the

Direct Testimony

of

Paul R. Moul

Concerning
Cost of Capital

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH

Index of Attachments

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Capitalization and Financial Statistics
2002-2006, Inclusive

| | 2006 | 2005 | 2004 (Millions of Dollars) | 2003 | 2002 | Average |
|---|---|---|---|---|---|---|
| Amount of Capital Employed | | | | | | |
| Permanent Capital | $ 120.1 | $ 117.4 | $ 111.6 | $ 146.3 | $ 140.0 | |
| Short-Term Debt | $ 40.2 | $ 53.7 | $ 64.4 | $ 22.7 | $ 3.6 | |
| Total Capital | $ 160.3 | $ 171.2 | $ 176.0 | $ 169.1 | $ 143.6 | |
| Capital Structure Ratios | | | | | | |
| Based on Permanent Captial: | | | | | | |
| Long-Term Debt | 33.3% | 34.1% | 35.8% | 54.8% | 57.6% | 43.1% |
| Common Equity [1] | 66.7% | 65.9% | 64.2% | 45.2% | 42.4% | 56.9% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Based on Total Capital: | | | | | | |
| Total Debt incl. Short Term | 50.0% | 54.8% | 59.3% | 60.9% | 58.6% | 56.7% |
| Common Equity [1] | 50.0% | 45.2% | 40.7% | 39.1% | 41.4% | 43.3% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Rate of Return on Book Common Equity [1] | 3.5% | 7.8% | 8.0% | 9.9% | 3.7% | 6.6% |
| Operating Ratio [2] | 95.6% | 92.6% | 90.1% | 86.7% | 86.0% | 90.2% |
| Coverage incl. AFUDC [3] | | | | | | |
| Pre-tax: All Interest Charges | 2.21 x | 4.00 x | 2.48 x | 3.39 x | 1.24 x | 2.66 x |
| Post-tax: All Interest Charges | 1.81 x | 2.85 x | 1.93 x | 2.19 x | 1.15 x | 1.99 x |
| Coverage excl. AFUDC [3] | | | | | | |
| Pre-tax: All Interest Charges | 2.10 x | 3.94 x | 2.45 x | 3.33 x | 1.21 x | 2.61 x |
| Post-tax: All Interest Charges | 1.70 x | 2.79 x | 1.90 x | 2.14 x | 1.13 x | 1.93 x |
| Quality of Earnings & Cash Flow | | | | | | |
| AFC/Income Avail. for Common Equity | 13.5% | 3.4% | 3.9% | 4.8% | 18.3% | 8.8% |
| Effective Income Tax Rate | 33.2% | 38.2% | 37.1% | 50.1% | 36.1% | 38.9% |
| Internal Cash Generation/Construction [4] | 93.8% | 61.8% | 130.4% | 160.9% | 50.1% | 99.4% |
| Gross Cash Flow/ Avg. Total Debt [5] | 16.7% | 9.8% | 18.5% | 36.2% | 10.7% | 18.4% |
| Gross Cash Flow Interest Coverage [6] | 5.33 x | 4.10 x | 4.24 x | 7.83 x | 2.11 x | 4.72 x |

See Page 2 for Notes.

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Capitalization and Financial Statistics
2002-2006, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account..

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Audited Financial Statements by Deloitte Touche Tohmatsu

Gas Group
Capitalization and Financial Statistics [1]
2002-2006, Inclusive

| | 2006 | 2005 | 2004 | 2003 | 2002 | |
|---|---|---|---|---|---|---|
| | | | (Millions of Dollars) | | | |
| Amount of Capital Employed | | | | | | |
| Permanent Capital | $ 1,900.4 | $ 1,823.5 | $ 1,530.7 | $ 1,233.7 | $ 1,136.9 | |
| Short-Term Debt | $ 263.5 | $ 187.8 | $ 141.9 | $ 218.6 | $ 138.3 | |
| Total Capital | $ 2,163.9 | $ 2,011.3 | $ 1,672.6 | $ 1,452.3 | $ 1,275.2 | |
| Market-Based Financial Ratios | | | | | | Average |
| Price-Earnings Multiple | 16 x | 16 x | 15 x | 14 x | 17 x | 16 x |
| Market/Book Ratio | 192.9% | 198.4% | 187.4% | 180.9% | 170.3% | 186.0% |
| Dividend Yield | 3.7% | 3.7% | 4.0% | 4.5% | 4.9% | 4.2% |
| Dividend Payout Ratio | 59.4% | 59.6% | 61.4% | 61.5% | 82.4% | 64.9% |
| Capital Structure Ratios | | | | | | |
| Based on Permanent Capital: | | | | | | |
| Long-Term Debt | 46.4% | 46.1% | 45.7% | 46.7% | 51.1% | 47.2% |
| Preferred Stock | 0.5% | 0.4% | 0.5% | 0.3% | 0.4% | 0.4% |
| Common Equity [2] | 53.2% | 53.5% | 53.8% | 53.0% | 48.5% | 52.4% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Based on Total Capital: | | | | | | |
| Total Debt incl. Short Term | 53.8% | 51.9% | 50.9% | 55.2% | 56.1% | 53.6% |
| Preferred Stock | 0.4% | 0.4% | 0.4% | 0.3% | 0.4% | 0.4% |
| Common Equity [2] | 45.8% | 47.7% | 48.7% | 44.5% | 43.4% | 46.0% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Rate of Return on Book Common Equity [2] | 12.4% | 12.2% | 12.1% | 13.0% | 11.0% | 12.1% |
| Operating Ratio [3] | 89.1% | 89.1% | 88.1% | 86.7% | 84.9% | 87.6% |
| Coverage incl. AFUDC [4] | | | | | | |
| Pre-tax: All Interest Charges | 4.14 x | 4.43 x | 4.61 x | 4.44 x | 3.47 x | 4.22 x |
| Post-tax: All Interest Charges | 2.92 x | 3.11 x | 3.22 x | 3.11 x | 2.51 x | 2.97 x |
| Overall Coverage: All Int. & Pfd. Div. | 2.91 x | 3.10 x | 3.21 x | 3.10 x | 2.49 x | 2.96 x |
| Coverage excl. AFUDC [4] | | | | | | |
| Pre-tax: All Interest Charges | 4.11 x | 4.41 x | 4.59 x | 4.42 x | 3.45 x | 4.20 x |
| Post-tax: All Interest Charges | 2.89 x | 3.10 x | 3.20 x | 3.09 x | 2.49 x | 2.95 x |
| Overall Coverage: All Int. & Pfd. Div. | 2.88 x | 3.08 x | 3.19 x | 3.08 x | 2.47 x | 2.94 x |
| Quality of Earnings & Cash Flow | | | | | | |
| AFC/Income Avail. for Common Equity | 1.8% | 0.9% | 1.2% | 1.2% | 1.4% | 1.3% |
| Effective Income Tax Rate | 38.5% | 38.1% | 38.0% | 38.1% | 38.7% | 38.3% |
| Internal Cash Generation/Construction [5] | 78.0% | 84.6% | 94.4% | 120.4% | 82.9% | 92.1% |
| Gross Cash Flow/ Avg. Total Debt [6] | 18.9% | 20.3% | 22.0% | 22.6% | 18.2% | 20.4% |
| Gross Cash Flow Interest Coverage [7] | 4.15 x | 4.53 x | 5.28 x | 5.32 x | 4.08 x | 4.67 x |
| Common Dividend Coverage [8] | 3.10 x | 3.06 x | 3.50 x | 3.71 x | 3.16 x | 3.31 x |

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2002-2006, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Gas Group includes companies that (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey, (iv) they have not recently cut or omitted their dividend, (v) they are not currently the target of a merger or acquisition, (vi) they operate with weather normalization and/or decoupling tariff features, and (vii) they have at least 60% of their assets subject to utility regulation.

| | | Corporate Credit Ratings | | Stock | S&P Stock | Value Line |
|---|---|---|---|---|---|---|
| Ticker | Company | Moody's | S&P | Traded | Ranking | Beta |
| ATG | AGL Resources, Inc. | A3 | A- | NYSE | A- | 0.85 |
| ATO | Atmos Energy Corp. | Baa3 | BBB | NYSE | B+ | 0.85 |
| NJR | New Jersey Resources Corp | Aa3 | A+ | NYSE | A | 0.85 |
| NWN | Northwest Natural Gas | A3 | AA- | NYSE | B+ | 0.90 |
| PNY | Piedmont Natural Gas Co. | A3 | A | NYSE | A- | 0.85 |
| SJI | South Jersey Industries, Inc. | Baa2 | BBB+ | NYSE | B+ | 0.85 |
| WGL | WGL Holdings, Inc. | A2 | AA- | NYSE | B+ | 0.85 |
| | Average | A3 | A | | B+ | 0.86 |

Note: Ratings are those of utility subsidiaries

Source of Information: Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation
S&P Stock Guide

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2002-2006, Inclusive

| | 2006 | 2005 | 2004 (Millions of Dollars) | 2003 | 2002 | Average |
|---|---|---|---|---|---|---|
| Amount of Capital Employed | | | | | | |
| Permanent Capital | $ 15,146.0 | $ 14,261.2 | $ 14,164.3 | $ 14,259.5 | $ 13,850.0 | |
| Short-Term Debt | $ 516.4 | $ 480.8 | $ 279.5 | $ 266.9 | $ 913.6 | |
| Total Capital | $ 15,662.4 | $ 14,742.0 | $ 14,443.8 | $ 14,526.4 | $ 14,763.6 | |
| Market-Based Financial Ratios | | | | | | |
| Price-Earnings Multiple | 16 x | 16 x | 15 x | 13 x | 14 x | 15 x |
| Market/Book Ratio | 206.6% | 201.8% | 182.4% | 150.6% | 152.2% | 178.7% |
| Dividend Yield | 3.5% | 3.5% | 3.8% | 4.2% | 5.0% | 4.0% |
| Dividend Payout Ratio | 56.3% | 57.2% | 70.3% | 58.8% | 72.8% | 63.1% |
| Capital Structure Ratios | | | | | | |
| Based on Permanent Captial: | | | | | | |
| Long-Term Debt | 54.1% | 55.6% | 57.4% | 59.3% | 60.4% | 57.4% |
| Preferred Stock | 1.1% | 1.3% | 1.5% | 1.6% | 1.8% | 1.5% |
| Common Equity [2] | 44.7% | 43.2% | 41.0% | 39.1% | 37.8% | 41.2% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Based on Total Capital: | | | | | | |
| Total Debt incl. Short Term | 56.1% | 57.7% | 59.0% | 60.7% | 63.1% | 59.3% |
| Preferred Stock | 1.1% | 1.2% | 1.5% | 1.6% | 1.7% | 1.4% |
| Common Equity [2] | 42.8% | 41.1% | 39.5% | 37.7% | 35.2% | 39.3% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Rate of Return on Book Common Equity [2] | 12.3% | 11.4% | 11.5% | 10.0% | 8.1% | 10.7% |
| Operating Ratio [3] | 81.2% | 85.2% | 84.4% | 84.8% | 84.5% | 84.0% |
| Coverage incl. AFUDC [4] | | | | | | |
| Pre-tax: All Interest Charges | 3.42 x | 3.20 x | 3.02 x | 2.57 x | 2.41 x | 2.92 x |
| Post-tax: All Interest Charges | 2.64 x | 2.54 x | 2.42 x | 2.12 x | 1.99 x | 2.34 x |
| Overall Coverage: All Int. & Pfd. Div. | 2.61 x | 2.50 x | 2.38 x | 2.07 x | 1.95 x | 2.30 x |
| Coverage excl. AFUDC [4] | | | | | | |
| Pre-tax: All Interest Charges | 3.38 x | 3.17 x | 2.99 x | 2.53 x | 2.37 x | 2.89 x |
| Post-tax: All Interest Charges | 2.60 x | 2.51 x | 2.39 x | 2.08 x | 1.95 x | 2.31 x |
| Overall Coverage: All Int. & Pfd. Div. | 2.56 x | 2.47 x | 2.35 x | 2.03 x | 1.90 x | 2.26 x |
| Quality of Earnings & Cash Flow | | | | | | |
| AFC/Income Avail. for Common Equity | 2.4% | 0.9% | 3.0% | 1.7% | 2.6% | 2.1% |
| Effective Income Tax Rate | 32.4% | 31.3% | 26.2% | 40.3% | 29.0% | 31.8% |
| Internal Cash Generation/Construction [5] | 95.6% | 106.3% | 127.0% | 127.8% | 91.6% | 110.1% |
| Gross Cash Flow/ Avg. Total Debt [6] | 23.8% | 21.3% | 21.1% | 20.8% | 19.0% | 21.2% |
| Gross Cash Flow Interest Coverage [7] | 4.57 x | 4.42 x | 4.42 x | 4.42 x | 4.07 x | 4.38 x |
| Common Dividend Coverage [8] | 4.41 x | 4.41 x | 5.00 x | 5.27 x | 4.23 x | 4.66 x |

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2002-2006, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

**Standard & Poor's Public Utilities**

Company Identities [1]

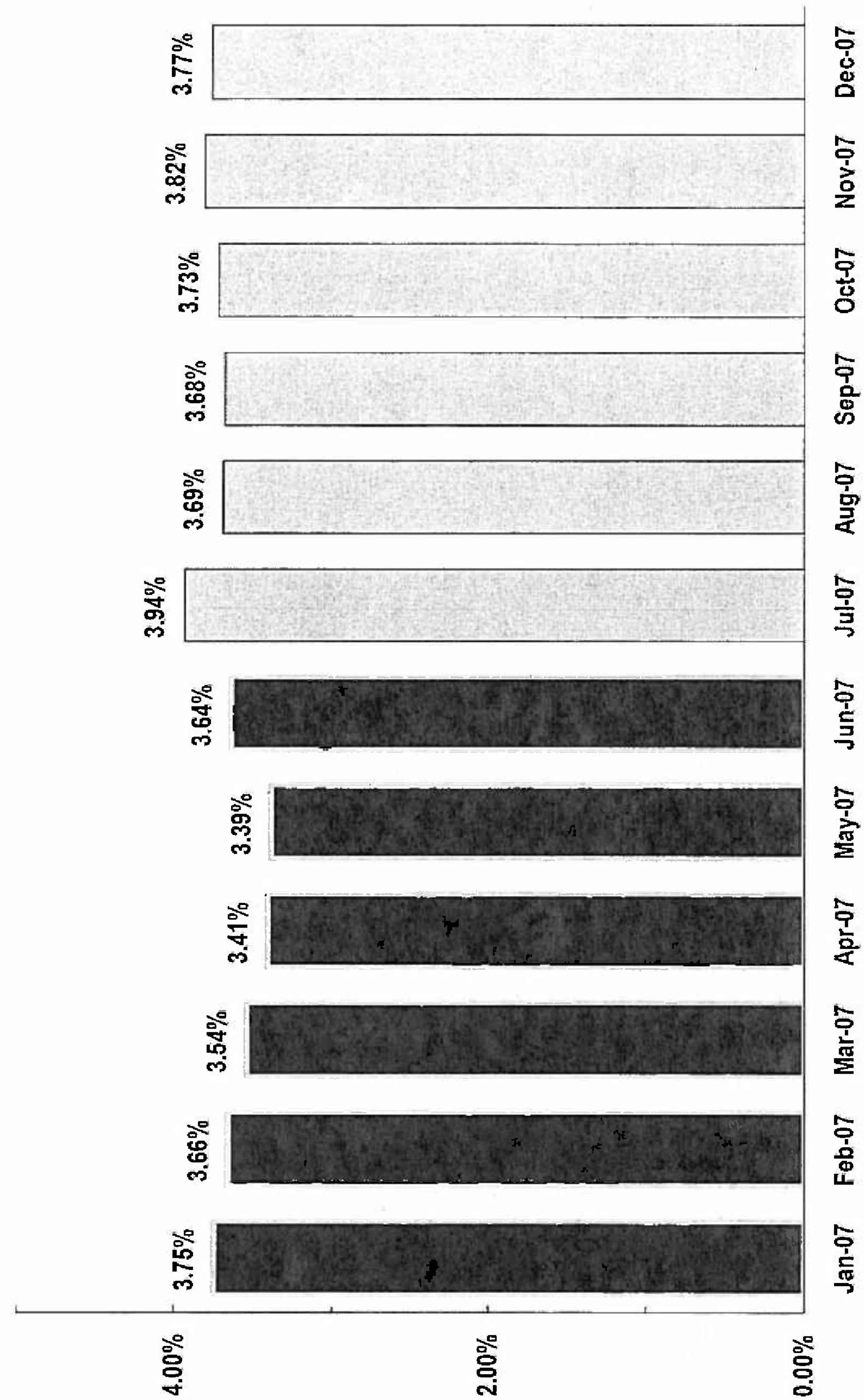
| | Ticker | Credit Rating [2] Moody's | S&P | Common Stock Traded | S&P Stock Ranking | Value Line Beta |
|---|---|---|---|---|---|---|
| Allegheny Energy | AYE | Baa3 | BB+ | NYSE | B- | 1.85 |
| Ameren Corporation | AEE | A2 | BBB+ | NYSE | A- | 0.75 |
| American Electric Power | AEP | Baa2 | BBB | NYSE | B | 1.20 |
| CMS Energy | CMS | Ba1 | BB | NYSE | C | 1.45 |
| CenterPoint Energy | CNP | Baa3 | BBB | NYSE | B | 0.65 |
| Consolidated Edison | ED | A1 | A | NYSE | B+ | 0.65 |
| Constellation Energy Group | CEG | A3 | BBB+ | NYSE | B | 0.95 |
| DTE Energy Co. | DTE | Baa1 | BBB | NYSE | B+ | 0.70 |
| Dominion Resources | D | Baa1 | BBB | NYSE | B+ | 0.95 |
| Duke Energy | DUK | Baa2 | BBB | NYSE | B+ | 1.20 |
| Edison Int'l | EIX | Baa1 | BBB+ | NYSE | B | 1.05 |
| Entergy Corp. | ETR | Baa2 | BBB | NYSE | B+ | 0.85 |
| Exelon Corp. | EXC | A3 | BBB+ | NYSE | B+ | 0.80 |
| FPL Group | FPL | A1 | A | NYSE | A- | 0.80 |
| FirstEnergy Corp. | FE | Baa2 | BBB | NYSE | B+ | 0.75 |
| Integrys Energy Group | TEG | A1 | A- | NYSE | B | 0.85 |
| Keyspan Energy | KSE | A3 | A | NYSE | B | 0.85 |
| NICOR Inc. | GAS | A1 | AA | NYSE | B | 1.15 |
| NiSource Inc. | NI | Baa2 | BBB | NYSE | B | 0.80 |
| PG&E Corp. | PCG | Baa1 | BBB | NYSE | B | 1.10 |
| PPL Corp. | PPL | Baa1 | A- | NYSE | B | 1.00 |
| Pinnacle West Capital | PNW | Baa2 | BBB- | NYSE | A- | 0.90 |
| Progress Energy, Inc. | PGN | Baa1 | BBB | NYSE | B+ | 0.80 |
| Public Serv. Enterprise Inc. | PEG | Baa1 | BBB | NYSE | B+ | 0.90 |
| Questar Corp. | STR | A2 | A- | NYSE | A- | 0.90 |
| Sempra Energy | SRE | A2 | A | NYSE | B | 1.00 |
| Southern Co. | SO | A2 | A | NYSE | A- | 0.65 |
| TECO Energy | TE | Baa2 | BBB- | NYSE | B- | 1.00 |
| TXU CORP | TXU | Baa3 | BBB- | NYSE | B | 1.05 |
| Xcel Energy Inc | XEL | A3 | BBB+ | NYSE | B | 0.80 |
| Average for S&P Utilities | | Baa1 | BBB+ | | B | 0.95 |

Note: [1] Includes companies contained in S&P Utility Compustat. AES Corp. and Dynegy, Inc. are not included.

[2] Ratings are those of utility subsidiaries

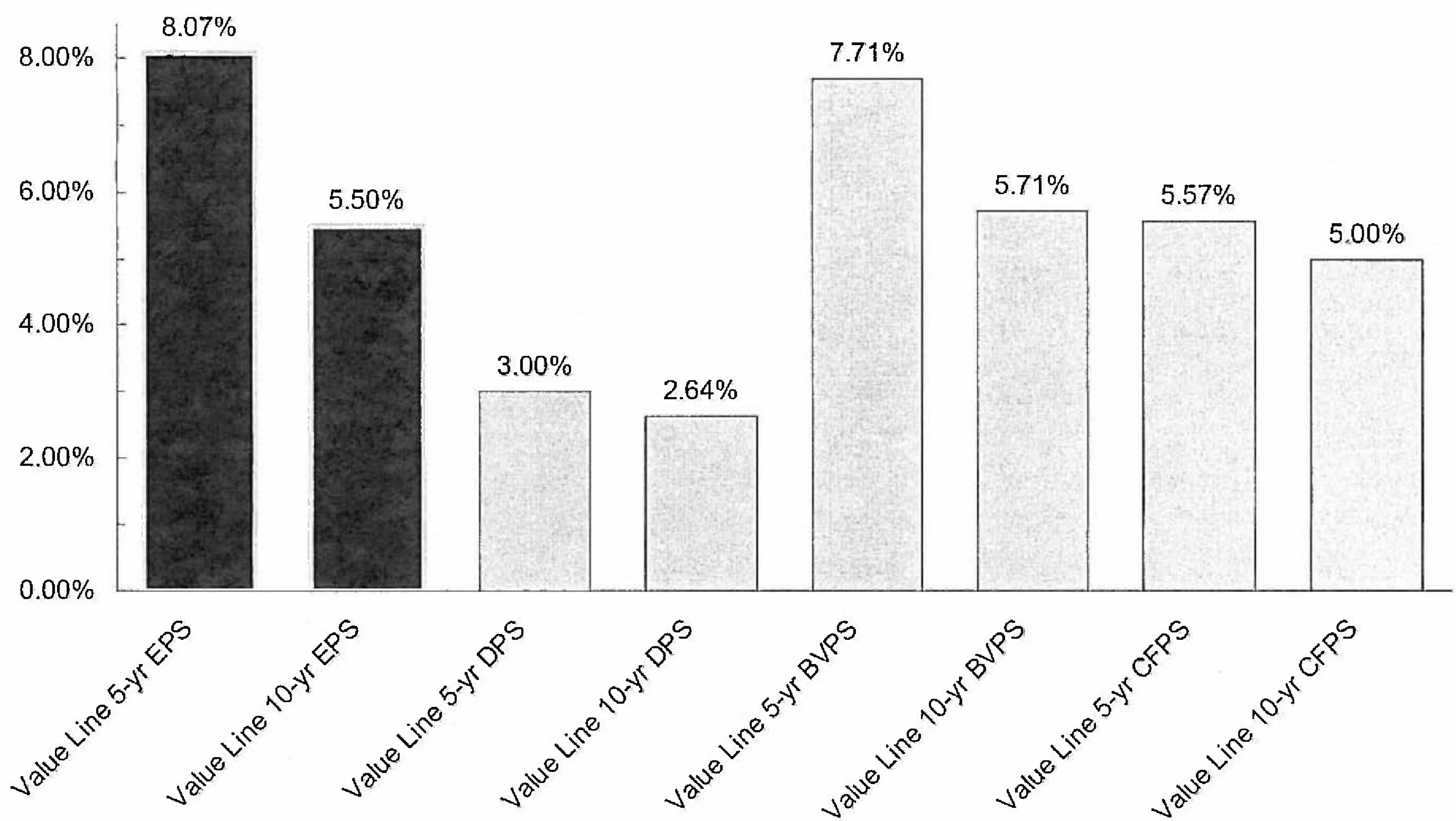
Source of Information: Moody's Investors Service
Standard & Poor's Corporation
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

# Gas Group
## Monthly Dividend Yields



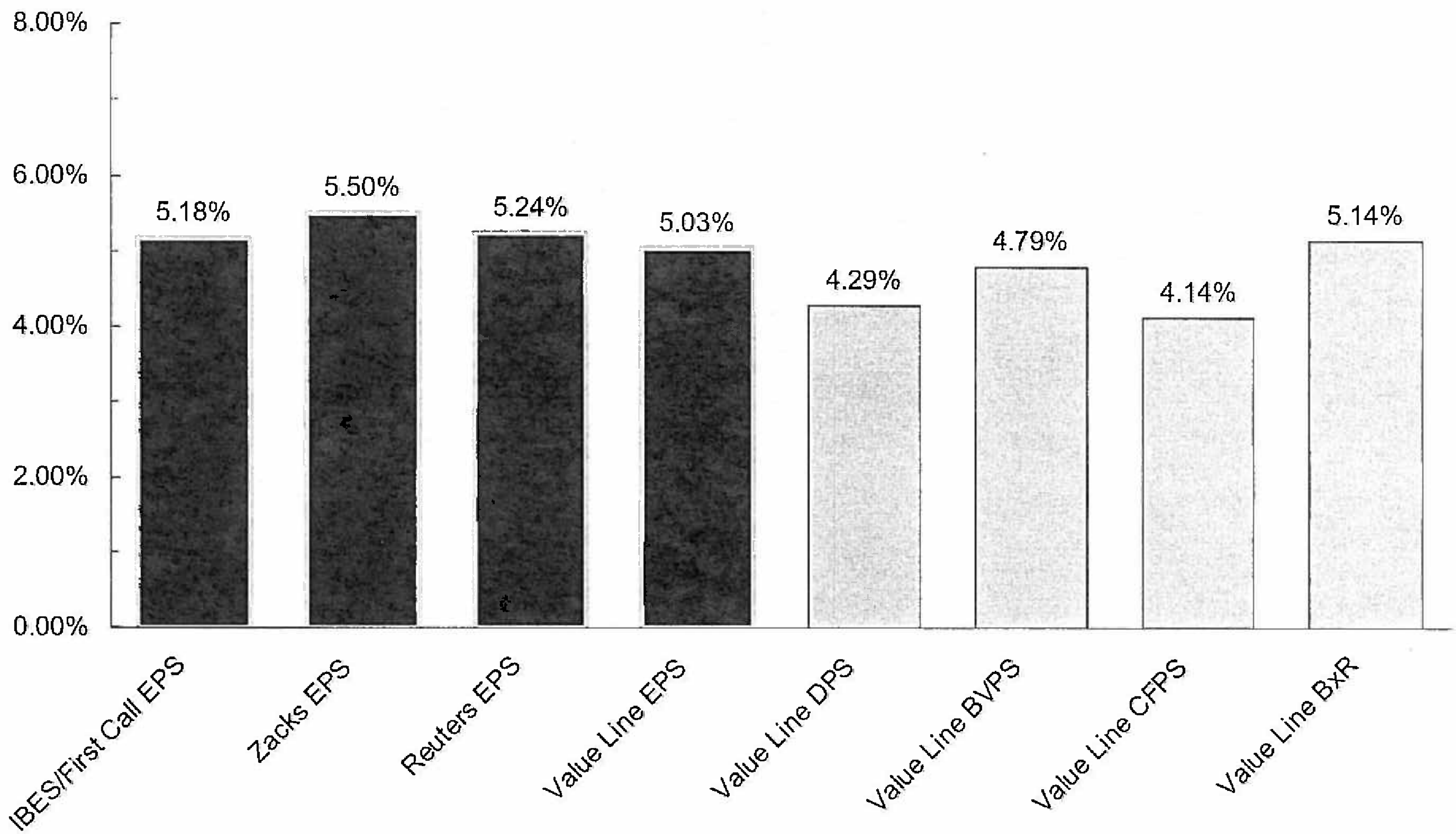
# Gas Group

## Historical Growth Rates




Earnings per Share=EPS Book Values per Share=BVPS
Dividends per Share=DPS Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

# Gas Group
## Five-Year Projected Growth Rates




Earnings per Share=EPS
Dividends per Share=DPS
Book Values per Share=BVPS
Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

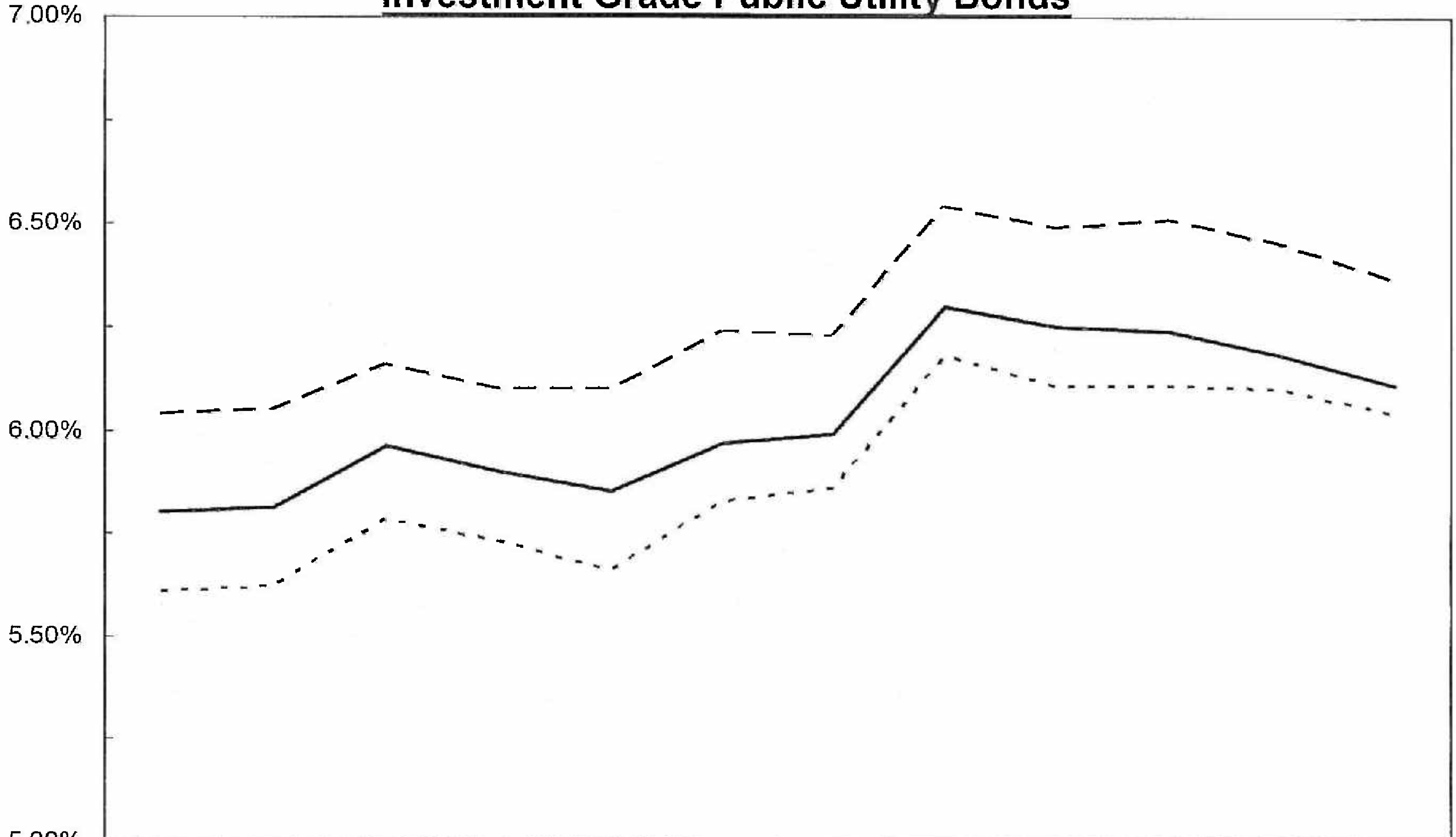
**Natural Gas Industry**
Analysis of Public Offerings of Common Stock
Years 2002-2006

| | UTILICORP | MDU Resources | AGL RESOURCES | SOUTHERN UNION CO. | ATMOS ENERGY | VECTREN CORP. | SEMPRA ENERGY | PIEDMONT NATURAL | UGI CORP. |
|---|---|---|---|---|---|---|---|---|---|
| Date of Offering | 1/25/2002 | 11/29/2002 | 2/11/2003 | 6/5/2003 | 6/18/2003 | 8/7/2003 | 10/8/2003 | 1/20/2004 | 3/18/2004 |
| No. of shares offered (000) | 11,000 | 2,100 | 5,600 | 9,500 | 4,000 | 6,500 | 15,000 | 4,250 | 7,500 |
| Dollar amt. of offering ($000) | $ 253,000 | $ 50,400 | $ 123,200 | $ 152,000 | $ 101,240 | $ 148,265 | $ 420,000 | $ 180,625 | $ 240,750 |
| Price to public | $ 23.000 | $ 24.200 | $ 22.000 | $ 16.000 | $ 25.310 | $ 22.810 | $ 28.000 | $ 42.500 | $ 32.100 |
| Underwriter's discounts and commission | $ 0.748 | $ 0.720 | $ 0.770 | $ 0.560 | $ 1.013 | $ 0.798 | $ 0.840 | $ 1.490 | $ 1.404 |
| Gross Proceeds | $ 22.252 | $ 23.480 | $ 21.230 | $ 15.440 | $ 24.297 | $ 22.012 | $ 27.160 | $ 41.010 | $ 30.696 |
| Estimated company issuance expenses | NA | $ 0.092 | $ 0.045 | $ 0.089 | $ 0.095 | $ 0.046 | $ 0.033 | NA | $ 0.020 |
| Net proceeds to company per share | $ 22.252 | $ 23.388 | $ 21.185 | $ 15.351 | $ 24.202 | $ 21.966 | $ 27.127 | $ 41.010 | $ 30.676 |
| Underwriter's discount as a percent of offering price | 3.3% | 3.0% | 3.5% | 3.5% | 4.0% | 3.5% | 3.0% | 3.5% | 4.4% |
| Issuance expense as a percent of offering price | NA | 0.4% | 0.2% | 0.6% | 0.4% | 0.2% | 0.1% | NA | 0.1% |
| Total Issuance and selling expense as as a percent of offering price | 3.3% | 3.4% | 3.7% | 4.1% | 4.4% | 3.7% | 3.1% | 3.5% | 4.5% |

| | NORTHWEST NATURAL | LACLEDE GROUP | SOUTHERN UNION CO | AQUILA | ATMOS ENERGY | AGL RESOURCES | SOUTHERN UNION CO. | SEMCO Energy | Chesapeake Utilities | Average |
|---|---|---|---|---|---|---|---|---|---|---|
| Date of Offering | 3/30/2004 | 5/6/2004 | 7/26/2004 | 8/18/2004 | 10/21/2004 | 11/19/2004 | 2/7/2005 | 8/9/2005 | 11/15/2006 | |
| No. of shares offered (000) | 1,200 | 1,500 | 11,000 | 40,000 | 14,000 | 9,600 | 14,913 | 4,300 | 600.3 | |
| Dollar amt. of offering ($000) | $ 37,200 | $ 40,200 | $ 206,250 | $ 102,000 | $ 346,500 | $ 297,696 | $ 342,999 | $ 27,176 | $ 18,069 | |
| Price to public | $ 31.000 | $ 26.800 | $ 18.750 | $ 2.550 | $ 24.750 | $ 31.010 | $ 23.000 | $ 6.320 | $ 30.100 | |
| Underwriter's discounts and commission | $ 1.010 | $ 0.871 | $ 0.656 | $ 0.099 | $ 0.990 | $ 0.930 | $ 0.700 | $ 0.253 | $ 1.125 | |
| Gross Proceeds | $ 29.990 | $ 25.929 | $ 18.094 | $ 2.451 | $ 23.760 | $ 30.080 | $ 22.300 | $ 6.067 | $ 28.975 | |
| Estimated company issuance expenses | $ 0.146 | $ 0.067 | $ 0.091 | NA | NA | $ 0.042 | $ 0.067 | $ 0.070 | $ 0.375 | |
| Net proceeds to company per share | $ 29.844 | $ 25.862 | $ 18.003 | $ 2.451 | $ 23.760 | $ 30.038 | $ 22.233 | $ 5.997 | $ 28.600 | |
| Underwriter's discount as a percent of offering price | 3.3% | 3.3% | 3.5% | 3.9% | 4.0% | 3.0% | 3.0% | 4.0% | 3.7% | 3.5% |
| Issuance expense as a percent of offering price | 0.5% | 0.3% | 0.5% | NA | NA | 0.1% | 0.3% | 1.1% | 1.2% | 0.4% |
| Total Issuance and selling expense as as a percent of offering price | 3.8% | 3.6% | 4.0% | 3.9% | 4.0% | 3.1% | 3.3% | 5.1% | 4.9% | 3.9% |

Source of information. Public Utility Financial Tracker

# Interest Rates for Investment Grade Public Utility Bonds



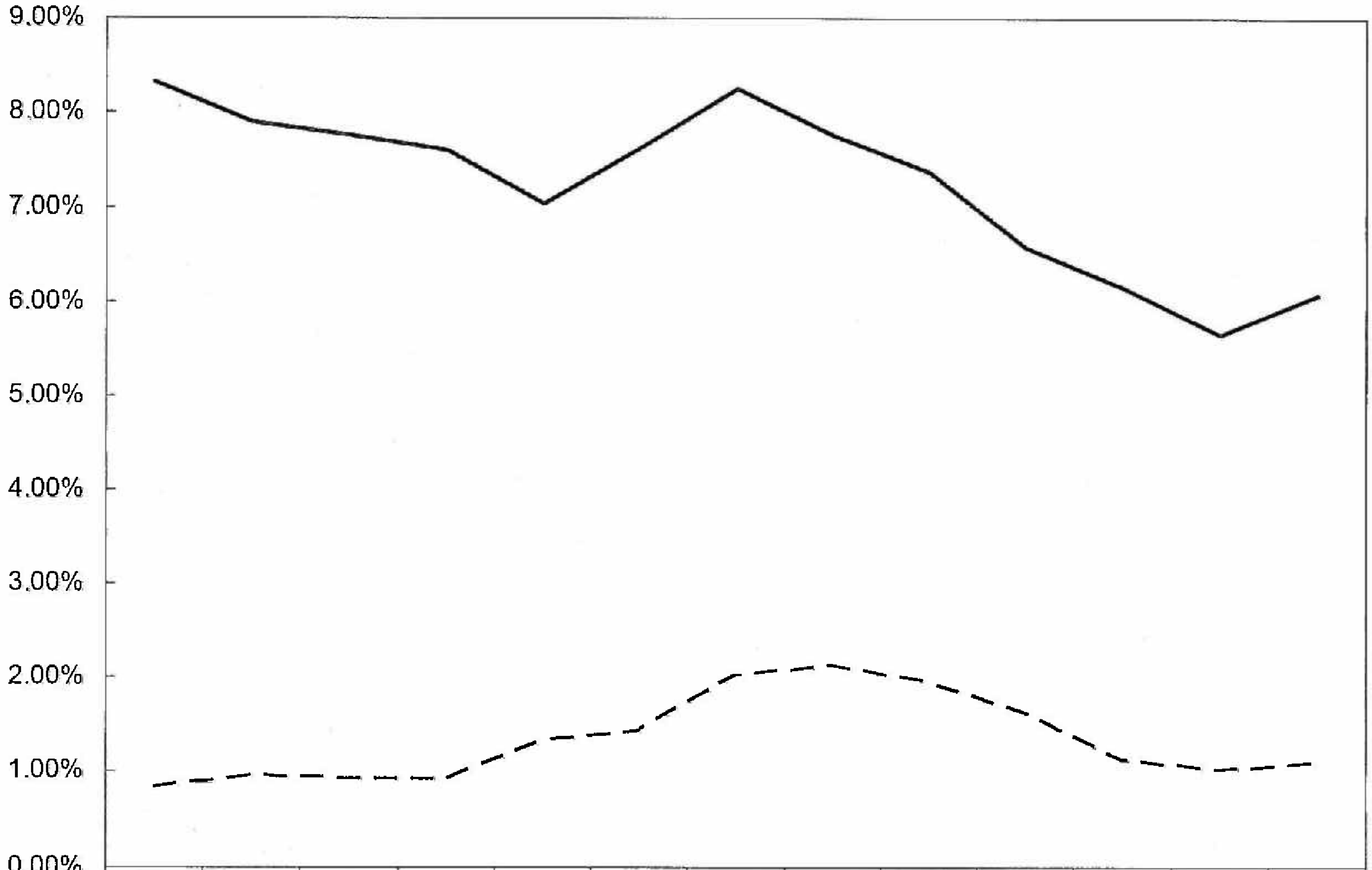

| | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Jul-07 | Aug-07 | Sep-07 | Oct-07 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Aa | 5.61% | 5.62% | 5.78% | 5.73% | 5.66% | 5.83% | 5.86% | 6.18% | 6.11% | 6.11% | 6.10% | 6.04% |
| A | 5.80% | 5.81% | 5.96% | 5.90% | 5.85% | 5.97% | 5.99% | 6.30% | 6.25% | 6.24% | 6.18% | 6.11% |
| Baa | 6.04% | 6.05% | 6.16% | 6.10% | 6.10% | 6.24% | 6.23% | 6.54% | 6.49% | 6.51% | 6.45% | 6.36% |

## Interest Rates for Investment Grade Public Utility Bonds
## Yearly for 2001-2006
## and the Twelve Months Ended October 2007

| Years | Aa Rated | A Rated | Baa Rated | Average |
|---|---|---|---|---|
| 2002 | 7.19% | 7.37% | 8.02% | 7.53% |
| 2003 | 6.40% | 6.58% | 6.84% | 6.61% |
| 2004 | 6.04% | 6.16% | 6.40% | 6.20% |
| 2005 | 5.44% | 5.65% | 5.93% | 5.67% |
| 2006 | 5.84% | 6.07% | 6.32% | 6.08% |
| Five-Year Average | 6.18% | 6.37% | 6.70% | 6.42% |
| **Months** | | | | |
| Nov-06 | 5.61% | 5.80% | 6.04% | 5.82% |
| Dec-06 | 5.62% | 5.81% | 6.05% | 5.83% |
| Jan-07 | 5.78% | 5.96% | 6.16% | 5.96% |
| Feb-07 | 5.73% | 5.90% | 6.10% | 5.91% |
| Mar-07 | 5.66% | 5.85% | 6.10% | 5.87% |
| Apr-07 | 5.83% | 5.97% | 6.24% | 6.01% |
| May-07 | 5.86% | 5.99% | 6.23% | 6.03% |
| Jun-07 | 6.18% | 6.30% | 6.54% | 6.34% |
| Jul-07 | 6.11% | 6.25% | 6.49% | 6.28% |
| Aug-07 | 6.11% | 6.24% | 6.51% | 6.28% |
| Sep-07 | 6.10% | 6.18% | 6.45% | 6.24% |
| Oct-07 | 6.04% | 6.11% | 6.36% | 6.17% |
| Twelve-Month Average | 5.89% | 6.03% | 6.27% | 6.06% |
| Six-Month Average | 6.07% | 6.18% | 6.43% | 6.22% |
| Three-Month Average | 6.08% | 6.18% | 6.44% | 6.23% |

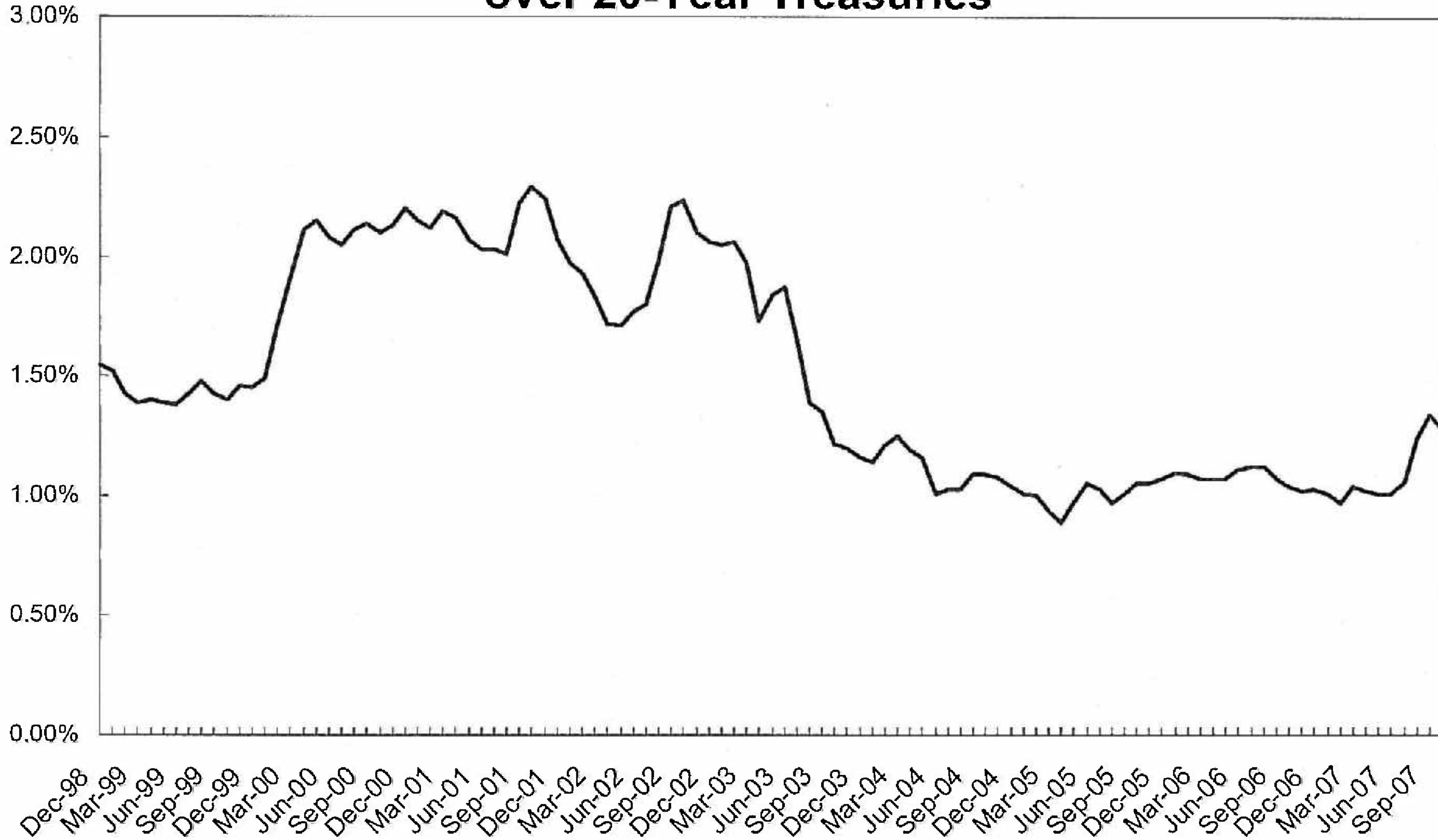
Source: Mergent Bond Record

# Yields on A-rated Public Utility Bonds and Spreads over 20-Year Treasuries




| | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A-rated Public Utility | 8.31% | 7.89% | 7.75% | 7.60% | 7.04% | 7.62% | 8.24% | 7.76% | 7.37% | 6.58% | 6.16% | 5.65% | 6.07% |
| Spread vs. 20-year | 0.82% | 0.94% | 0.92% | 0.91% | 1.32% | 1.42% | 2.01% | 2.13% | 1.94% | 1.62% | 1.12% | 1.01% | 1.08% |

## Interest Rate Spreads
## A-rated Public Utility Bonds
## over 20-Year Treasuries



A rated Public Utility Bonds
over 20-Year Treasuries

| Year | A-rated Public Utility | 20-Year Treasuries Yield | 20-Year Treasuries Spread |
|---|---|---|---|
| Dec-98 | 6.91% | 5.36% | 1.55% |
| Jan-99 | 6.97% | 5.45% | 1.52% |
| Feb-99 | 7.09% | 5.66% | 1.43% |
| Mar-99 | 7.26% | 5.87% | 1.39% |
| Apr-99 | 7.22% | 5.82% | 1.40% |
| May-99 | 7.47% | 6.08% | 1.39% |
| Jun-99 | 7.74% | 6.36% | 1.38% |
| Jul-99 | 7.71% | 6.28% | 1.43% |
| Aug-99 | 7.91% | 6.43% | 1.48% |
| Sep-99 | 7.93% | 6.50% | 1.43% |
| Oct-99 | 8.06% | 6.66% | 1.40% |
| Nov-99 | 7.94% | 6.48% | 1.46% |
| Dec-99 | 8.14% | 6.69% | 1.45% |
| Jan-00 | 8.35% | 6.86% | 1.49% |
| Feb-00 | 8.25% | 6.54% | 1.71% |
| Mar-00 | 8.28% | 6.38% | 1.90% |
| Apr-00 | 8.29% | 6.18% | 2.11% |
| May-00 | 8.70% | 6.55% | 2.15% |
| Jun-00 | 8.36% | 6.28% | 2.08% |
| Jul-00 | 8.25% | 6.20% | 2.05% |
| Aug-00 | 8.13% | 6.02% | 2.11% |
| Sep-00 | 8.23% | 6.09% | 2.14% |
| Oct-00 | 8.14% | 6.04% | 2.10% |
| Nov-00 | 8.11% | 5.98% | 2.13% |
| Dec-00 | 7.84% | 5.64% | 2.20% |
| Jan-01 | 7.80% | 5.65% | 2.15% |
| Feb-01 | 7.74% | 5.62% | 2.12% |
| Mar-01 | 7.68% | 5.49% | 2.19% |
| Apr-01 | 7.94% | 5.78% | 2.16% |
| May-01 | 7.99% | 5.92% | 2.07% |
| Jun-01 | 7.85% | 5.82% | 2.03% |
| Jul-01 | 7.78% | 5.75% | 2.03% |
| Aug-01 | 7.59% | 5.58% | 2.01% |
| Sep-01 | 7.75% | 5.53% | 2.22% |
| Oct-01 | 7.63% | 5.34% | 2.29% |
| Nov-01 | 7.57% | 5.33% | 2.24% |
| Dec-01 | 7.83% | 5.76% | 2.07% |
| Jan-02 | 7.66% | 5.69% | 1.97% |
| Feb-02 | 7.54% | 5.61% | 1.93% |
| Mar-02 | 7.76% | 5.93% | 1.83% |
| Apr-02 | 7.57% | 5.85% | 1.72% |
| May-02 | 7.52% | 5.81% | 1.71% |
| Jun-02 | 7.42% | 5.65% | 1.77% |
| Jul-02 | 7.31% | 5.51% | 1.80% |
| Aug-02 | 7.17% | 5.19% | 1.98% |
| Sep-02 | 7.08% | 4.87% | 2.21% |
| Oct-02 | 7.23% | 5.00% | 2.23% |
| Nov-02 | 7.14% | 5.04% | 2.10% |
| Dec-02 | 7.07% | 5.01% | 2.06% |
| Jan-03 | 7.07% | 5.02% | 2.05% |
| Feb-03 | 6.93% | 4.87% | 2.06% |
| Mar-03 | 6.79% | 4.82% | 1.97% |
| Apr-03 | 6.64% | 4.91% | 1.73% |
| May-03 | 6.36% | 4.52% | 1.84% |
| Jun-03 | 6.21% | 4.34% | 1.87% |
| Jul-03 | 6.57% | 4.92% | 1.65% |
| Aug-03 | 6.78% | 5.39% | 1.39% |
| Sep-03 | 6.56% | 5.21% | 1.35% |
| Oct-03 | 6.43% | 5.21% | 1.22% |
| Nov-03 | 6.37% | 5.17% | 1.20% |
| Dec-03 | 6.27% | 5.11% | 1.16% |
| Jan-04 | 6.15% | 5.01% | 1.14% |
| Feb-04 | 6.15% | 4.94% | 1.21% |
| Mar-04 | 5.97% | 4.72% | 1.25% |
| Apr-04 | 6.35% | 5.16% | 1.19% |
| May-04 | 6.62% | 5.46% | 1.16% |
| Jun-04 | 6.46% | 5.45% | 1.01% |
| Jul-04 | 6.27% | 5.24% | 1.03% |
| Aug-04 | 6.14% | 5.07% | 1.07% |
| Sep-04 | 5.98% | 4.89% | 1.09% |
| Oct-04 | 5.94% | 4.85% | 1.09% |
| Nov-04 | 5.97% | 4.89% | 1.08% |
| Dec-04 | 5.92% | 4.88% | 1.04% |
| Jan-05 | 5.78% | 4.77% | 1.01% |
| Feb-05 | 5.61% | 4.61% | 1.00% |
| Mar-05 | 5.83% | 4.89% | 0.94% |
| Apr-05 | 5.64% | 4.75% | 0.89% |
| May-05 | 5.53% | 4.56% | 0.97% |
| Jun-05 | 5.40% | 4.35% | 1.05% |
| Jul-05 | 5.51% | 4.48% | 1.03% |
| Aug-05 | 5.50% | 4.53% | 0.97% |
| Sep-05 | 5.52% | 4.51% | 1.01% |
| Oct-05 | 5.79% | 4.74% | 1.05% |
| Nov-05 | 5.88% | 4.83% | 1.05% |
| Dec-05 | 5.80% | 4.73% | 1.07% |
| Jan-06 | 5.75% | 4.65% | 1.10% |
| Feb-06 | 5.82% | 4.73% | 1.09% |
| Mar-06 | 5.98% | 4.91% | 1.07% |
| Apr-06 | 6.29% | 5.22% | 1.07% |
| May-06 | 6.42% | 5.35% | 1.07% |
| Jun-06 | 6.40% | 5.29% | 1.11% |
| Jul-06 | 6.37% | 5.25% | 1.12% |
| Aug-06 | 6.20% | 5.08% | 1.12% |
| Sep-06 | 6.00% | 4.93% | 1.07% |
| Oct-06 | 5.98% | 4.94% | 1.04% |
| Nov-06 | 5.80% | 4.78% | 1.02% |
| Dec-06 | 5.81% | 4.78% | 1.03% |
| Jan-07 | 5.96% | 4.95% | 1.01% |
| Feb-07 | 5.90% | 4.93% | 0.97% |
| Mar-07 | 5.85% | 4.81% | 1.04% |
| Apr-07 | 5.97% | 4.95% | 1.02% |
| May-07 | 5.99% | 4.98% | 1.01% |
| Jun-07 | 6.30% | 5.29% | 1.01% |
| Jul-07 | 6.25% | 5.19% | 1.06% |
| Aug-07 | 6.24% | 5.00% | 1.24% |
| Sep-07 | 6.18% | 4.84% | 1.34% |
| Oct-07 | 6.11% | 4.83% | 1.28% |

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-2006

| Year | S & P Composite Index | S & P Public Utility Index | Long Term Corporate Bonds | Public Utility Bonds |
|---|---|---|---|---|
| 1928 | 43.61% | 57.47% | 2.84% | 3.08% |
| 1929 | -8.42% | 11.02% | 3.27% | 2.34% |
| 1930 | -24.90% | -21.96% | 7.98% | 4.74% |
| 1931 | -43.34% | -35.90% | -1.85% | -11.11% |
| 1932 | -8.19% | -0.54% | 10.82% | 7.25% |
| 1933 | 53.99% | -21.87% | 10.38% | -3.82% |
| 1934 | -1.44% | -20.41% | 13.84% | 22.61% |
| 1935 | 47.67% | 76.63% | 9.61% | 16.03% |
| 1936 | 33.92% | 20.69% | 6.74% | 8.30% |
| 1937 | -35.03% | -37.04% | 2.75% | -4.05% |
| 1938 | 31.12% | 22.45% | 6.13% | 8.11% |
| 1939 | -0.41% | 11.26% | 3.97% | 6.76% |
| 1940 | -9.78% | -17.15% | 3.39% | 4.45% |
| 1941 | -11.59% | -31.57% | 2.73% | 2.15% |
| 1942 | 20.34% | 15.39% | 2.60% | 3.81% |
| 1943 | 25.90% | 46.07% | 2.83% | 7.04% |
| 1944 | 19.75% | 18.03% | 4.73% | 3.29% |
| 1945 | 36.44% | 53.33% | 4.08% | 5.92% |
| 1946 | -8.07% | 1.26% | 1.72% | 2.98% |
| 1947 | 5.71% | -13.16% | -2.34% | -2.19% |
| 1948 | 5.50% | 4.01% | 4.14% | 2.65% |
| 1949 | 18.79% | 31.39% | 3.31% | 7.16% |
| 1950 | 31.71% | 3.25% | 2.12% | 2.01% |
| 1951 | 24.02% | 18.63% | -2.69% | -2.77% |
| 1952 | 18.37% | 19.25% | 3.52% | 2.99% |
| 1953 | -0.99% | 7.85% | 3.41% | 2.08% |
| 1954 | 52.62% | 24.72% | 5.39% | 7.57% |
| 1955 | 31.56% | 11.26% | 0.48% | 0.12% |
| 1956 | 6.56% | 5.06% | -6.81% | -6.25% |
| 1957 | -10.78% | 6.36% | 8.71% | 3.58% |
| 1958 | 43.36% | 40.70% | -2.22% | 0.18% |
| 1959 | 11.96% | 7.49% | -0.97% | -2.29% |
| 1960 | 0.47% | 20.26% | 9.07% | 9.01% |
| 1961 | 26.89% | 29.33% | 4.82% | 4.65% |
| 1962 | -8.73% | -2.44% | 7.95% | 6.55% |
| 1963 | 22.80% | 12.36% | 2.19% | 3.44% |
| 1964 | 16.48% | 15.91% | 4.77% | 4.94% |
| 1965 | 12.45% | 4.67% | -0.46% | 0.50% |
| 1966 | -10.06% | -4.48% | 0.20% | -3.45% |
| 1967 | 23.98% | -0.63% | -4.95% | -3.63% |
| 1968 | 11.06% | 10.32% | 2.57% | 1.87% |
| 1969 | -8.50% | -15.42% | -8.09% | -6.66% |
| 1970 | 4.01% | 16.56% | 18.37% | 15.90% |
| 1971 | 14.31% | 2.41% | 11.01% | 11.59% |
| 1972 | 18.98% | 8.15% | 7.26% | 7.19% |
| 1973 | -14.66% | -18.07% | 1.14% | 2.42% |
| 1974 | -26.47% | -21.55% | -3.06% | -5.28% |
| 1975 | 37.20% | 44.49% | 14.64% | 15.50% |
| 1976 | 23.84% | 31.81% | 18.65% | 19.04% |
| 1977 | -7.18% | 8.64% | 1.71% | 5.22% |
| 1978 | 6.56% | -3.71% | -0.07% | -0.98% |
| 1979 | 18.44% | 13.58% | -4.18% | -2.75% |
| 1980 | 32.42% | 15.08% | -2.76% | -0.23% |
| 1981 | -4.91% | 11.74% | -1.24% | 4.27% |
| 1982 | 21.41% | 26.52% | 42.56% | 33.52% |
| 1983 | 22.51% | 20.01% | 6.26% | 10.33% |
| 1984 | 6.27% | 26.04% | 16.86% | 14.82% |
| 1985 | 32.16% | 33.05% | 30.09% | 26.48% |
| 1986 | 18.47% | 28.53% | 19.85% | 18.16% |
| 1987 | 5.23% | -2.92% | -0.27% | 3.02% |
| 1988 | 16.81% | 18.27% | 10.70% | 10.19% |
| 1989 | 31.49% | 47.80% | 16.23% | 15.61% |
| 1990 | -3.17% | -2.57% | 6.78% | 8.13% |
| 1991 | 30.55% | 14.61% | 19.89% | 19.25% |
| 1992 | 7.67% | 8.10% | 9.39% | 8.65% |
| 1993 | 9.99% | 14.41% | 13.19% | 10.59% |
| 1994 | 1.31% | -7.94% | -5.76% | -4.72% |
| 1995 | 37.43% | 42.15% | 27.20% | 22.81% |
| 1996 | 23.07% | 3.14% | 1.40% | 3.04% |
| 1997 | 33.36% | 24.69% | 12.95% | 11.39% |
| 1998 | 28.58% | 14.82% | 10.76% | 9.44% |
| 1999 | 21.04% | -8.85% | -7.45% | -1.69% |
| 2000 | -9.11% | 59.70% | 12.87% | 9.45% |
| 2001 | -11.88% | -30.41% | 10.65% | 5.85% |
| 2002 | -22.10% | -30.04% | 16.33% | 1.63% |
| 2003 | 28.70% | 26.11% | 5.27% | 10.01% |
| 2004 | 10.87% | 24.22% | 8.72% | 6.03% |
| 2005 | 4.91% | 16.79% | 5.87% | 3.02% |
| 2006 | 15.80% | 20.95% | 3.24% | 3.94% |
| | | | | |
| Geometric Mean | 10.10% | 8.80% | 5.85% | 5.45% |
| Arithmetic Mean | 12.03% | 11.14% | 6.17% | 5.73% |
| Standard Deviation | 20.13% | 22.55% | 8.57% | 7.89% |
| Median | 14.31% | 11.74% | 4.14% | 4.45% |

**Tabulation of Risk Rate Differentials for**
**S&P Public Utility Index and Public Utility Bonds**
**For the Years 1928-2006, 1952-2006, 1974-2006, and 1979-2006**

| Total Returns | Range: Geometric Mean | Range: Median | Midpoint | Point Estimate: Arithmetic Mean | Average of the Midpoint of Range and Point Estimate |
|---|---|---|---|---|---|
| **1928-2006** | | | | | |
| S&P Public Utility Index | 8.80% | 11.74% | | 11.14% | |
| Public Utility Bonds | 5.45% | 4.45% | | 5.73% | |
| Risk Differential | 3.35% | 7.29% | 5.32% | 5.41% | 5.37% |
| **1952-2006** | | | | | |
| S&P Public Utility Index | 10.99% | 13.58% | | 12.53% | |
| Public Utility Bonds | 6.17% | 4.94% | | 6.47% | |
| Risk Differential | 4.82% | 8.64% | 6.73% | 6.06% | 6.40% |
| **1974-2006** | | | | | |
| S&P Public Utility Index | 12.79% | 15.08% | | 14.77% | |
| Public Utility Bonds | 8.55% | 8.65% | | 8.90% | |
| Risk Differential | 4.24% | 6.43% | 5.34% | 5.87% | 5.61% |
| **1979-2006** | | | | | |
| S&P Public Utility Index | 13.42% | 15.94% | | 15.27% | |
| Public Utility Bonds | 8.96% | 9.05% | | 9.29% | |
| Risk Differential | 4.46% | 6.89% | 5.68% | 5.98% | 5.83% |

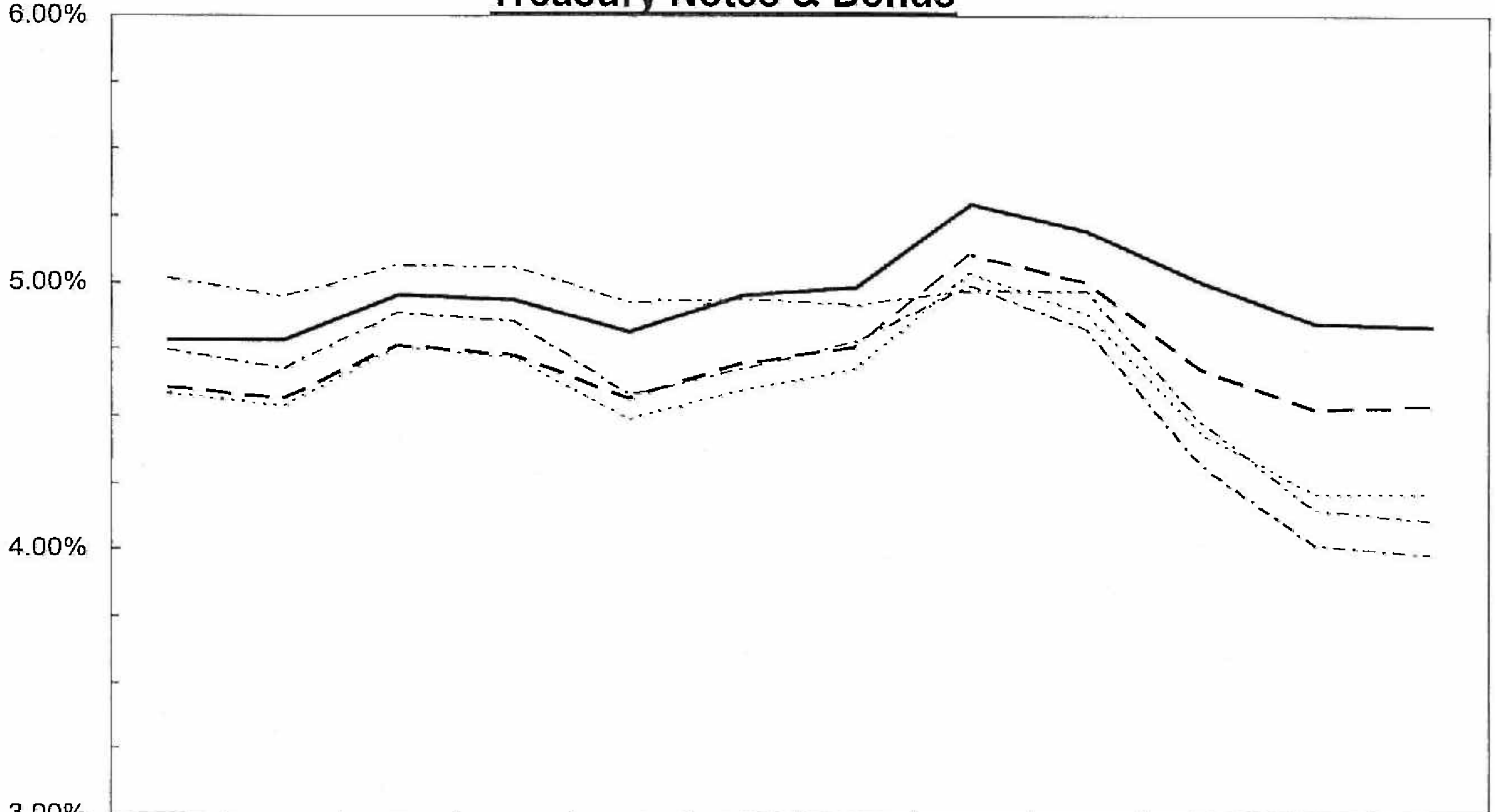
## Value Line Betas

### Gas Group

| | |
|---|---|
| AGL Resources, Inc. | 0.85 |
| Atmos Energy Corp. | 0.85 |
| New Jersey Resources Corp. | 0.85 |
| Northwest Natural Gas | 0.90 |
| Piedmont Natural Gas Co. | 0.85 |
| South Jersey Industries, Inc. | 0.85 |
| WGL Holdings, Inc. | 0.85 |
| Average | 0.86 |

Source of Information:
Value Line Investment Survey
December 14, 2007

# Yields on Treasury Notes & Bonds




| | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Jul-07 | Aug-07 | Sep-07 | Oct-07 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1-Year | 5.01% | 4.94% | 5.06% | 5.05% | 4.92% | 4.93% | 4.91% | 4.96% | 4.96% | 4.47% | 4.14% | 4.10% |
| 2-Year | 4.74% | 4.67% | 4.88% | 4.85% | 4.57% | 4.67% | 4.77% | 4.98% | 4.82% | 4.31% | 4.01% | 3.97% |
| 5-Year | 4.58% | 4.53% | 4.75% | 4.71% | 4.48% | 4.59% | 4.67% | 5.03% | 4.88% | 4.43% | 4.20% | 4.20% |
| 10-Year | 4.60% | 4.56% | 4.76% | 4.72% | 4.56% | 4.69% | 4.75% | 5.10% | 5.00% | 4.67% | 4.52% | 4.53% |
| 20-Year | 4.78% | 4.78% | 4.95% | 4.93% | 4.81% | 4.95% | 4.98% | 5.29% | 5.19% | 5.00% | 4.84% | 4.83% |

**Yields for Treasury Constant Maturities**
**Yearly for 2002-2006**
**and the Twelve Months Ended October 2007**

| Years | 1-Year | 2-Year | 3-Year | 5-Year | 7-Year | 10-Year | 20-Year |
|---|---|---|---|---|---|---|---|
| 2002 | 2.00% | 2.64% | 3.10% | 3.82% | 4.30% | 4.61% | 5.43% |
| 2003 | 1.24% | 1.65% | 2.10% | 2.97% | 3.52% | 4.02% | 4.96% |
| 2004 | 1.89% | 2.38% | 2.78% | 3.43% | 3.87% | 4.27% | 5.04% |
| 2005 | 3.62% | 3.85% | 3.93% | 4.05% | 4.15% | 4.29% | 4.64% |
| 2006 | 4.93% | 4.82% | 4.77% | 4.75% | 4.76% | 4.79% | 4.99% |
| **Five-Year Average** | 2.74% | 3.07% | 3.34% | 3.80% | 4.12% | 4.40% | 5.01% |
| **Months** | | | | | | | |
| Nov-06 | 5.01% | 4.74% | 4.64% | 4.58% | 4.58% | 4.60% | 4.78% |
| Dec-06 | 4.94% | 4.67% | 4.58% | 4.53% | 4.54% | 4.56% | 4.78% |
| Jan-07 | 5.06% | 4.88% | 4.79% | 4.75% | 4.75% | 4.76% | 4.95% |
| Feb-07 | 5.05% | 4.85% | 4.75% | 4.71% | 4.71% | 4.72% | 4.93% |
| Mar-07 | 4.92% | 4.57% | 4.51% | 4.48% | 4.50% | 4.56% | 4.81% |
| Apr-07 | 4.93% | 4.67% | 4.60% | 4.59% | 4.62% | 4.69% | 4.95% |
| May-07 | 4.91% | 4.77% | 4.69% | 4.67% | 4.69% | 4.75% | 4.98% |
| Jun-07 | 4.96% | 4.98% | 5.00% | 5.03% | 5.05% | 5.10% | 5.29% |
| Jul-07 | 4.96% | 4.82% | 4.82% | 4.88% | 4.93% | 5.00% | 5.19% |
| Aug-07 | 4.47% | 4.31% | 4.34% | 4.43% | 4.53% | 4.67% | 5.00% |
| Sep-07 | 4.14% | 4.01% | 4.06% | 4.20% | 4.33% | 4.52% | 4.84% |
| Oct-07 | 4.10% | 3.97% | 4.01% | 4.20% | 4.33% | 4.53% | 4.83% |
| **Twelve-Month Average** | 4.79% | 4.60% | 4.57% | 4.59% | 4.63% | 4.71% | 4.94% |
| **Six-Month Average** | 4.59% | 4.48% | 4.49% | 4.57% | 4.64% | 4.76% | 5.02% |
| **Three-Month Average** | 4.24% | 4.10% | 4.14% | 4.28% | 4.40% | 4.57% | 4.89% |

Source: Federal Reserve statistical release H.15

## Measures of the Risk-Free Rate

The forecast of Treasury yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated January 1, 2008

| Year | Quarter | 1-Year Treasury Bill | 2-Year Treasury Note | 5-Year Treasury Note | 10-Year Treasury Note | 30-Year Treasury Bond |
|---|---|---|---|---|---|---|
| 2008 | First | 3.4% | 3.3% | 3.6% | 4.1% | 4.5% |
| 2008 | Second | 3.4% | 3.4% | 3.7% | 4.1% | 4.5% |
| 2008 | Third | 3.5% | 3.5% | 3.8% | 4.2% | 4.6% |
| 2008 | Fourth | 3.6% | 3.6% | 4.0% | 4.4% | 4.7% |
| 2009 | First | 3.8% | 3.8% | 4.1% | 4.4% | 4.8% |
| 2009 | Second | 3.9% | 4.0% | 4.2% | 4.6% | 4.9% |

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

# THE VALUE LINE Investment Survey®

Part 1 Summary & Index

January 4, 2008

## TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number



### SCREENS



The Median of Estimated **PRICE-EARNINGS RATIOS** of all stocks with earnings

**17.6**

| 26 Weeks Ago | Market Low 10-9-02 | Market High 5-5-06 |
|---|---|---|
| 19.0 | 14.1 | 19.6 |

The Median of Estimated **DIVIDEND YIELDS** (next 12 months) of all dividend paying stocks under review

**1.9%**

| 26 Weeks Ago | Market Low 10-9-02 | Market High 5-5-06 |
|---|---|---|
| 1.6% | 2.4% | 1.6% |

The Estimated Median Price **APPRECIATION POTENTIAL** of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

**50%**

| 26 Weeks Ago | Market Low 10-9-02 | Market High 5-5-06 |
|---|---|---|
| 40% | 115% | 40% |

## ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).



*Reviewed in this week's issue.

**In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LXIII, No. 19.**
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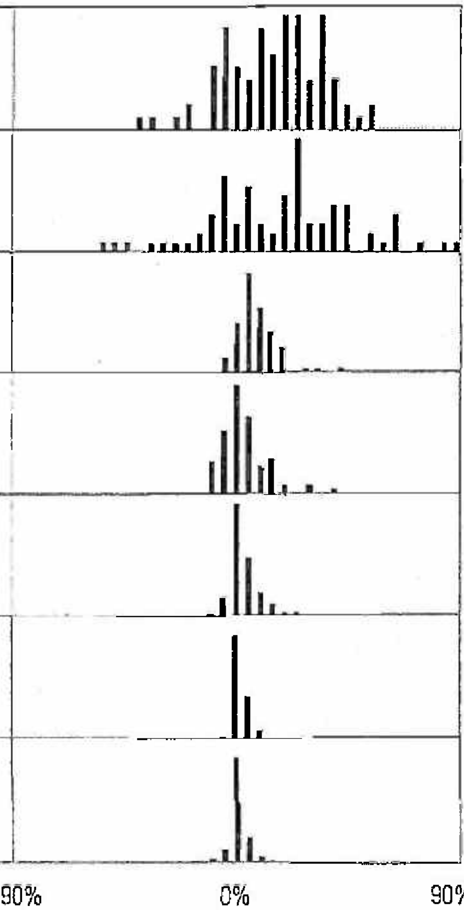
**See back cover for important disclosures.**

Table 2-1
**Basic Series: Summary Statistics of Annual Total Returns**

Attachment PRM-20
National Grid NH
DG 08-009
Page 6 of 6

from 1926 to 2006

| Series | Geometric Mean | Arithmetic Mean | Standard Deviation | Distribution |
|---|---|---|---|---|
| Large Company Stocks | 10.4% | 12.3% | 20.1% | |
| Small Company Stocks | 12.7 | 17.4 | 32.7 | * |
| Long-Term Corporate Bonds | 5.9 | 6.2 | 8.5 | |
| Long-Term Government | 5.4 | 5.8 | 9.2 | |
| Intermediate-Term Government | 5.3 | 5.4 | 5.7 | |
| U.S. Treasury Bills | 3.7 | 3.8 | 3.1 | |
| Inflation | 3.0 | 3.1 | 4.3 | |




*The 1933 Small Company Stocks Total Return was 142.9 percent.

**Comparable Earnings Approach**
Using Non-Utility Companies with
Timeliness of 3 & 4; Safety Rank of 1 & 2; Financial Strength of B+, B++ & A;
Price Stability of 90 to 100; Betas of .85 to .90; and Technical Rank of 3 & 4

| Company | Industry | Timeliness Rank | Safety Rank | Financial Strength | Price Stability | Beta | Technical Rank |
|---|---|---|---|---|---|---|---|
| Avery Dennison | CHEMSPEC | 4 | 2 | A | 90 | 0.90 | 3 |
| Bank of Hawaii | BANK | 3 | 2 | B++ | 100 | 0.85 | 3 |
| Campbell Soup | FOODPROC | 3 | 2 | B++ | 100 | 0.85 | 3 |
| Cincinnati Financial | INSPRPTY | 3 | 2 | B++ | 100 | 0.85 | 3 |
| City National Corp. | BANK | 4 | 2 | B++ | 95 | 0.85 | 3 |
| Commerce Bancshs. | BANKMID | 3 | 1 | A | 100 | 0.85 | 3 |
| Int'l Flavors & Frag. | CHEMSPEC | 3 | 2 | B++ | 95 | 0.85 | 3 |
| Mercury General | INSPRPTY | 3 | 2 | B++ | 95 | 0.85 | 3 |
| Northrop Grumman | DEFENSE | 3 | 1 | A | 95 | 0.85 | 3 |
| Old Nat'l Bancorp | BANKMID | 3 | 2 | B++ | 90 | 0.90 | 3 |
| Pitney Bowes | OFFICE | 3 | 1 | A | 100 | 0.85 | 3 |
| PNC Financial Serv. | BANK | 3 | 2 | B++ | 95 | 0.90 | 3 |
| Regions Financial | BANK | 4 | 1 | A | 95 | 0.90 | 3 |
| Reinsurance Group | INSLIFE | 3 | 1 | A | 95 | 0.85 | 4 |
| Scripps (E.W.) 'A' | NWSPAPER | 3 | 2 | B+ | 95 | 0.85 | 3 |
| Weis Markets | GROCERY | 3 | 1 | A | 90 | 0.85 | 3 |
| Whitney Holding | BANK | 4 | 2 | B+ | 90 | 0.90 | 3 |
| Average | | 3 | 2 | B++ | 95 | 0.86 | 3 |
| Gas Group | Average | 4 | 2 | B++ | 100 | 0.86 | 3 |

Source of Information: Value Line Investment Survey for Windows, December 2007

**Comparable Earnings Approach**
Five -Year Average Historical Earned Returns
for Years 2002-2006 and
Projected 3-5 Year Returns

| Company | 2002 | 2003 | 2004 | 2005 | 2006 | Average | Projected 2009-12 |
|---|---|---|---|---|---|---|---|
| Avery Dennison | 26.5% | 20.1% | 19.8% | 22.3% | 22.6% | 22.3% | 20.5% |
| Bank of Hawaii | 11.9% | 17.0% | 21.3% | 26.2% | 26.3% | 20.5% | 19.5% |
| Campbell Soup | - | 161.8% | 74.7% | 55.7% | 38.5% | 82.7% | 31.0% |
| Cincinnati Financial | 5.4% | 6.2% | 8.4% | 9.2% | 7.3% | 7.3% | 7.5% |
| City National Corp. | 16.3% | 15.3% | 15.3% | 16.1% | 15.7% | 15.7% | 15.0% |
| Commerce Bancshs. | 14.1% | 14.2% | 15.4% | 16.7% | 15.2% | 15.1% | 13.0% |
| Int'l Flavors & Frag. | 32.0% | 26.9% | 21.5% | 20.1% | 23.6% | 24.8% | 26.5% |
| Mercury General | 10.2% | 14.1% | 18.4% | 15.1% | 11.8% | 13.9% | 13.5% |
| Northrop Grumman | 4.8% | 4.8% | 6.4% | 7.4% | 9.2% | 6.5% | 12.0% |
| Old Nat'l Bancorp | 14.8% | 9.8% | 9.6% | 12.1% | 12.4% | 11.7% | 13.5% |
| Pitney Bowes | 67.0% | 52.3% | 46.0% | 48.1% | 87.0% | 60.1% | 44.0% |
| PNC Financial Serv. | 17.5% | 15.5% | 16.0% | 15.5% | 14.0% | 15.7% | 14.0% |
| Regions Financial | 14.8% | 14.6% | 8.1% | 9.4% | 6.5% | 10.7% | 10.5% |
| Reinsurance Group | 10.5% | 8.5% | 9.9% | 8.9% | 10.4% | 9.6% | 11.5% |
| Scripps (E.W.) 'A' | 15.2% | 13.6% | 13.8% | 13.6% | 15.4% | 14.3% | 12.5% |
| Weis Markets | 10.4% | 9.5% | 10.0% | 10.5% | 8.9% | 9.9% | 10.0% |
| Whitney Holding | 11.9% | 11.7% | 10.7% | 10.6% | 13.0% | 11.6% | 10.0% |
| Average | | | | | | 20.7% | 16.7% |
| Median | | | | | | 14.3% | 13.5% |

# STATE OF NEW HAMPSHIRE
# BEFORE THE
# PUBLIC UTILITIES COMMISSION

ORIGINAL
N.H.P.U.C. Case No. DG 08-009
Exhibit No. #13

**EnergyNorth Natural Gas, Inc.**
**d/b/a National Grid NH**

**Docket DG 08-009**

**Direct Testimony**
**of**
**Susan L. Fleck**

**February 25, 2008**

## I. Introduction and Qualifications

**Q. Please state your full name, business address and title.**

A. My name is Susan Fleck. My business address is 52 Second Avenue, Waltham, MA 02451. I am Vice President of Engineering Standards and Policy for National Grid USA.

**Q. Please describe your educational background and professional experience.**

A. I received a B.S. in Civil Engineering from Carnegie-Mellon University in 1980. In 1989, I received an M.B.A. with a finance concentration from Boston College. From 1980 to 1981, I worked as an engineer for Columbia Gas Transmission Company in the Measurement and Regulation Department. In 1981, I joined The Brooklyn Union Gas Company as an Engineer, where I remained until 1982. From 1982 to 1985, I was employed by Consolidated Edison Company as an Associate Engineer in the Gas Operations Department. In 1985, I joined Boston Gas Company as a Measurement and Design Engineer. I remained with Boston Gas through the end of 2000, progressing through numerous positions including: Superintendent Distribution Administration, Director Distribution System Planning, Group Leader Distribution System Design, Construction Engineer, Vice President Engineering and Gas Control, and Vice-President Engineering and Environmental Management. Following the acquisition of Boston Gas Company by KeySpan Corporation, I relocated to New York and was named Vice-President NYC Gas Operations for KeySpan Energy Delivery New York. Following the acquisition of KeySpan Corporation by National Grid plc in August of 2007, I returned to New England and was named to my current position.

**Q. Are you a member of any professional organizations?**

A. Yes. I am a member of the American Gas Association and current Chair of the Operations Managing Committee. I am also a member of the American Society of Civil Engineers.

**Q. Have you ever testified before a regulatory agency?**

A. Yes. When I was with Boston Gas Company, I testified before the Massachusetts Department of Public Utilities in support of a proposal to uprate the intermediate pressure distribution system.

**Q. Would you briefly describe your current areas of responsibility for National Grid?**

A. In my position as Vice-President of Engineering Standards and Policy, I have several areas of responsibility. First, I am responsible for ensuring Gas Operations' compliance with all state and federal codes and standards related to gas pipeline safety. This includes responsibility for reporting and communications with regulatory agencies. Second, I am responsible for review, development and communications of all internal company policies, codes and standards related to gas pipeline safety. Third, I am responsible for material specifications and review of material failures. Finally, I am responsible for coordination of the company's research and development activities that relate to gas pipeline safety.

## II. <u>Purpose of Testimony</u>

**Q. What is the purpose of your testimony?**

A. My testimony: (i) describes the gas operations of EnergyNorth Natural Gas, Inc. d/b/a National Grid NH ("National Grid NH" or the "Company") and its proposed system investment plans; (ii) discusses capital improvements to the National Grid NH system since its acquisition by KeySpan Corporation and (iii) explains how National Grid NH will address the service quality commitments that are incorporated in the merger settlement agreement approved by the Commission in Order No. 24,777 dated July 12, 2007.

## III. National Grid NH Operations and System Investment Plans

**Q. Would you please provide an overview of National Grid NH's operations?**

A. National Grid NH distributes natural gas to approximately 84,000 residential, commercial, and industrial customers in 30 cities and towns in southern and central New Hampshire as well as to the City of Berlin in northern New Hampshire.

**Q. When were National Grid NH's delivery rates last reviewed by the Commission?**

A. I understand from the Company's regulatory personnel that the Company's revenue requirement was last set in an order issued in 1993 in Docket DR 91-212. Thus, it has been fifteen years since the Company's last general rate case. During that time, the Company has been able to maintain rate stability through sales growth, merger synergies and cost reductions, and efficiency programs. However, inflation, investment in non-growth related capital projects designed to improve the safety and reliability of the Company's distribution system and other increases in the costs of providing service to customers have caught up with the Company and affected its financial performance, necessitating its request for a rate increase. Since the Company's acquisition by KeySpan Corporation in 2001, the Company has invested $62 million in non-growth capital projects. In addition, National Grid NH plans to invest an additional $40 million in non-growth related capital projects over the next 2 years.

**Q. Would you please describe the major capital projects undertaken by the Company since its acquisition by KeySpan Corporation that are included in rate base in this case?**

A. Significant distribution system investment projects undertaken since 2001 include the construction of the distribution line that provides service to the AES Granite Ridge Generating facility in Londonderry (formerly known as AES Londonderry) and upgrades to the Company's Tilton line.

The AES Granite Ridge project involved the construction of a 2.8 mile natural gas pipeline from a take station on the Concord Lateral of the Tennessee Gas Pipeline Company system to the AES 720 megawatt gas-fired electric generating station in Londonderry. Service to the AES facility is provided in accordance with a negotiated gas transportation agreement. As part of the transaction, AES also agreed to provide National Grid NH with access to firm transportation capacity held by AES on the Tennessee Gas Pipeline system during the peak winter period under a Natural Gas Firm Peaking Agreement. Pursuant to a settlement between the Company, the PUC Staff and the Office of the Consumer Advocate, the Commission approved the Company's construction plans and specifications, the

Gas Transportation Agreement and the Natural Gas Peaking Agreement in Order No. 23,657 dated March 22, 2001. On November 18, 2002, in accordance with the requirements of the Commission order, the Company submitted a report of the capitalized costs of the project, which amounted to $7,100,697. The main extension has since been placed in service and is used and useful in providing service.

The Tilton line is a 22 mile distribution main that originates at the Concord Take Station and extends to the Tilton LNG Plant. The line traverses the City of Concord and the Towns of Pembroke, Loudon, Canterbury, Northfield and Tilton. Approximately 4,700 customers in 10 municipalities are served from the Tilton line. In 2002, the Company undertook a project to upgrade the Tilton line. At the time, the Tilton line consisted entirely of 6-inch thin wall (0.141–inch wall thickness) pipe with a maximum allowable operating pressure ("MAOP") of 200 psig. In addition, there were 232 farm tap regulators located along the main. The plan provided for the Company to parallel the 22 miles of existing pipe with 12-inch pipe, down-rate the existing 6-inch pipe and remove the farm taps. The goal of the project was to support the Company's forecasted growth expectations and to improve system reliability through the installation of more durable pipe and by reducing reliance on LNG and liquid propane facilities and trucking. Between 2003 and 2006, the Company completed the first phase of the project. This included:

- In 2003, the Company installed 4.5 miles of 12-inch pipe (originating at the Concord Take Station).

- In 2004, the Company installed an additional 1.8 miles of 12-inch pipe and down-rated approximately 6.5 miles of 6-inch pipe. The Company also made modifications to the Concord Take Station facility.
- In 2005, the Company replaced 183 buried farm tap regulators with prefabricated units in vaults, completed engineering design work for the remainder of the pipeline and made modifications to the take station at Tilton.

  The total cost of the Phase I work was $9.7 million, a significant portion of which was offset by a contribution from Tennessee Gas Pipeline.

At the conclusion of Phase I, the Company determined that actual growth in the areas served by the Tilton line was slower than had been forecasted in 2002. Thus, the Company suspended work until additional customer growth or other considerations warranted further upgrades. The Company currently expects to resume work in the 2009/2010 timeframe.

**Q. Were these the only two significant capital improvement projects since 2001?**

A. No. Attachment SLF-1 lists a number of other major distribution system projects undertaken by the Company during that time frame.

**Q. Are all of these projects used and useful in providing service to the Company's customers?**

A. Yes. All of these projects are operational and providing service to the Company's customers.

**Q. What are the Company's future system investment plans?**

A. As noted above, National Grid NH plans to invest an additional $40 million in non-growth related capital projects over the next 2 years. This is comprised of

$20.8 million of mandated work due to public works projects, main encroachments and other similar situations, $17.9 million of reliability and system integrity projects and $1.2 million of capital equipment purchases. Although the Company's distribution system has been well maintained on a historic basis, a portion of the system still consists of cast iron and bare steel mains and services, which are subject to higher corrosion and leak levels. For that reason, one of the key elements of the EnergyNorth Merger Rate Agreement approved by the Commission in Order 24, 777, dated July 12, 2007, was the inclusion of a Cast Iron/Bare Steel Replacement Program ("CIBS"). Under that provision of the settlement, the Company agreed to work with Staff each year to establish appropriate target levels for reliability related capital spending. As required by the terms of the agreement approved by the Commission, the Company expects to meet with Staff to engage in technical sessions and reach agreement on the final pipe segments to be replaced by the Company. The Company's initial incremental replacement proposal for fiscal year 2009 (12 months ending March 2009) includes plans to replace approximately 4.76 miles of pipe at a cost of approximately $3.1 million. This level of spending is over and above any required spending that results for public works projects that impact the Company's infrastructure. Moreover, the process put in place as a result of the merger settlement is consistent with the Company's efforts to move towards a risk-based methodology of assessing the performance of its distribution system assets.

**Q. Please explain what you mean by a risk-based methodology of assessing the**

**performance of the Company's distribution system assets.**

A. The delivery infrastructure used to provide service to customer homes and businesses encompasses a broad range of system components of varying material, vintage and operation and maintenance histories. The objective of a risk-based methodology is to identify by category the mains and services most likely to be leak prone and to establish a preventive program to replace those assets.

The Company will achieve this objective through its efforts to comply with applicable state and federal pipeline safety requirements, as well as through the development and application of internal O&M standards that are designed to set optimal thresholds for asset integrity and system maintenance across all operating areas within the National Grid service territory.

**Q. Is this approach consistent with the Federal Distribution Integrity Management program that is under discussion at the Pipeline Hazardous Materials Safety Administration ("PHMSA")?**

A. Yes. As the Chairperson of the American Gas Association Operations Management Committee, I am aware that PHMSA is planning on issuing draft regulations in April 2008, which would impose new requirements on LDC pipeline operators. These regulations are designed to move away from a "command and control" framework establishing O&M codes and standards. Under the new regulatory plan, pipeline operators like National Grid NH would be required to establish O&M work plans based on an assessment of system maintenance requirements and asset integrity. This new system would require the pipeline operator to conduct risk assessments of system maintenance requirements and asset integrity considerations and to bear responsibility for maintaining its system within acceptable risk tolerances.

**Q. Are there any significant factors that may affect the Company's future CIBS spending levels?**

A. As noted above, the Company has proposed a $3.1 million budget for the CIBS program for fiscal year 2009. We expect to continue CIBS spending at similar levels in future fiscal years. However, a key feature of the program agreed upon in the Merger Rate Agreement allows for the possibility of changed circumstances going forward. Significantly, each year the Company will review its system and prioritize the cast iron and bare steel main segments that are candidates for replacement and set an appropriate budget level based on leak history as well as its mandated capital investment requirements for the remainder of the system. The Commission staff will have an opportunity to review the Company's proposal and determine if the spending level is appropriate under the particular circumstances of that fiscal year, taking into account the bill impact to customers. Thus, to the extent there are circumstances that affect the need for and the ability of the Company to ramp up or ramp down the program in any particular year those circumstances can be fully explored prior to implementation.

## IV. Service Quality

**Q. The merger settlement provides that the Company will comply with certain emergency response time standards beginning in January 2008. Has the Company made any changes to its operations as a result of that agreement?**

A. Yes. The emergency response time standards to which the Company agreed are set forth at Exhibit EN-4 of the merger settlement and reproduced below:

| **Emergency Response Performance Measures** | | |
|---|---|---|
| **Performance Measures** | **Response Time** | **Percent to Achieve** |
| | | |
| **Normal Business Hours** | 30 Minutes<br>45 minutes<br>60 minutes | 82%<br>90%<br>97% |
| | | |
| **After Hours** | 30 Minutes<br>45 minutes<br>60 minutes | 80%<br>86%<br>95% |
| | | |
| **Weekends/Holidays** | 30 Minutes<br>45 minutes<br>60 minutes | 76%<br>84%<br>94% |

To meet these emergency response performance targets, the Company developed and implemented a capacity enhancement strategy that has allowed it to reduce emergency response time after hours and on weekends, the times when historical performance was below the agreed upon targets. Key considerations in the development of the strategy of where and when to stage staff included the vast geography of the Company's service territory and the extremely small number of leak calls received. The key components of our capacity enhancement strategy include:

1. Add six (6) incremental FTE's and optimize shifts to extend staffing during time periods when calls are most likely to come in.
2. Add a dedicated Service Supervisor.
3. Enhance focus in Dispatch to closely monitor and manage dispatch wait times, travel times and drive effective assignment decisions.

4. Introduce Standby Initiatives to improve off-hours response times through:
    a. Strategic placement of standby resources
    b. Increased standby options
    c. Standby Incentive Pilot.

The annual cost of these changes is $1.2 million. In accordance with section 7 N (3) of the EnergyNorth Merger Rate Agreement, the Company has included these incremental costs for recovery in this filing. They are shown on Exhibit EN 2-2-2.

**Q. The merger settlement also provides that by the end of 2008, the Company will answer 80% of calls within 30 seconds. Has the Company made any changes to its operations to comply with this provision?**

A. Although the call center is not within my area of responsibility and control, I have obtained information regarding this area from the appropriate Company personnel. The Company has made the following changes to its operations in order to comply with this provision:

- Additional customer service representatives ("CSR") were trained on National Grid NH procedures to expand the number of CSRs available to handle National Grid NH calls.
- Call queuing priorities were adjusted to consider the higher service level commitment for National Grid NH calls.
- CSR shifts were evaluated and subsequently adjusted to better align with National Grid NH call patterns – i.e., more CSRs available to handle calls when they

arrive. The Company will continue to monitor its performance levels and make further adjustments as needed.

**Q. Does that conclude your testimony?**

A. Yes. It does.

# MAJOR NH PROJECTS SINCE 2001

| YEAR | TOWN | LOCATION | SCOPE | LOADED COST | WORK ORDERS |
|---|---|---|---|---|---|
| 2003/2007 | Hudson/Nashua/ Merrimack | Highland St, Webster St, Bridge St, Railroad ROW, Hills Ferry Rd, Concord Rd, & DWH from the Hudson Take Station to the DWH@Sanderson, Merrimack 60 psig district regulator | System Reinforcement/Reliability: Uprated 6 miles of 12" CS main from 60 psig to 130 psig and then to 185 psig to maintain adequate inlet pressure to the DWH@Sanderson 60 psig district regulator in Merrimack and to eliminate reliance on the Nashua Propane facility. Uprating required the installation of two 60 psig district regulators. | $2,239,486 | 546524, 546517, 274013, 227798, 278569, 270430 |
| 2007 | Nashua/Merrimack | Amherst St (Rte 101A) from Thornton Rd to Boston Post Rd | System Reinforcement: Installed 10,400' of 12" (60 psig) CS main to maintain adequate pressures in the Amherst/Milford area | $2,544,119 | 512879, 512636 |
| 2006/07 | Concord | North State St & Sewalls Falls Rd from Rumford St to Second St | System Reinforcement/ Reliability: Installed 14,250' of 8" (60 psig) PL main to maintain adequate pressures in Penacook and provide a second supply to the area | $2,199,613 | 481647, 498592, 490372, 532024, 469659 |
| 2006/07 | Belmont | Daniel Webster Highway (Rte 3) from #225 to Court St | System Reinforcement/Public Works: Replaced 6,450' of 8" (60 psig) CS main, in conflict w/ a DOT project, with 12" CS to maintain adequate pressures to the Laconia/Gilford area | $1,649,467 | 477096, 476990, 477005 |
| 2005 | Concord | Loudon Rd, Concord from Hazen Dr to the Merrimack River | System Reinforcement: Installed 3,500' of 8" (60 psig) PL main to maintain adequate pressure to the west side of Concord | $557,998 | 415690 |
| 2002/03 | Merrimack | Daniel Webster Highway (Rte 3) from #318 to #696 and from #140 to Pennichuk Rd | Managed Expansion Project: Installed 6 miles of 6" (60 psig) PL main to provide service numerous businesses along Daniel Webster Hwy | $1,600,339 | 251682 |
| 2002/03 | Tilton | Laconia Rd, Tilton (Rte 3) from #232 to #416 | System Reinforcement: Installed 4,400' of 12" (60 psig) CS main to maintain adequate pressures to the Laconia/Gilford area | $515,020 | 275318, 277326 |

## MAJOR NH PROJECTS SINCE 2001

| | | | | | |
|---|---|---|---|---|---|
| 2002/03 | Hooksett/Bow | W River Rd, Riverside Rd, N Main St, Rte 3A, Dunklee Rd, and River Rd from #311 W River Rd to #585 Rte 3A | Managed Expansion Project: Installed 5 miles of 6" (60 psig) PL main to serve the Bow Industrial Park | $1,084,230 | 305516, 277005 |
| 2002 | Amherst | Old Nashua Rd from Milford Rd to Captain Danforth Ln | System Reinforcement: Installed 4,000' of 12" (60 psig) CS main to maintain adequate pressures in the Amherst/Milford area | $400,906 | 227427 |
| 2002 | Londonderry | Mammoth Rd from Smith Lane to Orchard View Dr | Managed Expansion Project: Installed 15,000' of 8" (60 psig) PL and extensive 2" PL local main to serve town office buildings, school, etc. | $2,208,251 | 233757 |