



**NATIONAL FUEL GAS  
DISTRIBUTION CORPORATION  
PENNSYLVANIA PUBLIC UTILITY COMMISSION  
DOCKET NO. R-00061493**

**Information Submitted Pursuant to Pa. PUC Regulation  
Regarding Filing of Rate Changes**

**Tariff Gas Pa. P.U.C. No. 9  
Volume V**

National Fuel Gas Distribution Corporation  
Direct Testimony of Kathleen A. Frank

1 Q. Please state your name and business address.

2 A. My name is Kathleen A. Frank. My business address is 6363 Main  
3 Street, Williamsville, New York 14221.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by National Fuel Gas Distribution Corporation  
6 ("Distribution") as an Assistant General Manager in the Credit, Collections  
7 and Receivables Management Department.

8 Q. Briefly describe your educational background and your business  
9 experience.

10 A. In June of 1978, I received a Bachelor of Science degree in Accounting  
11 from the State University of New York at Buffalo. In June of 1984, I  
12 received a Masters of Business Administration from the State University  
13 of New York at Buffalo. I began my career with Distribution as a Budget  
14 Analyst. I have held various managerial positions in the Finance and  
15 Accounting departments and am currently employed as an Assistant  
16 General Manager in the Credit, Collections and Receivables  
17 Management Department.

18 Q. Have you previously testified before this Commission?

19 A. Yes. I testified before this Commission on behalf of Distribution in Docket  
20 No. R-000038168 and Docket No. R-00049656.

21 Q. What is the purpose of your testimony in this proceeding?

22 A. I am sponsoring Exhibit No. 4 Schedule 2 (Uncollectibles) Page 5, which  
23 describes the calculation of the normalized uncollectible accounts

National Fuel Gas Distribution Corporation  
Direct Testimony of Kathleen A. Frank

1 expense for the twelve months ended January 31, 2006. I am also  
2 sponsoring Exhibit No. 16.

3 Q. How is the normalized uncollectible expense of \$8,782,652 for the 12  
4 months ended January 31, 2006 as shown in Exhibit No. 4 Schedule 2  
5 (Uncollectibles) Page 5 calculated?

6 A. The \$8,782,652 is based upon the write-off factor calculation of  
7 uncollectible accounts expense as presented in Exhibit No. 104 Schedule  
8 2 (Uncollectibles), page 7 and the sales and transportation revenues as  
9 presented in Exhibit No. 3. The development of Exhibit No. 104 Schedule  
10 2 (Uncollectibles) is described in Statement No. 101.

11 Q. Were there any adjustments to the uncollectible accounts expense during  
12 the twelve months ended January 31, 2006?

13 A. Typically the accrual amount for uncollectible accounts expense is  
14 established on a fiscal year basis. During the course of a fiscal year, the  
15 uncollectible accounts expense is reviewed on a quarterly and annual  
16 basis. During the twelve months ended January 31, 2006, due to an  
17 inadequacy in the reserve for uncollectible accounts, approximately  
18 \$7,000,000 of additional uncollectible expense was booked.

19 Q. Do you sponsor any other exhibits related to the 12 months ending  
20 January of 2006?

21 A. Yes, I also sponsor Exhibit No. 16.

22 Q. Please describe Exhibit No. 16.

National Fuel Gas Distribution Corporation  
Direct Testimony of Kathleen A. Frank

1 A. Exhibit No. 16, Schedule No. 1, pages 1 through 4, provides the details of  
2 Distribution Pennsylvania Division's attempts to recover uncollectible  
3 delinquent accounts.

4 Q. Does this conclude your testimony regarding the 12 months ended  
5 January 31, 2006?

6 A. Yes, at this time.

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 Q. Please state your name and business address.

2 A. My name is Ruth M. Friedrich-Alf. My business address is 6363 Main  
3 Street, Williamsville, New York 14221-5887.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by National Fuel Gas Distribution Corporation ("Distribution")  
6 as a Senior Rate Analyst in the Rates and Regulatory Affairs Department.

7 Q. Please describe your educational background.

8 A. In 1982, I graduated from the State University of New York at Buffalo with a  
9 Bachelor of Science degree in Industrial Engineering. In May of 1987, I  
10 received a Master's degree in Business Administration from Canisius  
11 College in Buffalo.

12 Q. Please describe your experience at Distribution.

13 A. In January 1985, I began my career at Distribution in the Industrial  
14 Engineering Department as an Analyst. In April 1991, I transferred to  
15 Distribution's Valuation Department now Rates and Regulatory Affairs.

16 Q. Have you previously testified before the Pennsylvania Public Utility  
17 Commission before?

18 A. Yes. I testified before this Commission on behalf of Distribution in Docket  
19 Nos. R-942991, R-953299, R-984497, R-994898, R-00005832, R-  
20 00016789, R-00038168 and R-00049656.

21 Q. Have you testified before any other Commission?

22 A. Yes, I have testified before the New York State Public Service Commission  
23 in a number of proceedings.

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 Q. What is the subject of your testimony in this proceeding?

2 A. My testimony will relate to the overall requested increase in revenue,  
3 adjustments to cost of service items and rate base for the twelve months  
4 ended January 31, 2006, as well as various miscellaneous exhibits that  
5 address the Commission's regulations.

6 Q. Which exhibits were prepared by you or under your direction?

7 A. I am responsible for the information submitted in the following Exhibits  
8 relating to the historic test year, the twelve months ended January 31, 2006:

9 Exhibit No. 2 Schedules 1 - 3

10 Exhibit No. 4 Schedules 1 – 10

11 Exhibit No. 6 Schedule 1

12 Exhibit No. 8 Schedules 1 – 3 and Schedule 5

13 Exhibit No. 13

14 Q. Please refer to Exhibit No. 2 Schedules 1 - 3. What is shown in this Exhibit?

15 A. Exhibit No. 2 Schedules 1 and 2 are the Company responses to several  
16 regulations including

17 Regulation 53.52 (b) 2 requests "The operating income statement of  
18 the utility for a 12-month period, the end of which may not be more than 120  
19 days prior to the filing."

20 Exhibit 2 Schedule 3 is a Statement of Income at Present and  
21 Proposed Rates for the Pennsylvania Division for the twelve months ended  
22 January 31, 2006. Also provided on this Exhibit is the rate of return at  
23 present rates, proforma at present rates and proforma at proposed rates at

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 the level of operations at January 31, 2006. Column 1 of this exhibit reflects  
2 the operating revenues, operating revenue deductions, income taxes, and  
3 utility operating income for the Pennsylvania Division of Distribution for the  
4 twelve months ended January 31, 2006.

5 Column 2 presents ratemaking adjustments required at present rates.  
6 Column 3 shows the normalized operating revenues, operating revenue  
7 deductions, income taxes and utility operating income for the Pennsylvania  
8 Division of Distribution for the twelve months ended January 31, 2006, at  
9 present rates. The various exhibits in support of these amounts are  
10 identified in Column 6. Column 4 of Exhibit No. 2 Schedule 3 provides the  
11 adjustments necessary to annualize the effects of the proposed increase in  
12 base rates. Column 5 provides the annualized and normalized statement of  
13 income at proposed base rates for the twelve months ended January 31,  
14 2006.

15 Q. Please refer to Exhibit No. 4 Schedules 1 - 10. What is shown in this  
16 Exhibit?

17 A. Exhibit No. 4 Schedules 1 – 10 provides the support of the Operation and  
18 Maintenance Expenses for the twelve months ended January 31, 2006.

19 This exhibit represents the Operation and Maintenance Expenses for the  
20 Pennsylvania Division detailed by elements of cost.

21 Q. Why have you shown expenses by cost elements?

22 A. Each element is a combination of similar Operation and Maintenance  
23 expenses. Historic test year expenses have been shown by cost elements

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 to facilitate comparison between historic and future test year data. This is  
2 the same procedure followed by Distribution in its last several rate case  
3 presentations.

4 Q. Please explain Exhibit No. 4 Schedule 1.

5 A. Exhibit No. 4 Schedule 1 Page 2 represents total Operation and  
6 Maintenance Expense for the historic test year ended January 31, 2006.  
7 Column 1 shows the per book expenses by cost element totaling  
8 \$69,278,700. Column 2, totaling \$X, sets forth ratemaking adjustments  
9 made to the expenses for the historic test year. These adjustments are  
10 detailed in Exhibit No. 4 Schedule 2 as referenced. Adding Column 2 to  
11 Column 1 gives \$X as shown in Column 3, which is the total Operation and  
12 Maintenance Expense, as adjusted at present base rates, for the  
13 Pennsylvania Division for the twelve months ended January 31, 2006.

14 Q. Please refer to Exhibit No. 4 Schedule 2 (Labor) Page 1, and explain the  
15 adjustment to Labor Expense for the twelve months ended January 31,  
16 2006.

17 A. Exhibit No. 4 Schedule 2 (Labor) Page 1 is the summary of the Labor  
18 Expense by category. Labor Expense is composed of Pennsylvania  
19 Division labor, labor borrowed from Distribution's New York Division (New  
20 York), and labor borrowed from National Fuel Gas Supply Corporation  
21 (Supply). The first column shows for the twelve months ended January 31,  
22 2006 the Pennsylvania labor charged to Operation and Maintenance

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 Expense was \$14,029,186, the labor borrowed from New York was  
2 \$3,379,319 and the labor borrowed from Supply was \$1,259,818 for a total  
3 of \$18,668,323. The normalization of these components is found on the  
4 remaining pages in Exhibit 4 Schedule 2 (Labor).

5 Q. Please explain the normalization as found in Exhibit 4 Schedule 2 (PAD  
6 Labor) Page 2.

7 A. Exhibit 4 Schedule 2 (PAD Labor) Page 2 normalizes the salaries and  
8 wages for the employees of the Pennsylvania Division. The normalizations  
9 were calculated using data from a recent pay period for each category of  
10 employee in order to reflect a recent employee complement and payroll.

11 The clerical payroll was annualized by first reducing the payroll for the  
12 week ended January 14, 2006, by the overtime payroll to determine the  
13 base weekly payroll of \$51,746 (Column 1). This payroll included the wage  
14 increase effective January 1, 2006. I multiplied this base weekly payroll by  
15 52.14 weeks to arrive at an annualized clerical payroll of \$2,698,047.

16 Next, I computed the annualized payroll for each bargaining group.  
17 Again, I removed the overtime payroll from each bargaining group payroll for  
18 the week ended January 14, 2006. This resulted in a base weekly payroll of  
19 \$71,238 for Local 22 which was increased for a 2% contractual wage  
20 increase effective April 30, 2006. Local 2154 PA (historically Local 2279)  
21 has a base payroll of \$79,518 which was increase for a 2.5% contractual  
22 wage increase effective April 16, 2006. I multiplied each base weekly payroll  
23 by 52.14 weeks to arrive at an annualized for each bargaining group payroll

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 of \$3,788,646 and \$4,249,698, respectively.

2 Each bargaining group also has supplemental employees that are  
3 calculated separately due to the structure of their potential payroll.

4 Supplemental employees have the capability of earning pay above their  
5 base pay based on exceeding workload goals. Because this structure is  
6 available to the supplemental employees, the payroll that is annualized  
7 includes their additional pay. The Local 2154 PA supplemental payroll was  
8 \$8,820 and Local 22 supplemental was \$3,781 for the week ended January  
9 14, 2006. I multiplied each weekly payroll by 52.14 weeks to arrive at a  
10 normalized level for each bargaining supplemental group payroll of \$471,392  
11 and \$201,077, respectively.

12 The supervisory payroll was annualized by multiplying the total  
13 salaries for the pay period ended January 31, 2006 of \$246,187 by 24  
14 (supervisory employees are paid twice a month). This resulted in an  
15 annualized supervisory payroll of \$5,908,496. Next I added the actual  
16 permanent part-time and summer payroll of \$178,594 and \$66,140  
17 respectively, the payroll not subject to wage increases of \$476,900 and the  
18 actual overtime payroll for all non-salaried employees of \$556,513 for the  
19 twelve months ended January 31, 2006.

20 The sum of the clerical, bargaining group and supervisory, plus the  
21 Other Annualized Payroll equals a total normalized labor cost for the twelve  
22 months ended January 31, 2006 of \$18,615,535 (Column 5).

23 I then multiplied this total by 77%, (Factor A; Exhibit No. 13 Schedule

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 4), the portion of payroll expensed to Operation and Maintenance for the  
2 historical test year, to arrive at a Pennsylvania Division payroll Operation  
3 and Maintenance Expense of \$14,333,960.

4 Q. Why did you use the pay periods ending January 14, 2006 and January 31,  
5 2006?

6 A. Those pay periods were chosen because they reflect pay rates currently in  
7 effect as of the time of preparation of the rate filing and they include all  
8 changes to the payroll throughout the twelve months ended January 31,  
9 2006.

10 Q. Please describe Exhibit No. 4 Schedule 2 (NYD Labor) Page 3.

11 A. The purpose of Exhibit No. 4 Schedule 2 (NYD Labor) Page 3 is to adjust  
12 labor charges for New York Division employees providing service to the  
13 Pennsylvania Division, by annualizing the effects of a contractual wage rate  
14 increase of 2.75% that became effective in February 2005 and the 2.5%  
15 contractual increase effective February 12, 2006. The total labor charged to  
16 the Pennsylvania Division from the New York Division during the twelve  
17 months ended January 31, 2006 was \$3,379,319. This exhibit provides the  
18 adjustment of \$3,042 for the contractual February 2005 increase and  
19 \$82,004 for the contractual February 2006 increase to the historic test year  
20 and results in a normalized amount of \$3,464,365 for the Pennsylvania  
21 Division.

22 Q. Please describe Exhibit No. 4 Schedule 2 (SUP Labor) Page 4.

23 A. Exhibit No. 4 Schedule 2 (SUP Labor) Page 4 adjusts labor charged to the

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 Pennsylvania Division by employees of Supply to reflect a contractual 2.75%  
2 wage rate increase that became effective in May 2005 and the contractual  
3 2% wage increase effective April 30, 2006. The labor charges from the  
4 Supply to the Pennsylvania Division for the twelve months ended January  
5 31, 2006 were \$1,259,818. This exhibit provides the adjustment of \$9,396  
6 for the contractual May 2005 increase and \$25,384 for the contractual April  
7 2006 increase to the historic test year and results in a normalized amount of  
8 \$1,294,598 for the Pennsylvania Division.

9 When the direct Pennsylvania Division expense labor of \$14,333,960  
10 is added to the labor from New York of \$3,464,365 and the labor from the  
11 Supply of \$1,294,598, the result is the total normalized labor of \$19,092,923.  
12 The difference between the \$19,092,923 normalized payroll, and the actual  
13 payroll expense per books of \$18,668,323 is \$424,600. This is the  
14 adjustment to Labor Expense.

15 Q. Please describe Exhibit No. 4 Schedule 2 (Benefits.)

16 A. Exhibit No. 4 Schedule 2 (Benefits) Pages 6 - 14, shows the adjustment to  
17 the Operation and Maintenance Expenses of the Pennsylvania Division for  
18 employee benefits. Page 6 summarizes these adjustments. I will describe  
19 the changes found on pages 7 - 10 and 13 - 14. Mr. Bauer will address the  
20 adjustments on Pages 11 - 12.

21 Q. Please explain the adjustment to Group Life Insurance on Exhibit No. 4  
22 Schedule 2 (Benefits) Page 7.

23 A. The Company provides Term Insurance and Accident, Dismemberment and

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 Disability (AD&D) Insurance for its management and union employees. The  
2 Term Insurance rate is \$0.161 / \$1,000. Management employees' coverage  
3 is 2 times their salary (as found in Exhibit 4 Schedule 2 (PAD Labor) Page 2  
4 column (5), non management non supplemental employees' coverage is  
5 \$50,000 per person and supplemental employee's coverage is \$25,000 per  
6 person. The AD&D Insurance Rate is \$0.025 / \$1,000 and is based on the  
7 same calculation. These rates will change effective June 1, 2006 and will be  
8 updated in this proceeding. The Company also carries a blanket travel plan  
9 at \$339 per month. The addition of these three plans is \$4,853 per month or  
10 \$58,236 annually. Multiplying this gross annual by the 77% factor results in  
11 \$44,842 to Operations and Maintenance Expense for these three plans.  
12 Next, I added \$11,222 of per book Operation and Maintenance expense for  
13 the Officer Life Insurance plan which became effective January 1, 2005.  
14 This plan provides life insurance for officers who are over the age of 55, are  
15 not participants of the previous policy provided by the company and has a  
16 corporate ceiling of \$15,000 annually. The total of all the Group Life  
17 Insurance plans to Operations and Maintenance Expense is \$56,064 and  
18 provides for an normalizing adjustment of \$7,062 over the per book amount  
19 of \$49,002.

20 Q. Please explain the adjustment on Page 8.

21 A. This adjustment is for hospitalization expense. Hospitalization expense  
22 includes three components; health insurance, a Company provided wellness  
23 program and prescription drug coverage.

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1           The Company began to self-insure its health insurance in January  
2           2004. Employee benefits under the health care plan are the same as  
3           benefits under a Blue Cross and Blue Shield (BCBS) health care plan. The  
4           Company utilizes BCBS of Western New York, which is located in Buffalo,  
5           New York, as the Third Party Administrator ("TPA") and the Company uses  
6           the BCBS network of healthcare providers.

7           To accurately present the cost of the health self-insurance expense, I  
8           have reviewed the level of claims paid for the twelve months ended January  
9           2005 and for the twelve months ended January 2006. Between these  
10          twelve month periods, Distribution has experienced an increase in the  
11          average amount of claims paid per employees per month of 31.47%

12          Based upon a review of the rolling averages for twelve month periods  
13          ended each month from January 2005 through January 2006, the level of  
14          claims paid per employee per month is clearly increasing. Therefore, in  
15          order to adjust the level of expense for the twelve months ended January  
16          2006 to the annualized level of expense at January 2006, I applied one-half  
17          of the actual increase in claims paid per employee, or 15.74% ( $31.47\% \div 2$ ),  
18          to the average claims paid per employee per month for the twelve months  
19          ended January 2006 of \$487.25. This produces a level of claims paid per  
20          employee per month at the January 2006 level of operations of \$563.94. To  
21          this amount, I added the actual administrative charge from BCBS of \$35.98  
22          per employee per month to produce the monthly cost of self-insured health  
23          benefits per employee of \$599.92, as of the end of the historic test year.

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 To project Hospitalization costs, I have multiplied the annualized cost  
2 per month per employee of \$599.92 by the number of participating active  
3 employees to calculate the monthly amount. To annualize, this amount is  
4 multiplied by 12 for a total of \$2,469,271.

5 The Pharmaceutical Card System (PCS) rate per employee was  
6 calculated similar to the Health Insurance rate. Specifically, I reviewed the  
7 level of claims each month for twelve-month periods from January 2005  
8 through January 2006. Between these twelve-month periods, Distribution  
9 has experienced an increase in the average amount of claims paid per  
10 employees per month of 7.72%

11 To provide the level of expense for the twelve months ended January  
12 2006 to the annualized level of expense at January 2006, I applied one-half  
13 of the actual increase in claims paid per employee, or 3.86% ( $7.72\% \div 2$ ), to  
14 the average claims paid per employee per month for the twelve months  
15 ended January 2006 of \$200.72. This produces a level of claims paid per  
16 employee per month at the January 2006 level of operations of \$208.47. To  
17 this amount, I added the actual administrative charge from BCBS of \$0.50  
18 per employee per month to produce the monthly cost of self-insured health  
19 benefits per employee of \$208.97, as of the end of the historic test year.

20 This is then multiplied by the number of participating employees and  
21 annualized for a total of \$832,536. Finally, \$888 for the Wellness Program  
22 was added.

23 The total normalized annual cost for these health care programs is

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1       \$3,302,695. The total annualized supervisory and weekly contributions  
2       towards Hospitalization were subtracted to arrive at a total normalized cost  
3       of \$3,111,818. This was multiplied by Factor A to calculate the amount to be  
4       charged to Operation and Maintenance Expense of \$2,396,100. When the  
5       actual expense of \$1,868,916 for the twelve months ended January 31,  
6       2006 is subtracted, a normalizing adjustment of \$527,184 is produced.

7    Q.    Please explain the adjustment on Exhibit No. 4 Schedule 2 (Benefits) Page  
8       9.

9    A.    Exhibit No. 4 Schedule 2 (Benefits) Page 9 adjusts the Pennsylvania  
10       Division Operation and Maintenance Expense for the twelve months ended  
11       January 31, 2006 for the cost of the 401(k) Plan. First, I annualized the  
12       payment for the 401(k) Plan using the February 2006 actual payments.  
13       Payments are updated for payroll changes in February and August therefore  
14       the February payments were compared to January 2006 payrolls which  
15       included the recent payroll increases. The 401(K) payment to payroll  
16       percentage by payroll type was then used to calculate the payment for the  
17       normalized twelve months ended January 31, 2006. I then multiplied the  
18       annualized 401(k) Plan by Factor A to determine the portion to be expensed  
19       of \$454,824. Next, I subtracted \$481,612, the amount charged to the  
20       Pennsylvania Division expense per books. This resulted in an adjustment of  
21       (\$26,788).

22   Q.    Please explain the adjustment on Exhibit No. 4 Schedule 2 (Benefits) Page  
23       10.

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 A. Exhibit No. 4 Schedule 2 (Benefits) Page 10 adjusts the Pennsylvania  
2 Division Operation and Maintenance Expense for the twelve months ended  
3 January 31, 2006 for the cost of the Dental Plan. The adjustment starts with  
4 the actual gross of \$249,503 and does not project an increase to the gross.  
5 It is then multiplied by Factor A to determine the portion to be expensed of  
6 \$192,117. Next, I subtracted \$175,763, the amount charged to the  
7 Pennsylvania Division expense per books. This resulted in an adjustment of  
8 \$16,354.

9 Q. Please explain the adjustment on Exhibit No. 4 Schedule 2 (Benefits) Page  
10 13.

11 A. Exhibit No. 4 Schedule 2 (Benefits) Page 13 adjusts the Pennsylvania  
12 Division Operation and Maintenance Expense for the twelve months ended  
13 January 31, 2006 for the cost of the Retirement Savings Plan. The  
14 Company provides a Retirement Savings Account (RSA) for employees  
15 hired after July 1, 2003. The benefit is 2% of the employee's salary for fewer  
16 than 8 years of service and 3% for 8 years and more of service and is  
17 received 12 months after hire date. I have calculated by employee group by  
18 hire year the average monthly labor expense. Since all employees are  
19 currently at the 2% contribution level, I have applied 2% to the average  
20 monthly labor expense and multiplied this by 12 for an annual gross RSA of  
21 \$8,321. It is then multiplied by Factor A to determine the portion to be  
22 expensed of \$6,407. Next, I subtracted \$6,100, the amount charged to the  
23 Pennsylvania Division expense per books. This resulted in an adjustment of

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1           \$307.

2    Q.    Please explain the adjustment on Exhibit No. 4 Schedule 2 (Benefits) Page  
3           14.

4    A.    This exhibit adjusts benefit charges associated with labor charged from the  
5           New York Division and Supply to the annualized level for the twelve months  
6           ended January 31, 2006, based on the fiscal 2006 loading factor. As labor  
7           dollars from other jurisdictions are charged to the Pennsylvania Division (as  
8           outlined in Exhibit 4 Schedule 2 (NYD Labor) and (SUP Labor)), a  
9           corresponding charge is made for the associated benefits. The New York  
10          Division loading factor for fiscal 2006 is 98.3%. The normalized labor from  
11          the New York Division was multiplied by the benefit loading factor to  
12          compute the normalized benefits charged from the New York Division. The  
13          Supply loading factor for fiscal 2006 is 88.9%. The normalized labor from  
14          the Supply was multiplied by the benefit loading factor to compute the  
15          normalized benefits charged from Supply.

16   Q.    Please describe Exhibit No. 4 Schedule 2 (Rent) Page 15.

17   A.    Rent expense includes the leasing of office space for the Pennsylvania  
18          Division as well as an allocation of space associated with personnel  
19          completing work for the Pennsylvania Division. This allocated space  
20          includes Distribution's Main Office located in Williamsville, New York. I have  
21          multiplied the January 2006 monthly rate by 12 to calculate an annualized  
22          rent expense of \$665,590. Next, I subtracted \$621,909, the amount  
23          charged to the Pennsylvania Division expense per books. This resulted in

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 an adjustment of \$43,681.

2 Q. Please describe Exhibit No. 4 Schedule 2 (Transportation Clearing) Page  
3 16.

4 A. This Exhibit outlines the changes to the Transportation Clearing Account for  
5 changes to cost elements that are outlined in the Operation and  
6 Maintenance Exhibit No. 4 Schedule 1 Page 2. For example, Pennsylvania  
7 labor was changed by 2.17% as calculated on Exhibit No. 4 Schedule 2  
8 (Labor) Page 1.

9 The Transportation Clearing Account is used to accumulate the  
10 charges of maintaining the Company's fleet of vehicles. The labor,  
11 materials, and equipment rental costs for fleet maintenance are collected in  
12 the accounts 184000 and 184500 as shown in the top half of the exhibit.  
13 The total charges into the accounts for the twelve months ended January 31,  
14 2006 were \$2,903,338. The clearing account is then forecasted using the  
15 changes outlined in Exhibit No. 4 Schedule 1 Page 2 for a total normalized  
16 of \$1,170,376 for Account 184000 and \$1,764,787 for Account 184500. The  
17 specific adjustments are outlined within the footnotes.

18 Since this clearing account services vehicles that can be used for  
19 construction work as well as vehicles used for reading meters, the account is  
20 cleared via the workload vehicle hours. For example, if 35% of the vehicle  
21 hours were used for construction work, 35% of the Transportation Clearing  
22 Account would be cleared to a construction account.

23 The bottom half of the exhibit outlines the Charges Distributed from

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 the Clearing Account including both O&M Accounts (Accounts 401000 –  
2 402000) and non O&M Accounts (Accounts 107000 – 426400). The amount  
3 charged to O&M Expense for the twelve months ended January 31, 2006  
4 was \$2,172,241. The normalized January 31, 2006 calculates to \$2,202,316  
5 or \$30,075 more than the per books expense amount.

6 Q. Please explain Exhibit No. 4 Schedule 2 (Telephone Clearing) Page 17.

7 A. The Telephone Clearing Account is used to accumulate the costs incurred to  
8 provide telecommunication services to the Company. The exhibit is set up  
9 similarly to the Transportation Clearing account with the Clearing Account  
10 per books and forecasted on the upper half of the exhibit and the charges  
11 distributed on the lower half. For the twelve months ended January 31,  
12 2006 the total clearing account was \$1,178,739 with \$864,013 being  
13 expensed of which \$355,284 was expensed to the Pennsylvania Division.  
14 Again using the normalized forecast found in Exhibit No. 4 Schedule 1 Page  
15 2 the normalized amount to the Pennsylvania Division Operation and  
16 Maintenance Expense is \$362,159 or \$6,875 more than the per books  
17 expense amount.

18 Q. Please explain the adjustments to Office Employee Expense and Dues  
19 Expense.

20 A. As provided in NFG 2-30, \$21,611 of contribution and donations were  
21 incorrectly coded as dues and memberships. Of this amount, \$4,256 should  
22 have been coded Office Employee Expense. I have removed in total  
23 \$21,611 from cost element Dues and have reclassified for ratemaking

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1       purposed \$4,256 to cost element Office Employee Expense. The remaining  
2       \$17,355 has been removed from Operation and Maintenance Expense for  
3       ratemaking purposes.

4    Q.    Please explain Exhibit No. 4 Schedule 2 (Meter Shop Clearing) Page 18.

5    A.    The Meter Shop Clearing account accumulates charges for testing and  
6       maintaining gas meters. For the twelve months ended January 31, 2006 the  
7       total clearing account was \$1,070,373 of which \$414,361 was expensed to  
8       the Pennsylvania Division. The normalized forecast of the clearing account  
9       is \$1,233,519 of which \$477,518 is expensed to the Pennsylvania Division  
10      or \$63,157 higher than the per books expense amount.

11   Q.    Please explain the adjustment to Customer Education Amortization.

12   A.    Distribution's Restructuring Settlement (R-994785) provided for the  
13      collection of dollars spent on customer education applicable to restructuring.  
14      The Company collects these dollars via a tariff rider and expenses the  
15      amount spent on a fiscal basis. Since the education dollars are not reflected  
16      in revenues, the \$4,133 expense has been removed.

17   Q.    Please explain Exhibit No. 4 Schedule 2 (PPUC) Page 19.

18   A.    Exhibit No. 4 Schedule 2 (PPUC) Page 19 outlines a normalizing adjustment  
19      of \$99,992 to the twelve months ended January 31, 2006. The company  
20      received a General Assessment Invoice dated 8/17/2005 in the amount of  
21      \$912,579 for the fiscal year July 1, 2005 – June 30, 2006. The company  
22      received a Supplemental Assessment dated 1/27/2006 in the amount of  
23      \$27,879 for the fiscal year July 1, 2005 – June 30, 2006. This equates to a

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 total assessment of \$940,458 which is \$99,992 higher than the per book  
2 amount of \$840,466 for the twelve months ended January 31, 2006.

3 Q. Please explain Exhibit No. 4 Schedule 2 (Other Insurance) Page 20.

4 A. Exhibit No. 4 Schedule 2 (Other Insurance) Page 20 outlines the \$46,863  
5 adjustment to the twelve months ended January 31, 2006 for the known  
6 policy renewals in April 2006, which are amortized monthly over the life of  
7 the specific policy. The renewals effective April 2006 equal \$554,491 or  
8 \$46,863 higher than what was expensed for the twelve months ended  
9 January 31, 2006.

10 Q. Please explain Exhibit No. 4 Schedule 2 (Postage) Page 21.

11 A. A general 5.4% postage rate increase was effective January 8, 2006. I have  
12 normalized the twelve months ended January 31, 2006 per book amount of  
13 \$84,859 to reflect 342 days (or 5.06%) of this increase. This calculates to a  
14 normalized twelve months ended January 31, 2006 expense of \$89,153.

15 Q. Please explain Exhibit No. 4 Schedule 2 (ISD Clearing) Page 22.

16 A. The ISD Clearing account accumulates costs associated with the service of  
17 providing computer technology to the Company. For the twelve months  
18 ended January 31, 2006 the clearing account total was \$12,141,585 of  
19 which \$2,749,229 was expensed to the Pennsylvania Division. Forecasting  
20 the clearing account for changes found in Exhibit No. 4 Schedule 1 Page 2  
21 equals \$13,043,057 of which \$2,965,171 is expensed to the Pennsylvania  
22 Division Operating and Maintenance Expense.

23 Q. Please explain Exhibit No. 4 Schedule 2 (Contract Admin. Clearing) Page

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 23.

2 A. The Contract Administration Clearing account accumulates the costs  
3 associated with the contracting of gas supply for the Distribution  
4 Corporation. The clearing account at January 31, 2006 was \$1,503,537 of  
5 which \$479,472 was expensed to the Pennsylvania Division. Forecasting  
6 the clearing account for changes found in Exhibit No. 4 Schedule 1 Page 2  
7 equals \$1,638,567 of which \$523,195 is expensed to the Pennsylvania  
8 Division Operating and Maintenance Expense.

9 Q. Please explain Exhibit No. 4 Schedule 2 (Customer Billing Clearing) Page  
10 24.

11 A. The Customer Billing Clearing Account accumulates the costs incurred to bill  
12 customers for natural gas service and other notifications and includes the  
13 cost of postage. The clearing account at January 31, 2006 was \$3,545,959  
14 of which \$1,028,328 was expensed to the Pennsylvania Division.  
15 Forecasting the clearing account for changes found in Exhibit No. 4  
16 Schedule 1 Page 2 plus an the general postage increase of 5.4% equals  
17 \$3,692,623 of which \$1,070,861 is expensed to the Pennsylvania Division  
18 Operating and Maintenance Expense.

19 Q. Please explain the adjustment to the LIURP cost element.

20 A. In Distribution's rate case R-038168, a settlement was reached which  
21 outlined, among several things, that the LIURP funding would be set at a  
22 constant amount specifically \$1,183,566. An adjustment of (\$412,127) to  
23 the historic test year of \$1,595,693 has been made to represent the

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Direct Testimony of Ruth M. Friedrich-Alf

1 settlement amount.

2 Q. Please describe Exhibit No. 4 Schedule 2 (Customer Deposit) Page 25.

3 A. The adjustment of \$190,455 to the historic test year is to reflect the interest  
4 expense on the Customer Deposit rate base credit. The adjustment is in  
5 compliance with the Commission's Order at R-891218 whereby the  
6 Company's rate base was reduced for the average balance in Account  
7 235000 - Customer Deposits. The \$190,455 adjustment is to reflect the  
8 *interest expense for ratemaking purposes associated with the rate base*  
9 *adjustment of (\$3,174,247) as outlined on Exhibit No. 8 Schedule 5 Page 1.*

10 The interest rate, 6% is based on 66 AP.C.S. § 1404(c)(6)..

11 Q. Please explain Exhibit No. 4 Schedule 2 (Remittance Clearing) Pages 26  
12 and 27.

13 A. The Remittance Clearing Account accumulates costs associated with the  
14 remitting of customer payments. Page 26 summarizes the per book amount  
15 of \$573,465 of which \$166,305 was expensed to the Pennsylvania Division  
16 Operation and Maintenance expense. Page 27 incorporates the changes to  
17 the account for those outlined in Exhibit No. 4 Schedule 1 Page 2. The  
18 normalized clearing account is \$628,877 of which \$182,374 is expensed to  
19 the Operation and Maintenance Expense of the Pennsylvania Division.

20 Q. Please explain Exhibit No. 4 Schedule 2 (Gas Transportation Clearing)  
21 Pages 28 and 29.

22 A. The Gas Transportation Clearing account accumulates costs incurred to  
23 manage the gas measurement and transportation customer support services

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 provided by the Company. Page 28 outlines January 31, 2006 per books of  
2 \$2,361,558 of which \$718,804 was expensed to the Pennsylvania Division.  
3 Page 29 incorporates changes outlined in Exhibit No. 4 Schedule 1 Page 2  
4 which amounts to normalized clearing account of \$2,574,420 of which  
5 \$783,594 is expensed to the Pennsylvania Division Operation and  
6 Maintenance Expense.

7 Q. Please explain Exhibit No. 4 Schedule 2 (GTI) Page 30.

8 A. In Distribution's rate case R-049656, a settlement was reached which  
9 outlined, among several things, that the GTI amortization to expense would  
10 be set at an annual amount of \$526,466. An adjustment of \$209,112 to the  
11 historic test year of \$317,354 has been made to represent a full twelve  
12 months of the settlement amount.

13 Q. Please explain Exhibit No. 4 Schedule 3 Pages 1 –7.

14 A. Exhibit No. 4 Schedule 3 Page 1 shows the ratemaking cost elements per  
15 books for the twelve months ended January 31, 2005 and January 31, 2006  
16 and the increase / (decrease) to the cost element. Pages 2 through 6  
17 provide a description of the cost elements and the major reason for the  
18 increase / (decrease) for significant changes are identified.

19 Q. Please describe the remaining schedules in Exhibit No. 4 that you are  
20 sponsoring.

21 A. Exhibit No. 4 Schedule 4 addresses the regulation responding to the  
22 amortization of rate case expense. Exhibit No. 4 Schedule 5 addresses  
23 regulations responding to labor and benefits. Exhibit No. 4 Schedule 6 is

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 National Fuel's Actuarial Report for FAS Statement No. 87 for Accounting  
2 Period Beginning October 1, 2004 and Ending September 30, 2005 as  
3 prepared by Mercer dated October 2005. Exhibit No. 4 Schedule 7 is  
4 National Fuel's Postretirement Benefit Valuation Report Under SFAS 106  
5 and 132(R) Disclosures for Fiscal Year ending September 30, 2005 dated  
6 November 2005 as prepared by Mercer. Exhibit No. 4 Schedule 8  
7 addresses the statute requirements concerning expenditures for advertising.  
8 Exhibit No. 4 Schedule 9 addresses the filing requirement on research and  
9 development expenditures. Exhibit No. 4 Schedule 10 addresses the filing  
10 requirement regarding the Company's labor productivity.

11 Q. Please describe Exhibit No 6 Schedule 1 Page 1.

12 A. Exhibit No. 6 Schedule 1 Page 1 provides a summary of the Taxes Other  
13 Than Income Taxes at January 31, 2006 (column (1)) and normalized at  
14 January 31, 2006 in column (3). The total per books for the twelve months  
15 ended January 31, 2006 was \$1,714,331. Adjusting the individual  
16 components as described below amounts to an addition of \$377,647 for a  
17 normalized twelve months ended January 31, 2006 of \$2,091,978.

18 Q. Please describe the adjustment to FICA tax.

19 A. Exhibit No. 6 Schedule 1 Page 2 outlines the FICA Base and Medicare tax  
20 as it corresponds to the adjustment in Pennsylvania labor found in Exhibit  
21 No. 4 Schedule 2 (PAD labor). The total FICA tax rate for calendar 2006 is  
22 7.65% up to an earnings cap of \$94,200. The total per book Operation and  
23 Maintenance Expense FICA tax for the twelve months ended January 31,

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 2006 was \$1,014,000 and the total Operation and Maintenance Expense per  
2 book labor was \$14,029,186. This equates to a factor of 7.22278 FICA  
3 O&M tax to O&M Labor ( $\$1,014,000 / \$14,029,186 = 7.2278\%$ .)  
4 Referencing the normalized PAD labor of \$14,333,960 multiplied by the  
5 7.2278 historic percentage calculates a normalized FICA tax of \$1,036,030  
6 or \$22,030 more than the per book amount.

7 Q. Please explain Exhibit No. 6 Schedule 1 Page 3.

8 A. Exhibit No. 6 Schedule 1 Page 3 outlines the Company's responsibility of  
9 State Unemployment and Federal Unemployment amounts to operation and  
10 maintenance expense.

11 Calendar 2006 Pennsylvania State Unemployment rate is 2.3152%  
12 capped at \$8,000 per person. Multiplying \$8,000 by the applicable rate of  
13 2.3152% by the number of employees calculates a gross amount of  
14 \$63,529. Applying Factor A achieves a normalized operation and  
15 maintenance expense amount of \$48,917 or \$13,579 more than per book  
16 amount of \$35,338.

17 Calendar 2006 Federal Unemployment rate is 0.8% capped at \$7,000  
18 per person. Multiplying \$7,000 by the applicable rate of 0.8% by the number  
19 of employees calculates a gross amount of \$19,208. Applying Factor A  
20 achieves a normalized operation and maintenance expense amount of  
21 \$14,7908 or \$1,392 less than per book amount of \$16,182.

22 Q Please explain Exhibit No. 6 Schedule 1 Page 4.

23 A. Exhibit No. 6 Schedule 1 Page 4 outlines the Public Utility Realty Tax

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 (PURTA) and Capital Stock Tax Liability. The estimated PURTA liability is  
2 calculated by multiplying the state taxable value at December 31, 2005 by  
3 the current realty tax rate of 2.82254%. This will be updated for the  
4 valuation due May 1, 2006 if the liability changes. The Capital Stock Tax  
5 calculation has been calculated using the 2004 return and 2005 allocation  
6 percentage. The 2005 rate of 0.599% has been applied to calculate a  
7 liability of \$866,404 or \$345,682 higher than the historic test year of  
8 \$520,722.

9 Q. Please describe Exhibit No. 8 and the associated schedules.

10 A. Exhibit 8 Schedule 1 provides a summary of rate base by rate base  
11 component for the twelve months ended January 31, 2006 per books and  
12 normalized. Exhibit No. 8 Schedule 2 provides plant in service, Exhibit No. 8  
13 Schedules 3 and 4 calculates the working capital requirement. Schedule 4  
14 is sponsored by Ms. Truitt. Exhibit No. 8 Schedule 5 provides the customer  
15 deposit reduction to rate base in compliance with the Commission's Order at  
16 R-891218 whereby the Company's rate base was reduced by the average  
17 balance in Account 235000 - Customer Deposits. I note that interest  
18 expense for customer deposits is shown on Exhibit No. 4 Schedule 2  
19 (Customer Deposits). Exhibit No. 8 Schedule 6 which is sponsored by Mr.  
20 Malachowski, provides the Deferred Income Tax calculation and Exhibit No.  
21 9 which is sponsored by Mr. Spanos, provides the Accrued Depreciation  
22 calculation.

23 Q. Please describe Exhibit No. 8 Schedule 2 Page 1.

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 A. Exhibit No. 8 Schedule 2 provides the gas plant in service per books  
2 (Account 101000) at January 31, 2006 of \$416,501,273. The next  
3 calculation adjusts the plant in service to include \$1,294,548 for Completed  
4 Not Classified Construction Work In Progress (old account 106000) and  
5 \$896,700 of Construction Work In Progress (Account 107000) at January  
6 31, 2006 for a total plant in service of \$418,692,521. The amount of  
7 \$1,294,548 represents projects completed and in service however they have  
8 not yet been classified on the books and records of the Company. The  
9 amount \$896,700 represents expenditures made at January 31, 2006 on  
10 projects that will be put in service during the future test year.

11 Q. Please describe Exhibit No. 8 Schedule 2 Page 2.

12 A. Exhibit No. 8 Schedule 2 Page 2 provides the analysis of determining  
13 revenue producing CWIP. This analysis will be used in determining rate  
14 base for the future test year at January 31, 2007.

15 Transmission Plant Account 367 Transmission Lines has several  
16 different designations embedded within (appropriations 315A through 315E).  
17 The Company uses appropriation numbers to provide further detail of the  
18 FERC Accounts. Appropriation 315A Transmission Lines Extensions are  
19 revenue producing. At January 31, 2006, no dollars in Account 107000  
20 were associated with new Transmission lines. Normally associated with  
21 Transmission extensions are new Measurement and Regulator Stations  
22 (delineated as part of Appropriation 325X). There was \$4,500 in Account  
23 369 at January 31, 2006 however since there were no dollars in

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Direct Testimony of Ruth M. Friedrich-Alf

1 Appropriation 315A work at January 31, 2006, the \$4,550 in Account 369 is  
2 not considered to be revenue producing but work associated with a non-  
3 revenue producing Transmission project.

4 Distribution Plant has several revenue producing appropriations. The  
5 first is appropriation 415A Customer Extensions Mains which is located  
6 within Account 376 Mainlines. All of appropriation 415A (\$31,514) is  
7 revenue producing. Appropriation 415A represents 12.50% of Account 376  
8 Mainlines. Account 378 Measurement and Regulator Stations is inter-  
9 related with Account 376 so 12.50% of Account 378 (appropriation 425X) or  
10 \$2,577 as revenue producing. Account 380 Services (appropriation 452X  
11 new services) is also revenue producing, but no dollars for Account 380  
12 Appropriation 452X were in Account 107000 at January 31, 2006. Account  
13 381 Measurement and Regulator Equipment (Appropriation 455X Automatic  
14 Meter Reading Devices) is inter-related with Account 380 Services and  
15 would be the same percentage as appropriation 452. Account 385 Industrial  
16 Measurement and Regulator Stations (appropriation 470X New Stations)  
17 \$37,691 was revenue producing. The total revenue producing construction  
18 work in progress for both Transmission Plant and Distribution Plant at  
19 January 31, 2006 was \$71,782. On average, the company experiences a  
20 30 day delay between the time the dollars are expended until the dollars are  
21 booked to plant. With this premise, all amounts expended as of January 31,  
22 2006 on construction work in progress, both revenue producing and non-  
23 revenue producing plant was included in the Total Adjusted Plant In Service

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 amount of \$418,692,521.

2 In summary the adjusted plant in service as outlined on Exhibit No. 8

3 Schedule 2 Page 1 is as follows:

4

Account 101000	Plant In Service	\$416,501,273
Account 106000	Completed Not Classified	1,294,548
Account 107000	Revenue Producing CWIP	71,782
Account 107000	Non Revenue Producing CWIP	<u>824,918</u>
Adjusted Plant In Service at 1/31/2006		<u>\$418,692,521</u>

5

6 Q. Please describe Exhibit No. 8 Schedule 3 Page 1.

7 A. Exhibit No. 8 Schedule 3 Page 1 sets forth the monthly balances of the  
8 components of the working capital claim. Column (1) is the Materials and  
9 Supplies balance. This includes the cost of warehouse inventories and  
10 related costs and expenses incurred in the operation of the general  
11 storerooms and warehouses. The rate base working capital for materials  
12 and supplies is the 13 month average of \$1,106,482. Column (2) represents  
13 the monthly balances for the PPUC Assessment, which is paid annually and  
14 amortized over the succeeding 12 months. Column (3) is the monthly  
15 balance of Other Insurance premiums paid (in April) and amortized over the  
16 period of the coverage. Column (4) is the AGA Dues balance which are paid  
17 quarterly and expenses are accrued over a three month period. Column (5)  
18 totals columns (2) through (4). The rate base working capital for these three

National Fuel Gas Distribution Corporation  
Direct Testimony of Ruth M. Friedrich-Alf

1 expenses is the 13 month average of \$535,508. Column (6) provides the  
2 monthly balance for Distribution's gas storage inventory. In Distribution's  
3 rate case at Docket No. R-942991, the Commission adopted a 12 month  
4 average for gas stored underground working capital. Use of a 13 month  
5 average was rejected because including the same month twice would cause  
6 distortions due to the seasonal nature of the storage operations. The 12  
7 month average working capital ( $\frac{1}{2}$  of Jan. 2005 +  $\frac{1}{2}$  Jan. 2006 + average  
8 (February 2005 through December 2005)) for the period ended January 31,  
9 2006 is \$9,042,940.

10 Q. Please describe Exhibit No. 8 Schedule 5 Page 1.

11 A. Exhibit No. 8 Schedule 5 Page 1 is the calculation of the average customer  
12 deposit balance which is a reduction to rate base. The thirteen month  
13 average working capital for customer deposits is (\$3,174,274).

14 Q. Please describe Exhibit No. 13.

15 A. Exhibit No. 13 contains miscellaneous filing requirements and calculations of  
16 factors that are used to calculate Distribution's revenue requirement.

17 Q. Does this conclude your testimony?

18 A. Yes, at this time.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF PAUL L. MALACHOWSKI

1 Q. Please state your name and address.

2 A. My name is Paul L. Malachowski and my business address is 6363 Main  
3 Street, Williamsville, New York.

4 Q. What is your present position?

5 A. I am Senior Manager of Tax Services for National Fuel Gas Distribution  
6 Corporation.

7 Q. Will you outline your educational and your business experience?

8 A. I graduated from Canisius College in 1977 with a Bachelor of Science  
9 Degree in Accounting. I was certified by New York State as a Certified  
10 Public Accountant in 1979. I was first employed by the Buffalo office of  
11 Arthur Young and Company in June 1977 as a Staff Accountant. I  
12 subsequently served as Senior Accountant, Audit Manager, and Tax  
13 Manager with this firm until 1985. In 1985 I was employed by Goldome  
14 Bank as Deputy Auditor until 1989. In 1989, I was employed by National  
15 Fuel Gas Distribution as Chief Auditor. In 1994, I became a Senior  
16 Manager in the Finance Department and was responsible for capital  
17 structure and cost of debt testimony for various rate cases. In 2000, I  
18 was assigned to an internal group tasked with evaluating new business  
19 opportunities. In January 2006, I became Senior Manager of Tax  
20 Services, the position that I presently hold.

21 Q. As Senior Manager of Tax Services, what are your duties for the  
22 Company?

23 A. I am responsible for managing the Tax Department. Among my

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DIRECT TESTIMONY OF PAUL L. MALACHOWSKI

1 responsibilities are the computation and payment of taxes incurred by  
2 the companies in the National Fuel System. I compile and compute data  
3 concerning taxes for various departments in the company, consultants,  
4 taxing agencies, auditors and the regulatory commissions. I am required  
5 to keep records of various tax expenditures, compile information for rate  
6 cases, and assist other departments in conforming to changes in the tax  
7 laws.

8 Q. I show you what has been identified as Exhibit No. 7, Schedule 1, page  
9 1 and ask you to explain the exhibit.

10 A. Exhibit No. 7, Schedule 1, Page 1 is a summary of current income taxes  
11 and deferred income taxes at present and proposed rates, as adjusted  
12 for ratemaking purposes, for the twelve months ended January 31, 2006.

13 Q. I show you what has been identified as Exhibit No. 7, Schedule 1, page  
14 2 and ask you to explain this exhibit.

15 A. Exhibit No. 7, Schedule 1, page 2 shows the calculation of federal and  
16 state income taxes at existing rates and at proposed rates.

17 The starting point for the calculation of federal and state income  
18 taxes was the operating income before income taxes, at present rates  
19 and at proposed rates. From such amounts, additional adjustments  
20 were made in order to derive the income subject to income taxes at  
21 present and proposed rates.

22 The first adjustment is the deduction of interest expense as  
23 calculated on Exhibit No. 7, page 1 in the amount of \$8,558,000.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF PAUL L. MALACHOWSKI

1 Interest expense is calculated by multiplying the Pennsylvania Division  
2 rate base times the debt ratio and embedded cost of debt used in the  
3 rate of return calculation.

4 The second adjustment is a meals/entertainment adjustment of  
5 \$31,000 to increase operating income before income taxes in arriving at  
6 taxable income.

7 The third adjustment in the amount of \$4,532,000 is the additional  
8 depreciation allowed for Pennsylvania Income Tax purposes in excess of  
9 the annual accrual for rate making. This amount does not include the  
10 federal bonus depreciation, which is disallowed for Pennsylvania Income  
11 Tax.

12 The preliminary income subject to the Pennsylvania Corporate  
13 Net Income Tax is \$15,420,000 at existing rates and \$43,058,000 at  
14 proposed rates. Pennsylvania Corporate Net Income Tax is then  
15 computed at the statutory rate of 9.99%.

16 After deducting the respective amounts of the Pennsylvania  
17 Corporate Net Income Tax of \$1,540,000 and \$4,301,000 at existing  
18 rates and at proposed rates, the amounts of net income, before federal  
19 income tax, are \$13,880,000 and \$38,757,000 at existing rates and at  
20 proposed rates, respectively.

21 An addition is then made for bonus depreciation of \$1,013,000 to  
22 arrive at income subject to federal income tax. The federal income tax  
23 rate of 35% is then applied in determining the amount of the federal

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF PAUL L. MALACHOWSKI

1 income tax of \$5,213,000 at existing rates and \$13,920,000 at proposed  
2 rates.

3 The amounts of the current Pennsylvania Corporate Net Income  
4 Tax and of the current Federal Income Tax, at existing rates and at  
5 proposed rates, are shown on Exhibit No. 7, Schedule 1, page 1, lines 1  
6 and 3.

7 Q. Why is an addition to federal income being made in order to reflect the  
8 impact of bonus depreciation on federal taxes?

9 A. Federal tax legislation allowed a 30% additional first year depreciation  
10 deduction (bonus) for qualified property acquired after September 10,  
11 2001 (and a 50% bonus for qualified property acquired after May 5,  
12 2003), and placed in service, in most cases, before January 1, 2005.  
13 The amount of bonus depreciation claimed on the asset is then  
14 deducted from the depreciable basis in calculating the amount of  
15 remaining "regular" federal tax depreciation available in the first and  
16 subsequent years.

17 Pennsylvania enacted Act 89 that does not recognize the 30% or  
18 50% bonus depreciation, but allows an additional tax deduction of 3/7 of  
19 the "regular" federal tax depreciation. Taxpayers are also allowed to  
20 deduct any remaining undepreciated basis in the last taxable year that  
21 the property is depreciated for federal tax purposes.

22 This difference between the Federal depreciation deductions and  
23 the Pennsylvania depreciation deductions generates a timing difference.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF PAUL L. MALACHOWSKI

1 The following example illustrates how this timing difference is created  
2 and eliminated:

3 Assume that Distribution acquired an asset for \$100,000 in 2003  
4 which was eligible for 50% bonus depreciation, and was subject to 7  
5 year MACRS. This asset would generate \$50,000 in bonus depreciation  
6 in 2003, plus the remaining \$50,000 depreciable basis would generate  
7 MACRS depreciation of \$7,145; \$12,245; \$8,745; \$6,245; \$4,465;  
8 \$4,460; \$4,465; and \$2,230 for 2003 – 2010, respectively.

9 In determining Pennsylvania taxable income, the \$50,000 bonus  
10 depreciation in 2003 would not be recognized, but state depreciation  
11 expense of \$3,062; \$5,248; \$3,748; \$2,676; \$1,914; \$1,911; \$1,914; and  
12 \$956 plus a remaining \$28,571; would be recognized in 2003 – 2010,  
13 respectively, in addition to the MACRS depreciation.

14 Since Schedule 1 of Exhibit 7 first derives Pennsylvania taxable  
15 income and then Federal taxable income, this example would be  
16 reflected on that Schedule by showing a deduction of \$46,938 (\$50,000  
17 minus \$3,062) in arriving at federal taxable income for 2003; and by  
18 showing additions of \$5,248; \$3,748; \$2,676; \$1,914; \$1,911; \$1,914;  
19 and \$29,527 in arriving at federal taxable income for 2004 – 2010.

20 Q. Refer to Exhibit No. 7, Schedule 1, page 1 and explain the reduction of  
21 federal income taxes, which results from amortization of the investment  
22 tax credit.

23 A. Federal Income Taxes are reduced by \$4,000 per Exhibit No. 7,

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DIRECT TESTIMONY OF PAUL L. MALACHOWSKI

1 Schedule 1, page 1. This represents the annual amortization of the  
2 investment credit applicable to eligible property installed prior to July 1,  
3 1974. Exhibit No. 7, page 19, is a statement showing the computation of  
4 this test year amortization. Option 2 treatment of the investment credit  
5 as provided by Section 46(f)(2) of the Internal Revenue Code, requires  
6 that deferred credits be amortized ratably over the life of the property as  
7 a reduction to the cost of service. The adjustment on Exhibit No. 7,  
8 Schedule 1, page 1 meets this requirement. Option 2 credits may not be  
9 deducted from rate base.

10 Q. Refer to Exhibit No. 7, Schedule 1, page 1 and explain the deferred  
11 income taxes in the amount of \$1,411,000 resulting from normalization  
12 of tax depreciation.

13 A. The amount of \$1,411,000 is calculated on Exhibit No. 7, pages 5  
14 through 17. Details are provided of accelerated and straight-line  
15 depreciation for the twelve months ended January 31, 2006, by vintage  
16 of property, from 1970 through 2006.

17 For 1970-vintage property, normalization is based upon the  
18 difference between straight-line tax depreciation, using guideline lives,  
19 and depreciation calculated using the sum of the years digits method  
20 and guideline lives. For property of vintages 1971 through 1980,  
21 normalization is based upon the difference between straight-line tax  
22 depreciation, using guideline lives, and depreciation calculated using the  
23 sum of the years digits method and class life Asset Depreciation Range

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF PAUL L. MALACHOWSKI

1 lives. For 1981 through 1986 vintages of property, deferred federal  
2 income taxes were computed, as required by Section 168(i) (9) of the  
3 Internal Revenue Code, based upon normalization of the difference  
4 between straight-line depreciation, computed by applying book rates to  
5 the tax basis of the property and tax depreciation using applicable  
6 Accelerated Cost Recovery System (ACRS) rates, under Section 168 of  
7 the Internal Revenue Code. Pursuant to the Tax Reform Act of 1986  
8 (TRA-86), modified ACRS depreciation is computed on property placed  
9 in service on and after January 1, 1987. TRA-86 requires the  
10 normalization of these depreciation deductions per Section 203(e) of the  
11 act.

12 Distribution must be permitted to normalize the federal tax effect  
13 of the difference between accelerated and straight-line depreciation on  
14 property installed in 1970 through 1980, because Distribution's  
15 predecessors used straight-line depreciation as their applicable method  
16 of depreciation for pre-1970 property and Distribution is therefore, not  
17 authorized by the Internal Revenue Code to deduct accelerated  
18 depreciation unless there is normalization. Normalization of the federal  
19 tax effect of the difference between accelerated and straight-line  
20 depreciation for property installed in 1981 and thereafter is required by  
21 the Economic Recovery Tax Act of 1981 and the Tax Reform Act of  
22 1986 (TRA-86). If Distribution is not permitted to recover the revenues  
23 necessary to provide for normalization of such tax effects, Distribution

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF PAUL L. MALACHOWSKI

1 will not be permitted to deduct accelerated depreciation for income tax  
2 purposes.

3 Q. I refer you to Exhibit No. 8, Schedule 6, page 1 and ask you to explain  
4 the amount shown for Accumulated Deferred Investment Tax Credit.

5 A. Exhibit No. 8, Schedule 6, page 1 presents a computation of the balance  
6 of the Accumulated Deferred Investment Credit as of January 31, 2006.  
7 The per books balance at January 31, 2006, for the Pennsylvania  
8 Division is developed on Exhibit No. 7, pages 20 through 24 by reducing  
9 the total amounts of all investment tax credits initially deferred by the  
10 amounts amortized through January 31, 2006, to produce the  
11 unamortized amount at January 31, 2006 of \$2,104,149. An adjustment  
12 is then made to deduct, from the balance of accumulated deferred  
13 investment credits, at January 31, 2006, the balance of accumulated  
14 deferred investment credits that are to be amortized under the Option  
15 Two provisions of the Internal Revenue Code.

16 Section 46(f) (formerly Section 46(e)) of the Internal Revenue  
17 Code set forth special requirements that must be met by a public utility  
18 that receives investment tax credits for income tax purposes. Under  
19 Section 46(f)(1) (Option 1), the utility's rate base may be reduced by the  
20 balance of accumulated deferred investment credits, provided that the  
21 balance is amortized (returned to rate base) ratably over the life of the  
22 property. Under Option 1, the credit may not be used to reduce the  
23 utility's cost of service or provision for income taxes for ratemaking

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF PAUL L. MALACHOWSKI

1 purposes. Option 1 treatment is used, for most of Distribution's property,  
2 and is the reason for the calculation on Exhibit No. 8, Schedule 6, page  
3 1 of the balance of investment credits to be deducted from rate base.

4 Section 46(f)(2) ("Option 2") is an alternative method of allowed  
5 ratemaking treatment for investment tax credits. Option 2 treatment is  
6 allowed only if the utility elected the provisions of Option 2 on, or before,  
7 March 9, 1972. Pennsylvania Gas Company ("PGC"), a predecessor of  
8 Distribution, did properly elect Option 2 and, thus, investment credits of  
9 the former PGC are reflected in Distribution's rate filing in accordance  
10 with the requirements of Option 2. Under Option 2, the rate base of the  
11 utility cannot be reduced by any portion of the investment credit.

12 However, the utility's cost of service may be reduced by amortizing the  
13 balance of investment credits ratably over the life of the property.

14 Distribution has reflected the allowed amortization of investment credits  
15 that are subject to Option 2 treatment, on Exhibit No. 7, page 19, and  
16 this amount is carried forward to Exhibit No. 7, Schedule 1, page 1.

17 However, because credits under Option 2 may not be deducted from  
18 rate base and because the per books balance of unamortized credits  
19 includes Option 2 credits, the unamortized balance of investment credits  
20 at January 31, 2006 that are subject to Option 2 treatment, in the  
21 amount of \$700, must be eliminated from the per book balance of  
22 accumulated deferred investment tax credits at January 31, 2006, that is  
23 to be deducted from rate base. The adjusted balance for the

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF PAUL L. MALACHOWSKI

1 Pennsylvania Division of \$2,103,449 is deducted in determining rate  
2 base.

3 Q. I refer you to Exhibit No. 8, Schedule 6, page 1, and ask you to explain  
4 the amount shown for liberalized depreciation.

5 A. Exhibit No. 8, Schedule 6, page 1 presents the Accumulated Deferred  
6 Income Tax Balance applicable to the use of liberalized depreciation for  
7 tax purposes. The per books balance at January 31, 2006, of  
8 \$39,925,410 is deducted in determining rate base.

9 Q. Does this conclude your testimony?

10 A. Yes.

National Fuel Gas Distribution Corporation  
Direct Testimony of John J. Spanos

1 Q. Please state your name and address.

2 A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill,  
3 Pennsylvania.

4 Q. Have you also presented testimony in these proceedings in a statement  
5 identified as Statement No. 104?

6 A. Yes, I have.

7 Q. What is the purpose of your testimony in Statement No. 4?

8 A. My testimony concerns the calculated annual depreciation for gas plant as  
9 of January 31, 2006.

10 Q. Have you prepared exhibits presenting the results of your depreciation  
11 study?

12 A. Yes. Exhibit No. 9, titled "Depreciation Study – Calculated Annual  
13 Depreciation Accruals Related to Gas Plant at January 31, 2006," presents  
14 the results of my depreciation study.

15 The results of my study, as they relate to the original cost of gas plant  
16 at January 31, 2006, are summarized on Exhibit No. 9 Schedule 1 Pages 3 -  
17 5 (also found in Exhibit No. 5):

18 Q. Please summarize the contents of Exhibit No. 9.

19 A. The contents of Exhibit No. 9 include summary tables and detailed  
20 tabulations of the results of the depreciation calculations related to gas plant  
21 in service at January 31, 2006. Table 1 (Exhibit No. 9 Schedule 1 Pages 3-  
22 5), presents a summary of the results of the depreciation calculations by  
23 depreciable group related to the original cost of Gas Plant in Service. The

National Fuel Gas Distribution Corporation  
Direct Testimony of John J. Spanos

1 table shows the estimated survivor curves, original cost, book reserve,  
2 future book accruals, composite remaining life and the calculated annual  
3 accrual rate and amount.

4 Table 2, on page 6 of Exhibit No. 9 Schedule, presents a summary of  
5 the cost of removal and salvage data for the five-year period 2001-2005.

6 Q. Were the methods and procedures used in the depreciation calculations at  
7 January 31, 2006, the same as those used in the depreciation calculations at  
8 January 31, 2007?

9 A. Yes, they were.

10 Q. Were the estimated survivor curves used in the depreciation calculations at  
11 January 31, 2006, the same as those used in the depreciation calculations  
12 at January 31, 2007?

13 A. Yes, they were.

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 Q. Please state your name and business address.

2 A. My name is Regina Truitt. My business address is 6363 Main Street,  
3 Williamsville, New York 14221.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by National Fuel Gas Distribution Corporation  
6 ("Distribution") as a Senior Manager in the Rates and Regulatory Affairs  
7 Department.

8 Q. What is your educational background and experience?

9 A. I graduated from State University of New York at Buffalo in 1979 with a  
10 Bachelor of Science Degree in Accounting. In 1979, I was employed by  
11 the New York State Department of Public Service. My work there  
12 involved examinations in rate proceedings, financings, fuel adjustment  
13 clause audits and in general accounting matters. I advanced to a Public  
14 Utilities Auditor II while employed at the Public Service Commission.

15 In 1985 I left the Public Service Commission and was employed  
16 by Metropolitan Transit Authority of Harris County in Houston, Texas. In  
17 September 1986, I was employed by Distribution.

18 Q. Have you previously testified before the Pennsylvania Public Utility  
19 Commission?

20 A. Yes, I have.

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National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 Q. Have you submitted expert testimony to any other regulatory  
2 commissions?

3 A. Yes. I have submitted testimony to the New York Public Service  
4 Commission.

5 Q. What is the purpose of your testimony?

6 A. My testimony covers three areas, revenues, cash working capital  
7 ("CWC") and the cost of service study ("COSS"). The revenue  
8 calculation of the per book revenues for the twelve months ended  
9 January 31, 2006 is presented in Exhibit No. 3. The CWC study  
10 calculations are presented in Exhibit No. 8-D. I also performed the Cost  
11 of Service Study, which was used by Mr. Clark in the proposed rate  
12 design.

13 Q. Please describe Exhibit No. 3.

14 A. Page 1 of Exhibit No. 3 is the summary page of the revenues for the  
15 twelve months ended January 31, 2006. Column 1 presents the  
16 revenues actually recorded ("per books") during the twelve months  
17 ended January 31, 2006 on the books of Distribution.

18 The second column presents the ratemaking adjustments to those  
19 per book revenues. The ratemaking adjustment consists of normalizing

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 the historic rate year volumes for weather and then pricing those  
2 volumes at rates in effect at February 1, 2006.

3 The third column represents the total of Columns 1 and 2.

4 The fourth column represents the adjustment to price the  
5 normalized historic volumes at the proposed rates and the fifth column is  
6 the normalized historic volumes priced at the proposed rates.

7 Pages 2 through 6 contain the responses to the filing  
8 requirements in the Commission's regulations pertaining to revenues in  
9 the historic year.

10 Q. Please describe Schedule 1 of Exhibit No. 3.

11 A. Schedule 1 is the proof of revenue for the historic year. The schedule  
12 takes the volumes billed during the historic year and prices them at the  
13 rates in effect during the historic year. There were several rate changes  
14 during the historic year. The historic year started with the rates that  
15 became effective February 1, 2005. These rates reflected the change in  
16 the customer education charge (Rider E) filed in Supplement No. 49 to  
17 P.U.C. No. 9 and was in effect until January 1, 2006.

18 On April 15, 2005, Supplement No.52 to PUC No. 9 became  
19 effective. The supplement reflected the Commission's order in R-

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 00049656, the Company's base rate proceeding. These rates are  
2 currently in effect.

3 Supplement No. 53 to PUC No. 9 changed Rider A and other  
4 associated rates and became effective on May 1, 2005. These Section  
5 1307(f) rates for the recovery of purchased gas costs were effective until  
6 August 1, 2005.

7 On August 1, 2005 Supplement No. 55 implemented the  
8 Commission's order in Case R-00050216, the Company's 1307(f) filing.  
9 Supplement No. 55 was in effect until November 1, 2005.

10 Supplement No. 56 implemented the quarterly gas cost change  
11 incorporated in Rider A and other associated rates and went into effect  
12 on November 1, 2005.

13 Supplement No. 57 implemented the change to the customer  
14 education charge on Rider E, effective January 1, 2006.

15 Q. Please describe Exhibit No. 3, Schedule 2.

16 A. Schedule 2 calculates the revenue for each rate schedule resulting from  
17 normalizing the volumes for temperature, which was spread among the  
18 rate blocks of the applicable rate schedule based upon the bill frequency  
19 for the twelve months ended January 31, 2006.

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1           The schedule also calculates the revenues using the normalized  
2 volumes and the proposed rates.

3    Q.    Please describe Exhibit No. 3, Schedule 3.

4    Q.    Exhibit No. 3, Schedule 3 calculates the late payment factor, which is  
5 applied to the normalized volumes priced at current rates and at  
6 proposed rates. The factor is calculated by dividing the total per book  
7 late payments by the applicable revenue booked during the historic year.

8    Q.    Please refer to Exhibit No. 8 Schedule 4 and explain the ratemaking  
9 principles governing the inclusion of cash working capital as an element  
10 of rate base in this proceeding.

11   A.    A proper amount of cash working capital must be included as an element  
12 of rate base in order to compensate investors for funds provided by  
13 investors, in addition to funds provided to finance utility plant investment,  
14 that are required by the utility to operate as a going concern. The  
15 amount of cash working capital must be sufficient to cover the lag  
16 between payment of expenses by a utility and the receipt of cash from  
17 the utility's customers in payment for services furnished. Cash working  
18 capital provides only for current or day-to-day cash needs of the  
19 business and not for any of the capital requirements related to financing  
20 facilities.

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 Q. Is there a difference in the ratemaking and accounting concepts of  
2 working capital?

3 A. Yes. The ratemaking concept of cash working capital must be  
4 distinguished from the accounting concept. Accountants that are not  
5 involved in utility ratemaking, define working capital as the difference  
6 between current assets and current liabilities, which is a measure of a  
7 business's liquidity at a point in time.

8 The ratemaking concept, in contrast, defines cash working capital  
9 as the amount of capital that a utility requires, over and above  
10 investment in utility plant and other rate base items, to cover the gap  
11 between the receipt of cash by a utility from its customers as payment  
12 for service and the payment of cash by a utility to its vendors,  
13 employees, taxing agencies, etc.

14 Q. What is the cash working capital requirement for the historic test year in  
15 the proceeding?

16 A. As set forth in Exhibit Nos. 8 and 108, the cash working capital  
17 requirement, for the twelve months ended January 31, 2006, is  
18 \$41,126,000, for the twelve months ended January 31, 2007, is  
19 \$40,372,000.

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 Q. What method of determining the cash working capital allowance have  
2 you employed in this rate proceeding?

3 A. I have performed a lead/lag study to determine the cash working capital  
4 requirement in this proceeding. This methodology compares the  
5 difference in time between (1) Distribution's furnishing service and  
6 Distribution's receipt of revenues for service (the "revenue lag") and (2)  
7 incurrence of expenses by the Company and the payment for those  
8 expenses (the "expense lag"). The "net lag" (difference between  
9 revenue lag and expense lag) is then multiplied by the average daily  
10 cash balance necessary to cover Distribution's expenses. In essence,  
11 this method determines the dollar amount of cash working capital that  
12 must be included in rate base in order to provide investors with a return  
13 on funds provided to permit Distribution to meet day-to-day operating  
14 expenses.

15 Q. Describe how the revenue lag was determined.

16 A. Revenue lag is the average amount of time that Distribution has  
17 extended credit for the service rendered to its sales service and  
18 transportation customers. It is the time period or "lag" between  
19 furnishing of service and receipt of payment from the customer for such  
20 service. In the determination of the revenue lag, the first component

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 determined was the service lag, which is the time period from the mid-  
2 point of the period during which service is furnished to the date the meter  
3 is read. Second, the billing lag is calculated, which reflects the lag  
4 between the meter reading dates and billing dates, i.e., the date bills are  
5 mailed to customers. For meter reading and billing purposes, customers  
6 are divided into 21 groups or "controls". A bill to each member of one of  
7 these groups is sent on the same day. Bills are mailed to different  
8 groups on different days once each month. Both the service lag and the  
9 billing lag, for the test period ended January 31, 2006, are calculated by  
10 accumulating the actual service and billing lags for all "controls" in each  
11 month of the year and dividing these two totals for service and billing  
12 lags by the number of "controls" included in the test period. The third  
13 component that is included in the revenue lag is called the collection lag,  
14 which represents the time from the day the bill was mailed to the  
15 customer to the day of the payment.

16 The collection lag was developed for the twelve months ended  
17 January 31, 2006, by starting with the accounts receivable balance at the  
18 beginning of each month, adding the total daily customer billings and  
19 deducting the total daily customer payments on each day to develop a  
20 daily accounts receivable balance outstanding for each day within the

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 month. The daily accounts receivable balances and daily billed revenue  
2 amounts are then accumulated by month for the entire test period.

3 Dividing the total of billed revenue into the sum of the daily accounts  
4 receivable balances for the study period produces the average amount  
5 of time between the billing date and the date of payment for services.

6 The average lag in days for the receipt of revenue is the combined total  
7 of the three categories discussed above. The revenue lag for the  
8 historic test period, twelve months ended January 31, 2006, is 72.45  
9 days. Details can be found on Exhibit No. 8, Schedule 4, Page 5.

10 Q. Explain the lag day calculation for the purchase gas expense.

11 A. An examination was made of all major gas invoices for the test year  
12 ended January 31, 2006. In order to compute the number of lead and/or  
13 lag days, the service period to which each billing is applicable is first  
14 determined (January, February, etc.). Then the mid-point of service with  
15 regard to each gas billing is calculated by taking the number of service  
16 days in the month and dividing by two. Finally, the time from the mid-  
17 point of the service period to the payment date was computed in order to  
18 produce the number of lead or lag days for each month. To present  
19 properly the yearly average, the monthly lag days were multiplied by the  
20 applicable monthly expense dollars to determine the monthly weighted

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 average dollar days. The total purchased gas expense was then divided  
2 into the sum total of the monthly weighted average dollar days to  
3 produce a result of 40.20 days of lag (Exhibit No. 8, Schedule 4, Page  
4 5).

5 Q. Describe in general the expense lags and how they were determined.

6 A. Expense lags arise when Distribution receives credit for the various  
7 costs of rendering service, which have been advanced to Distribution by  
8 its suppliers, employees, and taxing agencies. It represents the length  
9 of time between the receipt of such commodities or services and the  
10 payment for them by Distribution. Expenses used to develop the  
11 expense lag days are separated into their basic components, such as  
12 purchased gas, labor, goods and services and various taxes. The  
13 service periods to which the expenses relate and dates of payment of  
14 the expenses were ascertained by reviewing Distribution's records for  
15 the test period ended January 31, 2006. The total expense lag is  
16 determined by multiplying the total expense in each category of expense  
17 by the respective number of lead or lag days associated with it. The  
18 sum of these products equals the total dollar day lag for expenses.  
19 Dividing this by the total expenses produces the net weighted average  
20 days of lag for the cost of services rendered and advanced to

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 Distribution by its suppliers, employees and taxing agencies. This  
2 procedure produced the total expense lag, including taxes, of 34.68 days  
3 for the twelve months ended January 31, 2006, and 34.40 days for the  
4 twelve months ended January 31, 2007. The derivations of these figures  
5 are shown on Schedule 4, Page 6 on Distribution's Exhibit No. 8 and  
6 108, respectively.

7 Q. How was the cash working capital requirement computed?

8 A. The cash working capital requirement was computed by first taking the  
9 difference between the average revenue lag and the average expense  
10 lag, which is called "net lag". The "net lag" is 37.77 days for the twelve  
11 months ended January 31, 2006, and 38.05 days for the rate year twelve  
12 months ended January 31, 2007. This "net lag" was then multiplied by  
13 the average daily expense amounts for the historic and future test year  
14 to provide the required cash working capital allowance. This  
15 computation is demonstrated for the historic and future test years on  
16 Schedule 4, Page 7 of Exhibit No. 8 and Exhibit No. 108, respectively.

17 Q. Explain the remaining specific expense and tax items included in the  
18 study and how the days of lead or lag were computed with regard to  
19 these items.

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 A. Payroll lag is calculated by computing the time from the mid-point of the  
2 pay period to the date of payments to employees. The total payroll of  
3 Distribution's Pennsylvania Division for the twelve months ended  
4 January 31, 2006 was reviewed and the payment dates were determined  
5 from cash vouchers. The resulting expense lags are 14.00 days for  
6 weekly payroll and 6.82 days for supervisory payroll. The applicable lags  
7 for the Federal, State and FICA withholding taxes are also calculated in  
8 the same manner.

9 Q. Briefly explain the calculation of expense lags for the remaining expense  
10 items.

11 A. The remaining expense items are employee benefits and other goods  
12 and services. The lags relating to these categories of expenses were  
13 determined in the same manner as the lags associated with payroll  
14 expenses. The service period for each expense was determined from  
15 the Company's records and then the mid-point of service was calculated  
16 by dividing the service period by two. The mid-point of the service period  
17 is then related to the date the expense was paid. By calculating the time  
18 from the mid-point of service period to the date paid, the appropriate  
19 lead and/or lag days were produced. To properly calculate the average  
20 lag, the lead and/or lag days were multiplied by the applicable expense

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 dollars to determine the weighted average dollar days. The sum total of  
2 the expense was then divided into the sum total of the weighted average  
3 dollar days to determine the applicable weighted average lag days. For  
4 other goods and services, 3,592 invoices paid during the test period  
5 were examined to determine an average that would be representative of  
6 the entire year. The first step in creating this appropriate sample was to  
7 conduct a query of Distribution's accounts payable transactions on a  
8 monthly basis. Then, each month was analyzed in isolation, and all  
9 transactions less than \$1,000, or greater than \$200,000 were excluded.  
10 Next, each was assessed to ensure that the goods or service was not  
11 accounted for in another lag analysis. If the expense was already  
12 recognized, it was excluded along with any other prepayment items such  
13 as PaPUC assessment, AGA dues, prepaid insurance, etc. In  
14 compliance with the Commission's ruling in Case No. R-850287, the  
15 Uncollectible expense was also excluded from consideration. At this  
16 point, the appropriate service period was determined from dates within  
17 Distribution's accounting system. A mid-point of service was  
18 determined. The payment date was then taken from the accounting  
19 system to develop an actual lead or lag for each transaction. For each  
20 transaction, the expense amount was then multiplied by the lead/lag to

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 create a weighted cost. The expense and weighted cost were  
2 accumulated for all transactions within a given month, and compiled for  
3 the historic twelve months ended January 31, 2006 to create a  
4 cumulative average lag of 10.58 days (Exhibit No. 8, Schedule 4, Page  
5 5)

6 Q. On Exhibit No. 8, Schedule 4, Page 5 you reflect a cost of service of  
7 \$8,185,000 for Post Retirement Benefits Other Than Pensions (OPEBs).  
8 What payment pattern for funding have you used for this item?

9 A. Distribution has elected to fund OPEBs on a quarterly basis, with the  
10 assumption that the monthly benefit payments will equal the quarterly  
11 funding amounts. The funding dates from the historic period were used  
12 to determine a 30.72 lag day result.

13 Q. What payment pattern for Pension funding have you estimated for this  
14 item?

15 A. Pension is currently funded on an annual basis. The exception to this is  
16 the amortization of the previous funding over and above the rate  
17 allowance that was allowed to be deferred and amortized by the  
18 Commission in its order for Distribution's rate case R-00038168. The  
19 funding dates of October 10, 2002 and February 28, 2003 were used to  
20 compare to the service period of the current historic rate year month.

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1           The amortization therefore has significant lead days (funding occurred  
2           before the service period) which offset the current annual funding and  
3           calculates to a Pension lead of 131.9 days.

4    Q.    Is the concept of determining lead and/or lag days for taxes other than  
5           income taxes the same as for other expenses?

6    A.    Yes. As for all other expense items, service periods, mid-point dates  
7           and paid dates are identified and employed in the determination of lead  
8           and/or lag days for taxes other than income taxes.

9    Q.    Is this also true of the calculation of the lags for the Capital Stock Tax  
10           and the Public Utility Realty Tax (PURTA)?

11   A.    No. With both taxes, the payment of the tax requires that a tentative  
12           payment is made before the actual tax is calculated and a final payment  
13           is paid. The Capital stock Tax has four quarterly payments based on the  
14           previous tax return with a final payment paid with the tax return. From  
15           1995-2005 Distribution paid an average of 90.76% of the actual tax in  
16           those quarterly payments and 9.24% with the final payment. After  
17           weighting the payment s with those averages the lag days for Capital  
18           Stock is calculated to be 53.49 days.

19                    PURTA has the same requirement except that only one tentative  
20           payment is made. From 1995 to 2005 the average is 81.41% for the

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 tentative payment and 18.59% for the final payment. Applying the  
2 averages to the payments made in the historic rate year the lead days  
3 are calculated to be 36.53 days.

4 Q. How have income taxes been reflected?

5 A. The same methodology used for Capital Stock and PURTA has been  
6 applied to the Income Taxes. Estimated payments are made during the  
7 year and a final payment is made with the filing of the tax return. The  
8 calculation of the average payments and the final payment leads to a lag  
9 calculation of 37.25 days for the Federal Income Taxes and 55.45 days  
10 for the Pennsylvania State Income Tax.

11 Q. Please explain the adjustments to cash working capital shown on Page 2  
12 of Exhibit 8, Schedule 4.

13 A. The lead/lag study results have been adjusted by an amount designed to  
14 reflect a theoretical lag in the payments by Distribution for interest on  
15 long-term debt and in the payment for short-term debt interest.

16 Q. How does the payment lag differ for long and short-term debt?

17 A. The lag in payment of long-term debt is 86.16 days, based on an  
18 analysis of the long-term debt outstanding as of January 31, 2006.  
19 Notes 93-2, 95-1 and 03-1 require semi-annual payments and Note 02-2  
20 requires quarterly payments. Each mid-point for each note was

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

1 multiplied by the associated long-term debt to obtain a weighted average  
2 total, and divided by the long-term debt outstanding to determine the net  
3 lag. When this lag is compared to the revenue lag, a net lag is  
4 computed of 13.71 is calculated. This creates an additional need of  
5 CWC in the amount of \$282,000 in the historic year and \$297,000 in the  
6 *future test period*.

7 For short-term debt, cash management provided a daily analysis  
8 of the Company's short-term debt for the twelve months ending January  
9 31, 2006. On a monthly basis, average days to an interest payment and  
10 the average dollar amount outstanding were determined. These 2 items  
11 were multiplied to obtain a weighted dollar amount for each month. The  
12 sum of the 12 weighted averages was divided by the sum of the 12  
13 monthly average outstanding amounts to obtain the service period of  
14 7.12 days. This was divided by 2 to determine the mid-point of short-  
15 term interest payments of a lag of 3.56 days lag. When compared to the  
16 revenue lag, a net lead is computed which reduces the amount of CWC  
17 necessary by \$197,000 in the historic year and \$286,000 in the future  
18 test period.

19 Q. Please address Exhibit No. 11.

National Fuel Gas Distribution Corporation  
Direct Testimony of Regina Truitt

- 1 A. Exhibit No. 11 addresses the Commission's filing requirements regarding  
2 rate design and the Cost of Service Study. The Cost of Service and rate  
3 design supporting the revenue requirement is found in Exhibit No. 111  
4 and will be discussed in Statement No. 105.
- 5 Q. Does this complete your testimony?
- 6 A. Yes, it does.

National Fuel Gas Distribution Corporation  
Direct Testimony of Joanne E. Zablonki

1 Q. Please state your name and business address.

2 A. My name is Joanne E. Zablonki. My business address is 6363 Main Street  
3 Williamsville, New York 14221.

4 Q. By whom and in what capacity are you employed?

5 A. I am employed by National Fuel Gas Distribution Corporation ("Distribution"  
6 or the "Company") as Senior Manager in the Rates and Regulatory Affairs  
7 Department.

8 Q. State briefly your educational and professional experience.

9 A. I graduated from Erie Community College, Buffalo, New York in May,  
10 1981, with an Associate of Applied Science Degree in Data Processing.  
11 In May, 1989, I received a Bachelor of Science Degree in Management  
12 from State University of New York at Buffalo.

13 In September, 1981, I began my employment in the Research and  
14 Statistical Services Department as a Research Assistant. In July, 1987, I  
15 was elevated to Analyst and subsequently promoted to Senior Analyst,  
16 Consultant, Assistant Manager and Director in the Market Planning  
17 Department. In March, 2001 I was transferred to the Gas Supply  
18 Administration Department where I assumed certain gas procurement  
19 responsibilities. I was elevated to Manager of Gas Procurement in  
20 August, 2001. In October, 2004, I transferred to the Rates and Regulatory  
21 Affairs Department as Senior Manager, my current position. As Senior  
22 Manager of Rates and Regulatory Affairs, my duties include gas load

National Fuel Gas Distribution Corporation  
Direct Testimony of Joanne E. Zablonski

1 forecasting, competitive analysis, market research and gas and electric  
2 deregulation related activities.

3 Q. Have you previously testified before the Pennsylvania Public Utility  
4 Commission ("Commission")?

5 A. Yes. I have testified before this Commission on behalf of Distribution in  
6 its Purchased Gas Costs - 66 Pa. C.S. Section 1307(f) in Docket Nos. R-  
7 901573, R-901862, R-912101, R-922499, R-932885, R-943207, R-  
8 953487, R-963779, R-974167, R-984497, R-994898, R-00050216 and R-  
9 00061246. I have also testified before this Commission on behalf of  
10 Distribution in its base rate proceedings Docketed at R-932548, R-942991  
11 and R-953299.

12 Q. Have you presented expert testimony before any other regulatory  
13 commissions?

14 A. Yes. In addition to the expert testimony I have presented to this  
15 Commission, I have presented testimony before the New York Public  
16 Service Commission in Docket Nos. 89-G-179, 90-G-0734, 91-G-0846,  
17 93-G-0756, 94-G-0885 and 95-G-1009.

18 Q. What is the subject of your testimony?

19 A. I will explain the determination of sales and transportation volumes for rate  
20 making purposes, including the weather normalization and load growth  
21 adjustments, along with other explanatory exhibits regarding sales volumes  
22 and weather.

National Fuel Gas Distribution Corporation  
Direct Testimony of Joanne E. Zablonki

1 Q. Please explain Exhibit No. 10, Schedule 1.

2 A. Exhibit No. 10, Schedule 1, consisting of three pages, provides monthly  
3 sales for residential and commercial heating customers for the 48 months  
4 ended January 31, 2006. The sales volumes shown on page 2 are actual  
5 sales volumes; the volumes have not been adjusted for the effects of  
6 weather. The degree day information for each year is provided on page 3.  
7 Page 3 shows the calendar month degree days by month for the 48 months  
8 ended January 31, 2006 and billing month degree days (average of the 21  
9 cycles) by month for the 48 months ended January 31, 2006.

10 Q. Explain the information on Exhibit No. 10, Schedule 2.

11 A. This exhibit shows the actual growth patterns of throughput sales volumes  
12 and number of customers from January 31, 2003 by year through the end  
13 of the historic test year, and as forecasted by year through January 31,  
14 2009. The index for these ratios is January 31, 2003. It should be noted  
15 that the historical volumes used to produce the index shown from January  
16 31, 2003 to January 31, 2006 are actual volumes and are not normalized  
17 for weather, whereas the indices for the forecasted years January 31, 2007  
18 to January 31, 2009 are based on projected sales volumes at normal  
19 weather.

20 Q. Explain Exhibit No. 10, Schedule 3.

21 A. This exhibit contains copies of the tariff pages which set forth Distribution's  
22 Gas Emergency Plan. In this proceeding, no adjustments for curtailments

National Fuel Gas Distribution Corporation  
Direct Testimony of Joanne E. Zablonki

1 have been made because we do not anticipate any curtailments during the  
2 forecast period.

3 Q. Explain Exhibit 10, Schedule 4.

4 A. This exhibit shows the Company's policy with respect to replacing  
5 customers lost through attrition, and procedures developed to govern  
6 relationships between the respondent and potential customers.

7 Q. What does Exhibit No. 10, Schedule 5 show?

8 A. Exhibit No. 10, Schedule 5 is a 5 page document providing data for the Test  
9 Year and the four previous years on peak day demand, monthly  
10 consumption and average daily consumption. Page 2 lists the maximum  
11 coincident peak day demand and the maximum coincident three-day peak  
12 day demand for the most recent winter period for which measured peak day  
13 volumes are available (2005-2006 winter) and the previous four winter  
14 periods. Customer class peak day was allocated to the residential,  
15 commercial, public authority and industrial categories based upon an  
16 estimate of each class's contribution to peak month. Industrial peak day  
17 volumes for daily metered transportation (DMT) customers are based on  
18 actual daily consumption.

19 Page 3 of the exhibit lists average monthly throughput consumption  
20 by class during the primary heating season (November-March) for 2000-  
21 2001 through 2005-2006. Page 4 shows the average monthly consumption  
22 by class for the non-heating season (April-October) for the same years.

National Fuel Gas Distribution Corporation  
Direct Testimony of Joanne E. Zablonki

1 Page 5 of the exhibit shows the average daily throughput consumption by  
2 class for these years. This exhibit shows actual (not weather normalized)  
3 data.

4 Q. Explain Exhibit No. 10, Schedule 6.

5 A. This exhibit shows the projected sales and transportation volumes for the  
6 twelve months ending January 31, 2007, 2008 and 2009 by customer class.  
7 The forecasts are based on normal temperatures.

8 Q. Explain Exhibit No. 10, Schedule 7.

9 A. This exhibit shows a reconciliation of test year sales and line losses, and  
10 gas requirements and supplies for the 24 month period ended January 31,  
11 2006.

12 Q. Explain Exhibit 10, Schedule 8.

13 A. Exhibit No. 10, Schedule 8 summarizes the weather normalization  
14 calculation. Page 1 details the weather adjustment methodology. In  
15 summary, Distribution's customers are billed throughout the month on a 21-  
16 cycle basis. The weather normalization adjustment shown on pages 2  
17 through 4 is the summary of the weather normalization process of  
18 calculating for the effects of temperatures for each of the 21 cycles. Normal  
19 degree day values are based on the period 1971 – 2000, as published by  
20 the National Oceanic and Atmospheric Administration (NOAA) for the first-  
21 order National Weather Office located at the Erie, Pennsylvania  
22 International Airport. Actual degree day values are based on the NOAA

National Fuel Gas Distribution Corporation  
Direct Testimony of Joanne E. Zablonki

1 observations at the Erie, Pennsylvania International Airport. Page 5  
2 contains the average (of the 21 cycles) actual billing degree days for the  
3 twelve months ended January 2006 and the average (of the 21 cycles)  
4 normal level of degree days. Degree days, as used here, are the amount  
5 by which 65 degrees F exceeds the average of the high and low  
6 temperatures for any day. If the average temperature is below 65 degrees  
7 F, a customer is assumed to utilize his heating equipment.

8 Normalization adjustments are made only with regard to the  
9 residential, commercial and public authority customer classes because only  
10 these classes have significant temperature-sensitive, space-heating loads.  
11 The adjustment to actual sales volumes to reflect normal temperatures is  
12 accomplished in the following steps. The monthly base volume per account  
13 is that portion of the total load which does not change with changes in  
14 temperature and is not heating-sensitive. For the twelve months ended  
15 January 2006, the representative monthly base volume calculation was  
16 based on the three lowest consecutive months of July, August and  
17 September. The monthly base volume per account is then subtracted from  
18 the actual monthly consumption per account to determine the actual heating  
19 load per account.

20 Next, heating consumption per degree day is determined by dividing  
21 the actual gas heating load consumption by the actual monthly billing  
22 degree days experienced. The normalized heating usage per account is

National Fuel Gas Distribution Corporation  
Direct Testimony of Joanne E. Zablonksi

1 derived by multiplying the heating use per degree day by the normal  
2 monthly degree days associated with each particular control. The monthly  
3 base volume per account is then added to the monthly normalized monthly  
4 usage per account. The normalized monthly consumption is derived by  
5 multiplying the normal usage per account by the monthly number of  
6 accounts.

7 This procedure is performed for each of the 21 cycles by revenue  
8 class. The sum of the actual Mcf, accounts and normalized Mcf for the 21  
9 cycles is shown on pages 2 through 4 as monthly figures.

10 Q. Explain Exhibit No. 10, Schedule 9.

11 A. Exhibit No. 10, Schedule 9 adjusts volumes for the historic test year, the  
12 twelve months ended January 31, 2006, for changes in the projected  
13 numbers of customers. The methodology employed and the volumetric  
14 adjustment by class is explained on Exhibit No. 10, Schedule 9.

15 Q. Does this conclude your testimony?

16 A. Yes, at this time.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF GARTH D. ANDERSON

1 Q. Please state your name and business address.

2 A. My name is Garth D. Anderson. My business address is 6363 Main  
3 Street, Williamsville, New York 14221.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by National Fuel Gas Distribution Corporation  
6 ("Distribution") as a Senior Accountant.

7 Q. What is your educational background and experience.

8 A. I graduated from the State University of New York at Buffalo in 1992  
9 with a Bachelor of Arts degree in Psychology. In 1997, I graduated  
10 from the State University of New York at Buffalo with a Master of  
11 Business Administration Degree concentrating in Accounting. In  
12 October 1997, I was hired by Ernst & Young, LLP as a Staff Auditor  
13 into their Assurance Advisory Business Services Department. In  
14 September 1999, I was registered with the State of New York as a  
15 Certified Public Accountant, license #082429. In October 1999, I was  
16 hired by M&T Bank as an Audit Supervisor into their Internal Audit  
17 Department. In June 2000, I was hired by Distribution as a General  
18 Accountant I. In January 2004, I was promoted to General Accountant  
19 II. In February 2006, I was promoted to my current position, Senior  
20 Accountant.

21 Q. What are your duties as a Senior Accountant?

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NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF GARTH D. ANDERSON

1 A. Under the general direction of the Senior Manager of Accounting, I am  
2 responsible for the review of monthly journal entries for revenues and  
3 purchased gas expenses for Distribution. I am also responsible for the  
4 review of periodic regulatory reports to the New York State Public  
5 Service Commission and the Pennsylvania Public Utility Commission.  
6 In addition, I perform various functions related to the accounting  
7 consolidation of National Fuel Gas Company and subsidiaries. This  
8 includes internal analyses and external reporting requirements in  
9 accordance with generally accepted accounting principles and  
10 Securities and Exchange Commission requirements.

11 Q. Have you previously testified before the Pennsylvania Public Utility  
12 Commission?

13 A. Yes, I have testified before this Commission on behalf of Distribution in  
14 Docket numbers R-00038168 and R-00049656.

15 Q. Are Distribution's accounts maintained in accordance with the Uniform  
16 System of Accounts?

17 A. Yes.

18 Q. State the exhibits you are sponsoring.

19 A. Exhibit Nos. 1 (schedules 1-19), 2 (schedules 4-8), 4 (schedules 11-  
20 19), 13 (schedules 5 and 6), 101 and 104 (schedule 9).

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF GARTH D. ANDERSON

1 Q. Do these exhibits contain information taken from the books of  
2 Distribution?

3 A. Yes.

4 Q. Would additional explanation be helpful concerning any of these  
5 exhibits?

6 A. Yes. Each exhibit sets forth the Commission's applicable filing  
7 requirement, at 52 Pa. Code Sections 53.51, et seq. Distribution's  
8 response is for the most part self-explanatory although additional  
9 explanation may be helpful concerning certain exhibits. Exhibit No. 1;  
10 schedule 1 provides the balance sheets for Distribution at January 31,  
11 2006 and January 31, 2005.  
12 Schedule Nos. 2 through 18 provide details on individual balance sheet  
13 items. Explanations of the origin and purpose of certain balance  
14 sheets accounts are included. Concerning the balance sheet exhibits  
15 identified previously, it should be noted that Distribution provides  
16 service in New York and Pennsylvania. Distribution, however, does  
17 not compile balance sheets separately for either Pennsylvania Division  
18 or New York Division operations. As a result, the balance sheet can  
19 be provided only for Distribution in its entirety.

20 Q. Please refer to Exhibit 2, schedule 5, and explain it.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF GARTH D. ANDERSON

1 A. Exhibit No. 2, schedule 5 provides comparative operating statements  
2 per books, for the Pennsylvania Division for the twelve months ended  
3 January 31, 2006 and January 31, 2005, showing increases and  
4 decreases between the two periods. Pages 4-6 of Exhibit No. 2,  
5 schedule 5, contain explanations of the causes of major variances  
6 between the twelve months ended January 31, 2006 and the preceding  
7 year, by detailed account number.

8 Q. Please explain Exhibit No. 2, schedule 6.

9 A. Exhibit No. 2, schedule 6, provides an income statement for  
10 Distribution by division for the twelve months ended January 31, 2006.

11 Q. Please explain Exhibit No. 4, schedule 19.

12 A. Exhibit No. 4, schedule 19, consists of eight pages showing the  
13 Pennsylvania Division's Operating and Maintenance Expenses per  
14 books for the twelve-month periods ended January 31, 2004, January  
15 31, 2005 and January 31, 2006. The expenses are listed by detail  
16 accounts and are summarized by functional classification.

17 Q. Please explain Exhibit No. 4, schedule 11.

18 A. Exhibit No. 4, schedule 11, contains a copy of the contract that  
19 describes the nature of services rendered by affiliated companies  
20 where the charges for these services are included in the operating

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF GARTH D. ANDERSON

1 expenses of the Pennsylvania Division of Distribution for the test year  
2 and for the twelve month period ended prior to the test year. Pages  
3 13 – 16 of this exhibit summarize the charges for services rendered by  
4 functional account for the twelve months ended January 31, 2005 and  
5 January 31, 2006 based on the actual cost of such services. The  
6 determination of cost is outlined in Article IV of the Service Agreement,  
7 pages 9 and 10 of schedule 11. Utilizing the services of, for example,  
8 National Fuel Gas Supply Corporation ("Supply"), eliminates  
9 duplication of personnel and related facilities that otherwise would  
10 result if Distribution undertook to perform certain services itself. By  
11 utilizing the services of Supply on an as-needed basis, economies are  
12 achieved that are passed along to customers through a lower cost of  
13 service for Distribution.

14 Q. Describe the services provided by Supply.

15 A. Supply provides primarily field services in the nature of operation and  
16 maintenance of field facilities and mains. Economies are achieved by  
17 Distribution's use of Supply's personnel instead of employees of  
18 Distribution because there are instances in which Supply's personnel  
19 and equipment are either close to the field area where the services  
20 must be provided or have the necessary specialized experience and  
21 equipment to perform the tasks required. In this regard, it is to be

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF GARTH D. ANDERSON

1 noted that Supply's transmission lines pass through and overlay  
2 Distribution's entire distribution system. This can be seen by referring  
3 to Exhibit No. 15, sch. 2, page 2 that shows, under the designation  
4 "National Fuel Gas System Map", Supply's major lines. Since Supply  
5 must have employees and equipment to maintain these transmission  
6 lines throughout Distribution's service areas, there are instances where  
7 it is less expensive for Supply's personnel to operate and maintain  
8 Distribution's field facilities than it would be for employees of  
9 Distribution.

10 Q. Do Supply's personnel provide any other services to Distribution?

11 A. Yes. As shown on page 13 of Exhibit No. 4, schedule 11, some  
12 charges from Supply are recorded by Distribution to customer  
13 accounts, customer service and gas control and gas measurement  
14 services. Some of Distribution's large customers have orifice or chart  
15 meters which are read by Supply personnel. Because such meters are  
16 used to measure gas transported by Supply to Distribution and other  
17 gas distribution companies, Supply must have the trained personnel  
18 and special equipment required to read these meters. Supply can read  
19 orifice or chart meters that are used by Distribution's customers at a  
20 cost which is less than costs that would be incurred for Distribution to  
21 hire, to train and thereafter to maintain its own personnel for such

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
DIRECT TESTIMONY OF GARTH D. ANDERSON

1 purposes and for Distribution to own and operate its own equipment in  
2 order to read orifice or chart meters. As a result, Supply's personnel  
3 read Distribution's orifice and chart meters for measurement of sales to  
4 customers and perform related customer service functions. Natural  
5 gas production attached directly to Distribution's system that is either  
6 purchased by Distribution from independent producers or transported  
7 by Distribution to end-use customers is also measured by orifice or  
8 chart meters. Supply's personnel also read these meters. Supply's  
9 charges for this service represent a portion of amounts booked by  
10 Distribution to the Gas Supply operating accounts as shown on page  
11 13 of Exhibit No. 4, schedule 11.

12 Q. Does this conclude your testimony?

13 A. Yes, it does.

**National Fuel Gas Distribution Corporation  
Direct Testimony Of David P. Bauer**

1 Q. Please state your name and business address.

2 A. My name is David P. Bauer, and my business address is 6363 Main  
3 Street, Williamsville New York, 14221-5887.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by National Fuel Gas Distribution Corporation  
6 ("Distribution" or "the Company") as Assistant Treasurer.

7 Q. Please state briefly your educational and professional experience.

8 A. I graduated from Boston College in 1991 with a Bachelor of  
9 Science degree, with highest honors, in Accounting. Shortly after  
10 graduation, I began my employment with the Buffalo Office of Price  
11 Waterhouse (currently PricewaterhouseCoopers). The last  
12 position I held with PricewaterhouseCoopers was Senior Audit  
13 Manager. In 2001, I joined Distribution as General Manager -  
14 Accounting. In April 2004 I was promoted to Assistant Treasurer of  
15 Distribution.

16 Q. Have you previously testified before this Pennsylvania Public  
17 Utilities Commission?

18 A. Yes, I testified before this Commission on behalf of Distribution in  
19 Docket Nos. R-0038168 and R-0049656.

20 Q. Have you testified before any other Commission?

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**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1 A. Yes, I have testified before the New York State Public Service  
2 Commission.

3 Q. What is the purpose of your testimony?

4 A. My testimony reviews the Company financial information provided  
5 to Mr. Hanley for preparation of his testimony concerning the fair  
6 rate of return. I am also responsible for the debt components used  
7 by Mr. Hanley and for the Company's claim regarding pension and  
8 post-retirement benefits costs. I am also responsible for a number  
9 of Exhibits that provide Company financial information in  
10 compliance with the filing requirements of the Pennsylvania Public  
11 Utility Commission ("Commission").

12 Q. What Exhibits in this proceeding are sponsored by you?

13 A. I am sponsoring the following Exhibits in this proceeding:  
14 Exhibit Nos. 401, 402, 403, 404, 405, 406, 407, 408, 409, 410, 411,  
15 412, 413, and Exhibit No. 414.

16 These Exhibits are provided in response to the Commission's filing  
17 requirements relating to finance and accounting activities and are  
18 self-explanatory.

19 I am also sponsoring Exhibit No. 4 Schedule 2 (Benefits) Pages 11  
20 and 12 and Exhibit No. 104 Schedule 2 (Benefits) Pages 13 and 14

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1           which relate to the Company's pension and post-retirement benefit  
2           claim.

3           Financial Information

4           Q.     Mr. Frank J. Hanley has presented direct testimony (Statement  
5           No. 10) concerning the fair rate of return in this proceeding. In  
6           preparation of that testimony Mr. Hanley relied to a certain degree  
7           on financial information provided to him by the Company. Was the  
8           financial information provided to him by the Company prepared by  
9           you or under your supervision?

10          A.     Yes, the Company information provided to Mr. Hanley for  
11          preparation of his testimony was prepared by me or prepared under  
12          my supervision.

13          Q.     Please explain how you calculate the debt costs associated with  
14          the debt ratio of 48.5% used for ratemaking purposes.

15          A.     Since substantially all of Distribution's "debt" is derived from  
16          National Fuel Gas Company ("National Fuel"), the Corporate parent  
17          of Distribution, it is appropriate to utilize National Fuel's actual and  
18          estimated costs of both long- and short-term debt at the end of the  
19          historical and future test years, namely January 31, 2006 and  
20          January 31, 2007.

21

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1    Long Term Debt

2    Q.    What cost rate for long-term debt is most appropriate for use in  
3           your cost of capital determination?

4           A. The actual at January 31, 2006 and estimated at January 31, 2007  
5           long-term debt cost rate is 6.64% as shown on pages 2 and 3 of  
6           Schedule 6, Exhibit No. 406. In arriving at the estimated cost rate  
7           of 6.64%, as summarized on page 3 of Schedule 6, I have reflected  
8           maturities and financing activity expected in National Fuel's fiscal  
9           2006 and 2007. Also, in developing the embedded cost rates to  
10          maturity by issue, I have taken into account the impact of the  
11          necessary costs of issuance. If such costs are not permitted to be  
12          recovered in the effective long-term debt cost rate, recovery would  
13          be at the expense of the common shareholder and the cost rate for  
14          common equity capital would then otherwise be higher. Notes  
15          relevant to pages 2 and 3 are shown on page 4 of Schedule 6. The  
16          calculation of the effective interest rate by long-term debt  
17          instrument is provided on page 10 of Schedule 6. The composite  
18          interest rate at January 31, 2006 and estimated January 31, 2007  
19          reflects the refinancing adjustments to both the balance of long-  
20          term debt and the annualized cost. Details of the base year  
21          refinancing adjustments can be found on pages 6 through 9 of

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1           Schedule 6. The base year refinancing adjustments, which affect  
2           the computation of the composite interest rate of debt and level of  
3           debt capital to be used in this proceeding, have been updated to  
4           reflect recovery of the after tax premium amortization through  
5           January 31, 2007. The summary of these updates can be found on  
6           page 5 of Schedule 6.

7           Q. Please describe the rationale for the base year refinancing  
8           adjustments.

9           A. The purpose of these refinancings was to reduce National Fuel's  
10          long-term debt cost rate. Because it is a significant input in the  
11          determination of Distribution's overall cost of capital, Distribution's  
12          customers receive a ratemaking benefit from the reduction in  
13          National Fuel's long-term debt cost rate. Therefore, it is only fair  
14          that, in exchange for receiving the benefit of the reduction in capital  
15          costs, Distribution's customers bear the additional costs related to  
16          the refinancing. This results in three adjustments in the Calculation  
17          of Composite Interest Rate of Total Debt set forth in Exhibit 406,  
18          Schedule 1, pages 1 and 2. First, the unamortized balance of the  
19          after-tax premiums and issuance expenses incurred in connection  
20          with the refinancings are excluded when determining the debt ratio  
21          for ratemaking purposes. To do otherwise would result in a debt

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1 ratio that is higher than would have been had there been no call or  
2 tender premiums and related costs of the refinancings. If the debt  
3 ratio were not reduced, customers would improperly benefit twice:  
4 once through a reduction of the debt cost for ratemaking purposes  
5 and once through the increase in the debt ratio (with a concomitant  
6 reduction of equity ratio). Second, the after-tax cost of the  
7 refinancing premiums are amortized and recovered via the long-  
8 term debt cost rate. Lastly, an adjustment is made to reduce the  
9 annualized cost of long-term debt to reflect the fact that Distribution  
10 has recovered a portion of the after-tax refinancing premiums. The  
11 rationale for these refinancing adjustments is consistent with  
12 testimony sponsored by Distribution witnesses in Docket Nos. R-  
13 0038168 and R-0049656 and continues to have merit.

14 Short Term Debt

15 Q. Please describe National Fuel's available sources of short-term  
16 borrowings.

17 A. National Fuel has established both uncommitted and committed  
18 lines of credit and a commercial paper program. These facilities  
19 have been established for general corporate purposes and are  
20 used to finance the system's working capital needs. National Fuel  
21 currently has arrangements to borrow up to \$445 million under

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1 various bilateral uncommitted lines of credit. Uncommitted credit  
2 lines are generally callable at the option of the financial institution.  
3 National Fuel may also issue short-term debt under its commercial  
4 paper program. The amount available under that program is  
5 currently \$200 million, but National Fuel intends to increase the size  
6 of the commercial paper program to \$300 million. The commercial  
7 paper program is backed by a syndicated committed credit facility  
8 totaling \$300 million. Because it restricts the ability of an institution  
9 to call the line due to events not specific to the borrower, a  
10 committed line of credit provides assurance that credit will be made  
11 available even when credit may be limited due to disruptions in the  
12 credit markets. Because of this assurance of availability, financial  
13 institutions charge a fee for providing a committed line. National  
14 Fuel's establishment of a committed line of credit is consistent with  
15 the requirements contained in Standard and Poor's Credit Policy  
16 Statement on commercial paper backup.

17 Q. What short-term debt cost rates do you utilize?

18 A. I utilize National Fuel's actual January 31, 2006 short-term debt  
19 cost rate of 4.35% and the estimated rate at January 31, 2007 of  
20 6.03%.

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1 Q. How was the short-term interest rate of 6.03% provided in Exhibit  
2 406, Schedule 1, Page 3 developed?

3 A. The short term interest rate projected in Exhibit 406, Schedule 1,  
4 Page 3 consists of two parts: 1) the short term borrowing rate  
5 charged by the Company's lenders and 2) the fees incurred by the  
6 Company for rating agency services and a committed line of credit.  
7 The short term borrowing rate was forecasted to be 5.3%. The  
8 committed line of credit fee experienced by the Company is 0.73%.  
9 The composite short term cost rate is 6.03%, which is equal to the  
10 sum of the 5.3% short term borrowing rate plus the 0.73%  
11 committed line of credit fee.

12 Q. How was the forecasted 5.3% short-term borrowing rate  
13 determined?

14 A. First I established National Fuel's current borrowing rate. The term  
15 of National Fuel's borrowings under its uncommitted lines of credit  
16 and commercial paper programs typically ranges from overnight to  
17 thirty days. Recent quotes from National Fuel's lenders indicate  
18 that National Fuel would be charged an interest rate in the range of  
19 5.1% – 5.2% for overnight borrowings and 5.2% – 5.3% for thirty  
20 day borrowings. Thus, depending on the length of the borrowing,  
21 National Fuel would currently expect to pay a short-term interest

**National Fuel Gas Distribution Corporation  
Direct Testimony Of David P. Bauer**

1 rate of between 5.1% - 5.3%. Since the duration of National Fuel's  
2 borrowings can vary based upon its working capital needs, I chose  
3 5.2% (the middle of the range of 5.1% - 5.3%) as an estimate of  
4 National Fuel's current borrowing costs.

5 Next, using National Fuel's current short-term borrowing cost of  
6 5.2% as a starting point, I estimated National Fuel's short-term  
7 borrowing rate at the end of the future test year. The Consensus  
8 Forecast of U.S. Interest Rates published in the most recent Blue  
9 Chip Economic Indicators (May 1, 2006) indicates that the nation's  
10 leading economists expect virtually every benchmark short-term  
11 interest rate (including the Federal Funds, 3-month LIBOR, 1-month  
12 commercial paper and 3-month Treasury bill rates) to increase by  
13 10 basis points by the first quarter of 2007. Since those benchmark  
14 rates underlie the interest rates charged to National Fuel by its  
15 lenders, it is reasonable to assume that National Fuel's short-term  
16 borrowing rates will also increase by 10 basis points by the first  
17 quarter of 2007. Therefore, I added 10 basis points to National  
18 Fuel's current 5.2% short-term borrowing rate to arrive at its  
19 forecasted 5.3% short-term borrowing rate at the end of the future  
20 test year.

21 Pension Cost

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1 Q. What is the current treatment of pension costs in Distribution's  
2 rates?

3 A. Distribution provides pensions upon retirement to most full-time  
4 employees hired in 2003 or prior (National Fuel closed its pension  
5 plan to new entrants effective November 1, 2003 for union  
6 employees and effective July 1, 2003 for non-union employees).  
7 Benefits are generally based on, among other things, an  
8 employee's total years of service and compensation during  
9 employment. For ratemaking purposes, Distribution consistently  
10 has reflected as its pension expense an amount computed by  
11 reference to its anticipated cash contribution for pensions.

12 Q. How is the cash contribution calculated?

13 A. The quantification of the annual cash contribution requires the  
14 extensive use of assumptions including, but not limited to,  
15 projections of future discount rates, returns on plan assets,  
16 compensation levels, mortality, and employee turnover. To assist it  
17 in developing reasonable estimates of prospective pension  
18 expense, National Fuel utilizes the services of Mercer Human  
19 Resource Consulting ("Mercer") of Rochester, New York, as its  
20 outside actuarial consultant. Working with National Fuel's  
21 personnel, Mercer prepares a report annually that analyzes past

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1 financial results, evaluates current and future economic conditions  
2 and quantifies a range of amounts that National Fuel may  
3 contribute for pensions in a given year. The low end of the range  
4 represents the minimum contribution necessary to comply with the  
5 provisions of the Employee Retirement Income Security Act of 1974  
6 ("ERISA"). The top end of the range represents the maximum  
7 pension contribution that is deductible on a current basis under the  
8 Internal Revenue Code. Based upon this information, and  
9 information concerning future projected contributions, National Fuel  
10 makes a determination as to the annual contribution. The amount  
11 of the contribution is then determined for each portion of the  
12 National Fuel corporate system, including Distribution's  
13 Pennsylvania Division.

14 Q. How much will Distribution's Pennsylvania Division contribute in  
15 fiscal 2006?

16 A. National Fuel's Retirement Committee, with the assistance of  
17 Mercer, concluded that National Fuel's annual contribution for fiscal  
18 2006 would be approximately \$22.25 million. The Pennsylvania  
19 Division's share of that contribution is \$3,624,061. At this time,  
20 based upon information provided by Mercer, it is the Retirement

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1 Committee's intention to continue funding at the current level for the  
2 foreseeable future (i.e., \$3,624,061 for the Pennsylvania Division).

3 Q. Please explain the Exhibits that contain Distribution's claim for  
4 pension expense.

5 A. I have provided two exhibits for pension expense. Exhibit No. 4  
6 Schedule 2 (Benefits) Page 11 normalizes the historic test year for  
7 the twelve months ended January 31, 2006. Exhibit No. 104  
8 Schedule 2 (Benefits) Page 13 provides the pension expense for  
9 the twelve months ending January 31, 2007.

10 Shown at the top of Exhibit No. 104 Schedule 2 (Benefits)  
11 Page 13 is the normalized pension contribution of \$3,624,061. This  
12 is the amount of the expected pension contribution for the year  
13 February 1, 2006-- January 31, 2007.

14 The next entry on the Exhibit in the amount of \$1,080,974  
15 represents a four-year amortization of the pension deferral set up  
16 via the R-038168 settlement and is calculated at the bottom of the  
17 Exhibit.

18 As shown on the top half of the Exhibit, the sum of  
19 normalized cost of \$3,624,061 and the amortization of \$1,080,974  
20 is \$4,705,035. This is then multiplied by 77.00% (Factor A of  
21 Exhibit No. 13 Schedule 4). The effect of this adjustment is to

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1           reduce both the normalized contribution and the amortization of the  
2           deferral to the amount that will be charged to operation and  
3           maintenance expenses as these amounts are recovered. The  
4           remainder will follow the employee wages and salaries to capital  
5           accounts, clearing accounts and non-jurisdictional accounts. The  
6           operation and maintenance amount is \$3,622,877, which is the  
7           pension expense to be used in establishing rates in this  
8           proceeding.

9           Post-retirement Benefit Costs

10          Q.    Please explain the Exhibits that contain Distribution's claim for post-  
11               retirement benefit cost.

12          A.    I have provided two exhibits for post-retirement benefit cost.  
13               Exhibit No. 4 Schedule 2 (Benefits) Page 12 normalizes the historic  
14               test year the twelve months ended January 31, 2006. This  
15               normalization takes into account the FAS 106 amount for the twelve  
16               months ended January 31, 2006 of \$7,899,260 and the  
17               normalization of the R-038168 and R-049656 Settlement annual  
18               amortization amounts of \$2,228,176 and \$502,673, respectively.  
19               Exhibit No. 104 Schedule 2 (Benefits) Page 14 provides the post-  
20               retirement cost for the twelve months ending January 31, 2007.

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1 Q. What is Distribution's post-retirement benefit cost for the future test  
2 year and how was it determined?

3 A. Distribution's post-retirement benefits cost for the twelve months  
4 ending January 31, 2007 is \$11,237,484 and is comprised of four  
5 components as shown on Exhibit No. 104 Schedule 2 (Benefits)  
6 Page 14.

7 The major component is the post-retirement benefit cost for  
8 the twelve months ended January 31, 2007 of \$6,863,730. This  
9 amount was calculated using information from a post-retirement  
10 benefit valuation prepared by Mercer. The calculation of the  
11 \$6,863,730 amount is set forth at the bottom of Exhibit No. 104  
12 Schedule 2 (Benefits) Page 14. The valuation prepared by Mercer  
13 is incorporated into Exhibit No. 4 Schedule 7.

14 The second and third components are amortizations of  
15 previously deferred under-collections of post-retirement costs.  
16 Distribution's post-retirement benefit funding mechanism, as  
17 approved by the Commission, provides that differences between  
18 the rate allowance for post-retirement benefit costs and actuarial  
19 valuations, whether positive or negative, will be expensed or  
20 credited in future proceedings. The second component is a post-  
21 retirement benefit cost deferral that was established in Case R-

**National Fuel Gas Distribution Corporation**  
**Direct Testimony Of David P. Bauer**

1           038168 and is being amortized over a four-year period in the  
2           amount of \$2,228,176. The third component is a post-retirement  
3           benefit cost deferral that was established in Case R-049656 and is  
4           being amortized over a two-year period in the amount of \$502,673.

5           The fourth component is the proposed amortization of the  
6           cumulative difference between the annual rate allowance and the  
7           annual actuarial valuation for the period February 2005 through  
8           January 2007. Distribution is proposing that the deferral be  
9           amortized over a one-year period.

10    Q.    Does this complete your testimony?

11    A.    Yes, at this time.

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

1 Q. State your name and business address.

2 A. My name is Thomas J. Clark. My business address is 6363 Main Street,  
3 Williamsville, New York 14221.

4 Q. By who are you employed and in what capacity?

5 A. I am employed by National Fuel Gas Distribution Corporation  
6 ("Distribution") as a Senior Rate Analyst in Distribution's Rates and  
7 Regulatory Affairs Department.

8 Q. Describe briefly your educational background and experience.

9 A. In 1975, I graduated from the State University of New York at Alfred, New  
10 York with an Associate of Business Administration degree, and I began  
11 my employment with Distribution as a clerk assigned to the Rate  
12 Department. In 1980, I received a Bachelor of Business Management  
13 degree from the State University of New York at Buffalo, and I was  
14 promoted to Assistant Accountant. In 1981 I was promoted to Rate  
15 Analyst and in 1997 I was promoted to my present position of Senior Rate  
16 Analyst.

17 Q. What is the purpose of your testimony?

18 A. I am testifying to the rate design as proposed by Distribution for the  
19 increase of \$25,892,000 in revenues as shown in the proposed rate  
20 section of Exhibit No. 103. Exhibit Nos. 111, Schedules 1 through 3,  
21 further supports this.

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Direct Testimony Of Thomas J. Clark

1 Q. Have you reviewed Distribution's cost of service study as shown in Exhibit  
2 No. 111, Schedule 4 and as explained in Ms. Truitt's testimony, Statement  
3 No. 105?

4 A. Yes, I have.

5 Q. How can cost study results provide guidelines for rate design?

6 A. Results of a class allocated cost-of-service study provide cost guidelines  
7 for use in evaluating class revenue levels and class rate structures. With  
8 regard to rate class revenue levels, the rate of return results show that  
9 certain rate classes are being charged rates that recover less than their  
10 indicated cost of service. By adjusting rates in accordance with the cost  
11 study, rate class revenue levels can be brought closer in line with the  
12 indicated costs of service, resulting in movement of rate class rates of  
13 return toward the system average rate of return and resulting in rates that  
14 are more in line with the cost of providing service. Concerning cost  
15 justification of rates within each rate class, the classified costs, as  
16 allocated to each class of service in the cost study, provide cost  
17 information that can be of assistance in determining the need for changes  
18 in the relative levels of demand, customer and commodity rate block  
19 charges.

20 Q. Beside the cost guideline just mentioned, explain other guidelines or  
21 criteria that should be considered in the design of gas utility rates.

22 A. The design of gas utility rates must, of course, be just and reasonable and  
23 avoid unreasonable discrimination. Where rates need to be adjusted

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

1 toward the achievement of proper cost recovery, customer impact  
2 considerations should also be factored into the rate design process.

3 Market conditions within the utility service territory, relating to the  
4 competitive environment faced by the Company's customers, should also  
5 be reviewed. Competition from unregulated suppliers of natural gas and  
6 alternate fuels and the prices of such alternative sources of gas and  
7 alternate fuels relative to Distribution's current and proposed rates, the  
8 number of price-sensitive customers and the potential for load loss due to  
9 customers switching to other suppliers of natural gas or other fuels are  
10 other factors that should be considered in designing rates. Loss of  
11 customers and gas volumes, as a result of customers' switching to  
12 alternate fuels or other suppliers or other market-based factors such as  
13 production migration to more competitive regions, can, in the short term,  
14 affect a gas utility's ability to recover fully its fixed costs and can reduce a  
15 gas utility's chances of earning the allowed rate of return, as determined  
16 by a state regulatory body and, in the long term, can result in increased  
17 rates for other customers.

18 Further, rates should provide financial and earnings stability to  
19 Distribution. Toward this goal, it is generally not sound ratemaking  
20 practice to provide for recovery of a substantial portion of fixed costs, such  
21 as customer-related costs that bear no relationship to customer gas  
22 consumption patterns, in the rate block portion of the rate schedule.

23 Recovery of fixed costs through commodity rates detracts from earnings

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

1 stability because the revenues generated from customers' volumetric use  
2 of gas can be greatly sensitive to temperature variation and thus subject  
3 to recovery from sales volumes and revenues that fluctuate. Recovery of  
4 fixed costs through commodity rates can also unfairly burden large  
5 heating customers with the burden of providing revenue cost recovery of  
6 costs incurred to service lower-volume customers, such as seasonal or  
7 recreational residences.

8 Q. Generally speaking, how are guidelines or criteria, such as the ones just  
9 mentioned, incorporated into the rate design process?

10 A. The rate design process, which includes both the apportionment of  
11 revenues to be recovered among customer classes and the determination  
12 of rate structures within customer classes, consists of finding a  
13 reasonable balance between the various criteria or guidelines that relate  
14 to the design of utility rates. Economic, regulatory, historical and social  
15 factors all enter into the process. In other words, both quantitative and  
16 qualitative information is evaluated before reaching a final rate design  
17 determination. Of necessity then, the rate design process has to be, in  
18 part, influenced by judgmental evaluations.

19 Q. Do the proposed base rates as designed reflect an increased revenue  
20 requirement of \$25,892,000?

21 A. Yes, they do. \$25,892,000 is the amount of the proposed increase in  
22 annual operating revenues, based upon the level of operations for the

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

1 twelve months ending January 31, 2007, as adjusted, including "other  
2 operating revenues".

3 Q. Describe the approach generally followed to allocate the proposed  
4 revenue increase to the various rate classes.

5 A. As described earlier, the apportionment of revenues among rate classes  
6 consists of deriving a reasonable balance between the various criteria or  
7 guidelines that relate to the design of utility rates. The criteria that were  
8 considered in the process included: (1) cost of service; (2) class  
9 contribution to present revenue levels; (3) market conditions; and (4)  
10 customer impact considerations. These criteria were evaluated for each  
11 of Distribution's rate classes. Based on the evaluation of the above-  
12 mentioned criteria, adjustments of class revenue levels were made so that  
13 the class rates of return for each rate class approach a more equal level  
14 while recognizing the concept of gradualism in rate changes. The current  
15 competitive circumstances of Distribution's service territory as well as the  
16 competitive evolution of the natural gas industry were also considered in  
17 the proposed allocation of the overall revenue requirement and design of  
18 unit rates for each rate class.

19 Q. Why did Distribution utilize four different costs of service studies in  
20 developing class revenue levels to move toward equal rates of return?

21 A. The selection of any cost of service study for use in designing rates is a  
22 somewhat subjective process. By using four different studies, I have  
23 attempted to incorporate and give some weight to the principal

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

1 considerations advocated by a cross section of cost of service experts. It  
2 is to be emphasized that each of the studies contains components that  
3 are explained in the American Gas Association's Gas Rate Fundamentals  
4 (Third Edition), indicating that each approach is considered to have merit  
5 by industry experts.

6 Q. Hasn't the Commission, in past Distribution cases, decided that the Peak  
7 and Average allocation methodology with no customer component of  
8 distribution mains has been the most useful study in determining the  
9 contribution to the overall revenue requirement from each rate class?

10 A. Yes, but the Commission has also recognized that other methodologies  
11 may be useful. For example in Case R-901670, the Commission  
12 recognized that the dispersion of customers throughout the service  
13 territory has a bearing on the investment required to serve them and the  
14 maintenance of the extended system. [Order at R-901670, pg. 133.]

15 Q. Are there any other reasons why the results of four different studies  
16 should be used in developing rates in this proceeding?

17 A. The natural gas industry has also undergone fundamental change since  
18 the Commission last rendered a decision regarding the use of cost of  
19 service studies in development of Distribution's base rates. The  
20 fundamental change has occurred both at the federal regulatory level and  
21 the change in pricing policies for natural gas at the state level. Changes  
22 in regulation at the federal level include an expanding commitment to non-  
23 discriminatory open access transportation service. This commitment has

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

1 increased the competitive threat of large customers bypassing Distribution  
2 service through direct interconnection with federally regulated upstream  
3 pipelines.

4 The FERC, in Order No. 636, has implemented straight fixed variable  
5 ("SFV") rate design which, in effect, allocates 100% of transmission plant  
6 as demand related. In the past, the FERC had advocated allocation  
7 methodologies which allocated a portion of demand related costs to  
8 commodity rates. The FERC's move to SFV rate design recognizes that  
9 rates should reflect how costs are incurred. Distribution's inclusion of cost  
10 of service studies which utilizes the peak allocation methodology  
11 recognizes this trend.

12 Q. How were market conditions considered in Distribution's apportionment of  
13 revenues among the rate classes?

14 A. As more fully explained by Mr. Swartzfager in Statement No. 14, market  
15 conditions within Distribution's service territory are an important  
16 consideration in establishing rate levels for Distribution's more  
17 competitively oriented market segments. Because these customers have  
18 competitive alternatives, they will not pay rates that subsidize other  
19 classes of customers. For these reasons, Distribution has not proposed  
20 to increase base rates to industrial customers. Based on the cost of  
21 service studies conducted this will result in class rates of return for most  
22 industrial rate classes and for industrial customers as a whole that will  
23 remain above the system average rate of return. I note that, based on

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

1 these results to the extent that Distribution has been required to reduce  
2 industrial transportation rates to specific customers to meet competitive  
3 threats, the resulting revenue shortfall is being recovered within the  
4 industrial class of customers and is not being recovered from other  
5 customer classes.

6 Q. How were customer-impact considerations factored into the rate design  
7 process?

8 A. Customer impact considerations were factored into the process of  
9 designing the proposed customer charges and block rates of the  
10 individual rate classes.

11 Q. How were the proposed base rates designed?

12 A. As addressed Mr. Meini's testimony, there are significant rate design and  
13 rate structure proposals. I will discuss the steps in designing the rates  
14 and the rate structure changes. The first step was to determine the  
15 overall allocation of the revenue increases among the classes. Based on  
16 the cost of service study results and competitive considerations, the  
17 proposed increase in revenues was allocated to the Residential, Small  
18 Commercial and Public Authority (Less than 250 Mcf annual  
19 consumption), Small Commercial and Public Authority (Greater than 250  
20 Mcf annual consumption) and the Large Commercial and Public Authority  
21 classes. The allocation of the increase was calculated as follows:

22

23

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

Class	Non Gas Cost Revenue (1) (000)	% of Non Gas Revenue (2)	Increase after Late Payment (3) (000)
Residential	73,546	78.16%	20,161
Sm. C/PA < 250	4,161	4.42%	1,141
Sm. C/PA > 250	4,833	5.14%	1,325
Lg. C/PA	11,559	12.28%	3,168
Total	94,099	100.00%	25,795

1

2 The increase after late payments of \$25,795,000 is equal to the overall  
3 increase of \$25,892,000 less projected increase in late payments  
4 associated with the increase request of \$97,000.

5 The next step was to determine the proposed customer and usage  
6 charges for each of these rate classes. The derivation of the proposed  
7 rates proceeded along five steps.

8 Step (1) was the allocation of the increase to the service  
9 classifications discussed previously.

10 Step (2) was the determination of the proposed customer and usage  
11 charges for each of these rate classes. The determination was made after  
12 reviewing the customer cost level of each proposed rate class. Exhibit  
13 No. 111, Schedule 4 derived the customer cost for each rate class from  
14 the cost study in Exhibit No. 111-A, Schedule 1. In Distribution's rate case  
15 (R-901670), the Commission stated (at pages 145 and 146 of its Opinion

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

1 and Order), "We continue to believe that customer charges should be  
2 based on cost causation to the extent that gradualism will allow." It is  
3 proposed that the customer charges be increased to the level of cost for  
4 customer classes that receive an increase. For the residential customer  
5 class it is proposed that the increase be applied to the customer charge.  
6 Any remaining increase was then allocated to the remaining blocks of  
7 residential rates. Increases to the Small Commercial and Public Authority  
8 Class (less than 250 Mcf) rates were applied to the customer charge and  
9 the remaining rate blocks. Increases to the Small Commercial and Public  
10 Authority Class (greater than 250 Mcf) rates were applied to the customer  
11 charge and the remaining rate blocks. Increases to the Large  
12 Commercial and Public Authority Class (greater than 1,000 Mcf) were  
13 applied to the commodity rate blocks.

14 The Administrative charges for Monthly Metered Transportation  
15 ("MMT") customers and Daily Metered Transportation ("DMT") customers  
16 have been eliminated. For industrial classes that did not receive a base  
17 rate increase the administrative charges were rolled in to the basic service  
18 charge. In addition, for MMT and DMT commodity rates for Large  
19 Commercial/Public Authority, Intermediate Volume Industrial and Large  
20 Volume Industrial classes the intrastate/interstate rate differential was  
21 eliminated and a composite rate was developed for each customer class.

22 Step (3) is the calculation of winter / non-winter seasonal gas cost.  
23 The Demand NGS and the Demand DC cost which are currently being

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

1 recovered from customers over a twelve-month period is being proposed  
2 to be recovered over the period December – March. As shown on Exhibit  
3 No. 112, Schedule 5, the seasonal gas cost rate for the winter period is  
4 proposed to be \$13.9087/Mcf compared to current gas cost rates of  
5 \$13.0432/Mcf that are in effect as of February 1, 2006. This is an  
6 increase in gas cost of \$0.8655/Mcf. For the non-winter months of April –  
7 November there would be no recovery of demand related gas cost and  
8 the proposed gas cost rate would be \$11.3271/mcf. This is a decrease of  
9 \$1.7161/Mcf. There would be no change to the commodity rate. The  
10 commodity costs would be recovered over a full twelve-month period.  
11 Under this proposal total gas cost for the twelve-month period would not  
12 change but there would be a redesign of gas cost between customer  
13 classes.

14 Step (4) is the redesign of the Residential, Small Commercial/Public  
15 Authority (less than 250 Mcf) and Small Commercial/Public Authority  
16 (greater than 250 Mcf) customer classes where tailblock rates were  
17 reduced and penultimate block rates were increased. This change is  
18 recommended to help mitigate the extreme volatility on the customer's  
19 winter bills. The penultimate block was increased by \$1.7161/Mcf and the  
20 non-gas cost increase in the penultimate block decreased the tailblock.

21 Step (5) is the rate for the Merchant Function Charge. The Merchant  
22 Function Charge is a proposal for certain cost of service non-gas costs  
23 that are associated with storage working capital costs and a portion of

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

1 uncollectible expenses be included with the purchase gas cost rate for  
2 billing purposes. Separate merchant function charges (based on a  
3 merchant charge factor) for residential and non-residential customer  
4 classes were developed. It is proposed that the merchant function charge  
5 in effect be equal to the merchant charge factor multiplied by the natural  
6 gas supply charge and the gas adjustment charge in effect for the month.  
7 The winter merchant function charge for residential customers is proposed  
8 to be \$.4128/Mcf ( $3.069951\% \times (\$13.4718 - \$0.0263)$ ). The non-winter  
9 residential merchant function charge is proposed to be \$.3478/Mcf  
10 ( $3.069951\% \times (\$11.2925 + \$0.0346)$ ). The non-winter merchant function  
11 charge for non-residential customers is proposed to be \$.1083/Mcf  
12 ( $.805409\% \times (\$13.4718 - \$0.0263)$ ). The non-winter merchant function  
13 charge for non-residential customers is proposed to be \$.0913/Mcf  
14 ( $.805409\% \times (\$11.2925 + \$0.0346)$ ). The merchant function factor would  
15 not change from month to month but would be applied to the gas cost  
16 rates that the Company files on a quarterly basis.

17 Q. Describe Exhibit No. 111-Schedule 1.

18 A. This exhibit provides a bill frequency analysis for each rate schedule and  
19 block interval, the number of bills at each interval, the cumulative number  
20 of bills at each interval, the Mcf at each interval, the accumulation of Mcf  
21 passing through each interval, and revenue at each interval at both  
22 present and proposed winter / non-winter rates. The bill frequency  
23 presented on Exhibit No. 111-Schedule 1 provides the projected

National Fuel Gas Distribution Corporation  
Direct Testimony Of Thomas J. Clark

1 consumption by rate blocks for the twelve months ending January 31,  
2 2007.

3 Q. Describe Exhibit No. 111-Schedule 2.

4 A. Exhibit No. 111-Schedule 2, consisting of eighteen pages, contains  
5 graphs of present and proposed winter / non-winter rates that are drawn  
6 on computer-generated, hyperbolic cross-section paper. This form of  
7 graphical representation most effectively illustrates rates on a straight-line  
8 basis. The advantages of using straight-line graphs are numerous, e.g.,  
9 the graph may be more readily and accurately drawn after determination  
10 of only a few points: changes in the slope of the graph may be more easily  
11 located on a straight line than on a curve; and as rate design in many  
12 instances consists of designing new rates having fixed relations to existing  
13 rates, crossing points and differences or relations of slopes may also be  
14 determined more readily with straight lines than curves.

15 Q. Describe Exhibit No. 111-Schedule 3.

16 A. This exhibit, consisting of eighteen pages, presents a tabulation of base  
17 rate bills for each rate schedule comparing, in amount and percent, the  
18 existing rates to proposed winter / non-winter rates. The designated gas  
19 consumption values represent a range of usage from very small (mostly  
20 residential) to large industrial gas users.

21 Q. Does this conclude your testimony?

22 A. Yes, at this time.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION  
(PENNSYLVANIA DIVISION)

DIRECT TESTIMONY

OF

FRANK J. HANLEY, CRRA  
PRESIDENT  
AUS CONSULTANTS – UTILITY SERVICES

CONCERNING

FAIR RATE OF RETURN

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## TABLE OF CONTENTS

	<u>Page No.</u>
I. INTRODUCTION	1
II. SUMMARY	2
III. GENERAL PRINCIPLES	8
IV. BUSINESS RISK	8
V. FINANCIAL RISK	11
VI. NFG AND NFGDC	13
VII. PROXY GROUPS	13
VIII. CAPITAL STRUCTURE	16
IX. DEBT COST RATES	22
X. COMMON EQUITY COST RATE MODELS	22
A. The Efficient Market Hypothesis (EMH)	22
B. Discounted Cash Flow Model (DCF)	26
1. Theoretical Basis	26
2. Applicability of a Market-Based Common Equity Cost Rate to a Book Value Rate Base	28
3. Application of the DCF Model	31
a. Dividend Yield	31
b. Discrete Adjustment of Dividend Yield	32
c. DCF Growth Rates	32
4. Conclusion of DCF Cost Rates	34
C. The Risk Premium Model (RPM)	34
1. Theoretical Basis	34
2. Estimation of Expected Bond Yields	36
3. Estimation of the Equity Risk Premiums	37
4. Conclusion of RPM Cost Rates	43
5. The RPM Does Not Presume a Constant Equity Risk Premium	43
D. The Capital Asset Pricing Model (CAPM)	44
1. Theoretical Basis	44
2. Risk-Free Rate of Return	46
3. Market Equity Risk Premium	47
4. Conclusion of CAPM Cost Rates	49
E. The Comparable Earnings Model (CEM)	49
1. Theoretical Basis	49
2. Application of the CEM	51
3. Selection of Market-Based Companies of Similar Risk	51
4. Conclusion of CEM Cost Rates	54
XI. CONCLUSION OF COMMON EQUITY COST RATE	54
A. Conclusion of Common Equity Cost Rate Must Be Based on the Application of Multiple Models	54
XII. REALITY CHECKS	57

Appendix A – Professional Qualifications of Frank J. Hanley

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1

I. INTRODUCTION

2 Q. Please state your name, occupation and business address.

3 A. My name is Frank J. Hanley and I am President of AUS Consultants – Utility Services.  
4 My business address is 155 Gaither Drive, P.O. Box 1050, Moorestown, New Jersey  
5 08057.

6 Q. Please summarize your educational background and professional experience.

7 A. I have testified as an expert witness on rate of return and related financial issues before  
8 33 state public utility commissions, including the Pennsylvania Public Utility Commission,  
9 the Public Services Commission of the Territory of the U.S. Virgin Islands, and the  
10 Federal Energy Regulatory Commission. I have also testified before local and county  
11 regulatory bodies, an arbitration panel, a U.S. Bankruptcy Court, the U.S. Tax Court and  
12 a state district court. I have appeared on behalf of investor-owned companies,  
13 municipalities, and state public utility commissions. The details of these appearances, as  
14 well as my educational background, are shown in Appendix A supplementing this  
15 testimony.

16 Q. What is the purpose of your testimony?

17 A. The purpose of my testimony is to provide evidence on behalf of National Fuel Gas  
18 Distribution Corporation (NFGDC or the Company) in the form of a study of the common  
19 equity cost rate which it should be afforded an opportunity to earn on the common equity  
20 financed portion of its jurisdictional rate base for the future test year ended January 31,  
21 2007 and to support the reasonableness of the use of a ratemaking capital structure  
22 consisting of 48.50% total debt and 51.50% common equity capital.

23 Q. What is your recommended fair rate of return?

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 A. It is a range of 9.32% to 9.45% applicable to a ratemaking capital structure consisting of  
2 48.50% total debt and 51.50% common equity capital. The long- and short-term debt  
3 cost rates were provided to me by NFGDC. My recommended range of common equity  
4 cost rate is 12.00% - 12.25%. NFGDC has chosen to request the high end of the range,  
5 or 12.25%, as explained in the testimony of NFGDC Witness Eric Meinl.

6 Q. Have you prepared an exhibit which supports your recommended range of common  
7 equity cost rate and the resultant range of overall fair rate of return?

8 A. Yes, I have. It has been marked for identification as Exhibit No. 400 and consists of 16  
9 schedules.

10 **II. SUMMARY**

11 Q. Please summarize your recommended range of overall cost of capital and fair rate of  
12 return relative to the future test year ending January 31, 2007.

13 A. It is 9.35% - 9.48% developed as follows:

	<u>Type of Capital</u>	<u>Ratios</u>	<u>Cost Rate</u>	<u>Weighted Cost Rate</u>
14				
15				
16				
17	Long-Term Debt	40.04%	6.64%	2.66%
18				
19	Short-Term Debt	<u>8.46</u>	6.03	<u>0.51</u>
20				
21	Total Debt	48.50		3.17
22				
23	Common Equity	<u>51.50</u>	12.00%-12.25%	6.18 - 6.31
24				
25	Total	<u>100.00%</u>		<u>9.35%-9.48%</u>
26				

27 The above recommended range of overall cost of capital is also summarized on  
28 Schedule 1, page 2 of Exhibit No. 400 based upon a ratemaking capital structure  
29 consisting of 48.50% total debt and 51.50% common equity. Also shown on page 1 of  
30 Schedule 1 for information purposes only are the details of the range of overall cost of

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 capital of 9.21% - 9.34% at the end of the historical test period, January 31, 2006. As  
2 explained later, the difference between the overall rate of return at January 31, 2006, and  
3 at January 31, 2007, is solely related to a change in the cost rate of short-term debt.

4 My recommended range of common equity cost rate of 12.00% - 12.25% is  
5 applicable to both periods, the basis of which is summarized on Exhibit No. 400,  
6 Schedule 1, page 3. As explained in detail infra, my recommendation reflects current  
7 capital market conditions and results from the application of four well-tested market-  
8 based cost of common equity models, the Discounted Cash Flow (DCF) approach, the  
9 Risk Premium (RP) Model, the Capital Asset Pricing Model (CAPM), and the Comparable  
10 Earnings Model (CEM).

11 Q. Please summarize your testimony.

12 A. When a company such as NFGDC has common stock which is not traded, it is common  
13 to observe the market-based common equity cost rates of similar risk companies (proxy  
14 groups) for insight into a recommended common equity cost rate for use in a cost of  
15 capital determination, and to verify the reasonableness of a capital structure used for  
16 ratemaking purposes when the capital structure of the regulated utility is not appropriate  
17 to use and the parent company's capital structure, while reasonable, is at the high end of  
18 the range of reasonableness.

19 NFGDC is a wholly-owned subsidiary of National Fuel Gas Company (NFG).  
20 Consequently, NFGDC's common stock is not traded. For reasons discussed infra, NFG  
21 is a reasonable proxy for determining the common equity risk rate of a local gas  
22 distribution company (LDC), specifically NFGDC. However, for reasons which will be  
23 discussed infra, NFG's expected January 31, 2007 capital structure includes 54.16%  
24 common equity ratio which is close to the high end of Standard & Poor's (S&P) range of

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 total equity required for an A bond rating of an LDC with a business profile of "4". In  
2 order to be conservative, I adopt the middle of that range, or a common equity ratio of  
3 51.50%. I then look to proxy groups of similar risk LDCs, whose common stocks are  
4 actively traded, for insight into an appropriate common equity cost rate applicable to  
5 NFGDC. The use of other firms of similar risk as proxies is consistent with the principles  
6 of fair rate of return established in the Hope<sup>1</sup> and Bluefield<sup>2</sup> cases and adds reliability to  
7 the exercise of informed expert judgment in arriving at a recommendation of common  
8 equity cost rate. Consequently, I have evaluated the market data of two proxy groups of  
9 LDCs and adjusted the common equity cost rates derived therefrom to reflect NFGDC's  
10 unique (greater) risks vis-à-vis those proxies.

11 My recommended range of common equity cost rate of 12.00% - 12.25% reflects  
12 current capital market conditions and results from the application of the four well tested  
13 market-based cost of common equity models mentioned supra, namely the DCF, RPM,  
14 CAPM, and CEM models. It is based upon two proxy groups of LDCs; a group of four  
15 and a group of nine Value Line (VL) LDCs because NFGDC's common stock is not  
16 traded and its parent's market prices are not reflective of the risks associated with a LDC  
17 because NFG is significantly engaged in the pipeline and storage business as well as a  
18 number of unregulated businesses including exploration and production, energy  
19 marketing and timber in addition to the gas distribution business. Thus, NFG's common  
20 equity cost rate is not indicative of the common equity cost rate applicable to its LDC  
21 business, i.e., NFGDC. It is critically important that the risk rate reflected in the cost of  
22 capital applied to NFGDC's Pennsylvania jurisdiction rate base is reflective of the risk of

---

<sup>1</sup> Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

<sup>2</sup> Bluefield Water Works Improvement Co. v. Public Serv. Comm'n, 262 U.S. 679 (1922).

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 an LDC with unique risks attributable to its small size and lack of protection from the  
2 vagaries of weather on revenues, earnings and cash flows. Consequently, the use of  
3 "comparable" risk firms as proxies is essential and consistent with the principles of fair  
4 rate of return established in the Hope and Bluefield cases mentioned supra.

5 All four of the cost of common equity models which I utilize are market-based and  
6 are predicated upon the Efficient Market Hypothesis (EMH). The prudence of relying  
7 upon all of the market-based models is affirmed by the financial literature. Because all of  
8 the models are discussed in the financial literature, the EMH requires the assumption that  
9 investors rely upon all of them. Consequently, I rely upon the four most widely-discussed  
10 and utilized cost of common equity models as principal tools in reaching my  
11 recommended equity cost rate. No single cost of common equity model is so  
12 theoretically superior to the others, or so precise, to justify sole reliance on it in the  
13 application of the traditional ratemaking paradigm.

14 As far as the DCF model is concerned, I relied upon results which have been  
15 adjusted to account for the impact of the added financial risk attributable to the  
16 divergences of the market values and book values of common stocks, especially in a  
17 volatile market. I have maintained consistently over the years that the DCF model tends  
18 to understate the true cost of common equity capital when the market values of utilities'  
19 common stocks exceed their book values. The basis for the adjustments made to  
20 account for the greater financial risk of a market-based DCF cost rate which is applied to  
21 a much lower common equity ratio measured at book value (or the common equity  
22 financed portion of an original cost rate base) is supported academically in an article by  
23 Robert S. Hamada entitled, "Portfolio Analysis, Market Equilibrium and Corporate  
24 Finance" as published in the Journal of Finance (Vol. 24, No. 1, March 1969, 13-31).

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1           Moreover, this Commission, in a number of cases, has adopted the use of an adjusted  
2           DCF model which accounts for the impact of the divergence of market values and book  
3           values of common stocks on DCF cost rate (financial risk adjustment). Several recent  
4           examples are Aqua Pennsylvania Water Company (R-00038805), Order entered August  
5           5, 2004 and Pennsylvania Power & Light Co. (R-00049255), Order entered December  
6           22, 2004.

7           The range of DCF cost rates adjusted to reflect the added financial risk when  
8           applied to the book value of equity is 10.30% - 10.76% before adjustment to reflect  
9           NFGDC's added risks. The Commission, in the Aqua Pennsylvania Order (R-00038805)  
10          dated July 23, 2004 (and Entered August 5, 2004, supra) specified that in *Lower Paxton*,  
11          the Court recognized that the Commission could consider other models such as those  
12          utilized by me – namely risk premium, CAPM and comparable earnings. In view of this,  
13          my use of multiple cost of equity methods is validated.

14          As a result of the foregoing use of DCF cost rates adjusted for financial risk and  
15          the use of the risk premium, CAPM and comparable earnings methods, the resultant  
16          range of common equity cost rate is 11.40% (proxy group of nine VL LDCs) to 11.60%  
17          (proxy group of four LDCs) before the necessary adjustments to reflect NFGDC's unique  
18          risks attributable to its small size and lack of protection from the vagaries of the weather  
19          vis-à-vis the proxy groups. As shown on Schedule 1, page 3 of Exhibit No. 400, at Line  
20          Nos. 6-8, the range of common equity cost rate, after adjustments to reflect NFGDC's  
21          unique risks, is from 11.87% to 12.33% calculated as follows:

22  
23  
24

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

	Proxy Group of <u>Four LDCs</u>	Proxy Group of <u>Nine VL LDCs</u>
1		
2		
3		
4	DCF	10.76%
5	Risk Premium	10.70
6	CAPM	10.37
7	Comparable Earnings	<u>14.56</u>
8		
9	Average	11.60
10		
11	Adjustment for Small Size	0.30 – 0.60
12		
13	Adjustment for Lack of WNA	<u>0.13</u>
14		
15	Range of Cost Rate	12.03%-12.33%
16		
17		11.87%-12.17%

17 That range of 11.87% - 12.33% leads me to recommend a range of 12.00% -  
18 12.25%. I also reviewed regulatory awards made to LDCs during the period January 1,  
19 2004 through March 31, 2006. The average awarded ROE in fully litigated cases was  
20 10.67% relative to a 47.30% common equity ratio. In addition, I utilize what I refer to as a  
21 practical approach to the DCF and CAPM methods. In doing so, I considered only those  
22 cost rates equal to or greater than 9.45%. I did so because 9.45% was the lowest  
23 awarded ROE by any state regulatory commission during the period January 1, 2004  
24 through March 31, 2006. In view of the consistent rise in interest rates, which is  
25 significant to capital intensive utilities, the cost of capital is rising and regulatory awards  
26 will surely be greater in the near-term future. Thus, it is entirely appropriate to consider  
27 only those DCF and CAPM results at or above 9.45%. The practical DCF results are  
28 10.72% (proxy group of four LDCs) and 10.78% (proxy group of nine VL LDCs). After  
29 those results are adjusted for financial risk, they become 12.05% and 11.98%,  
30 respectively, as shown on Line No. 5B, Schedule 1, page 3 of Exhibit No. 400.

31 When consideration is given, as will be discussed infra, to NFGDC's greater  
32 Pennsylvania jurisdictional risks due to small size, lack of protection from the vagaries of

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 the weather, along with rising interest rates which will increase the cost of capital and  
2 regulatory awarded rates of return, my recommendation is confirmed as reasonable.

3 **III. GENERAL PRINCIPLES**

4 Q. What general principles have you considered in arriving at your opinion that NFGDC's  
5 range of overall cost of capital of 9.32%-9.45% applicable to the future test year is  
6 reasonable?

7 A. In unregulated industries where the total price of a delivered product or service is not  
8 regulated, competition is the principal determinant in establishing the price. Traditionally,  
9 in the case of public utilities, regulation acts as a substitute for the competition of the  
10 marketplace. The natural gas business has become subject to increasing competitive  
11 pressures, a fact recognized by investors which is reflected in the market prices they pay  
12 for securities. Analyses based on companies whose securities are actively traded are  
13 therefore imperative. The range of common equity cost rate determined should be  
14 adequate enough to fulfill investors' requirements and assure that the entity will be able  
15 to fulfill its obligations to its customers. A utility's obligation to serve requires a level of  
16 earnings sufficient to maintain the integrity of presently invested capital and permit the  
17 attraction of needed new capital at a reasonable cost in competition with all other  
18 comparable-risk seekers of capital. These standards for a fair rate of return have been  
19 established by the U.S. Supreme Court in the Hope and Bluefield cases cited supra.

20 **IV. BUSINESS RISK**

21 Q. Please define business risk and explain why it is important to the determination of a fair  
22 rate of return.

23 A. Business risk is a collective term encompassing all of the diversifiable risks of an  
24 enterprise except financial risk. Business risk is important to the determination of a fair

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 rate of return because the greater the level of risk the greater the rate of return  
2 demanded by investors consistent with the basic financial precept of risk and return.

3 Q. Does the size of an enterprise affect the level of business risk perceived by investors?

4 A. Yes. It is well-established in the financial literature, and well noted by investors, that the  
5 size of an enterprise affects the level of its business risk. I have included information on  
6 size and risk which is shown on Schedule 1, pages 7 through 25 of Exhibit No. 400.

7 Q. Please explain why size has a bearing on business risk.

8 A. Smaller companies are less capable of coping with significant events which affect sales,  
9 revenues and earnings.

10 The loss of revenues from a few larger customers, for example, would have a  
11 greater effect on a small company than on a much larger company with a larger customer  
12 base. Size is an important factor which affects business risk and hence common equity  
13 cost rate. Thus, the cost of capital must reflect the impact of NFGDC's size (as  
14 measured by its PA jurisdictional rate base upon which a fair rate of return should be  
15 allowed, including the common equity financed portion) on common equity cost rate vis-  
16 à-vis each of my two proxy groups of LDCs. Based on my analyses, upward adjustments  
17 are necessary to be made to the common equity cost rate derived from the proxy groups.  
18 The results of my analyses, summarized on page 10 of Schedule 1, and based on all of  
19 the data on pages 7 through 25, Schedule 1, of Exhibit No. 400, indicate that upward  
20 adjustments need to be made to the cost rate derived from the proxy groups in order to  
21 reflect NFGDC's small size on cost rate as follows: proxy group of four LDCs 1.88% and  
22 nine VL LDCs 1.88%. However, as discussed infra, I adopt a range of upward  
23 adjustment of only from 30 to 60 basis points, or 0.30% - 0.60% based on the two proxy  
24 groups (Note 6, page 6 of Schedule 1). I do so in order to be very conservative while still

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 providing recognition to the impact of size on common equity cost rate. The relative size  
2 differences based upon total capitalization for the proxy groups and NFGDC's rate base  
3 are as follows:

	Total Capital (\$ millions)	Times Greater than NFGDC	Market Capitalization of Common Equity(2) (\$ Millions)	Times Greater than NFGDC
4 Proxy Group of				
5 Four LDCs	1,296.120 (1)	4.4x	1,216.986 (2)	4.0x
6 Proxy Group of				
7 Nine Value Line				
8 LDCs	1,574.495 (1)	5.3x	1,315.987 (2)	4.4x
9 NFGDC	296.951 (1)		300.966 (2)	
			296.072 (2)	

10 (1) From Schedule 1, page 10.

11 (2) From Schedule 1, page 12.

12 I have also made a study of the relative market capitalization of NFGDC vis-à-vis both  
13 proxy groups. The results are shown on page 10 of Schedule 1. NFGDC's common  
14 stock is not publicly traded. Consequently, I have assumed that if it were publicly traded,  
15 it would be selling at the average market-to-book ratio of each proxy group. Hence,  
16 NFGDC's presumed total market capitalization is estimated to be between \$296.072 and  
17 \$300.966 million based upon the 51.50% common equity financed portion of the rate  
18 base of \$284.057 million utilizing recent market/book ratios. As shown supra, based on  
19 the market capitalization data on page 12 of Schedule 1, the proxy group of four LDCs  
20 was 4.0 times larger while the proxy group of nine VL LDCs was 4.4 times larger than  
21 NFGDC. Conventional wisdom, supported by the financial literature and actual returns  
22 over time, confirms that smaller companies tend to be more risky causing investors to  
23 expect greater returns to compensate them for that greater risk.  
24  
25  
26  
27  
28  
29  
30  
31

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 Q. Can you provide an example from the financial literature which affirms a relationship  
2 between size and risk and hence common equity cost rate?

3 A. Yes. Brigham<sup>3</sup> states:  
4

5 A number of researchers have observed that portfolios of small-firms  
6 have earned consistently higher average returns than those of large-  
7 firms stocks; this is called the "small-firm effect." *On the surface, it*  
8 *would seem to be advantageous to the small firms to provide average*  
9 *returns in the stock market that are higher than those of larger firms. In*  
10 *reality, it is bad news for the small firm; what the small-firm effect*  
11 *means is that the capital market demands higher returns on stocks of*  
12 *small firms than on otherwise similar stocks of the large firms. (italics*  
13 *added)*

14  
15 In addition, as shown on Schedule 1, page 14, Ibbotson Associates states:

16 *One of the most remarkable discoveries of modern finance is that of a*  
17 *relationship between firm size and return. The relationship cuts across*  
18 *the entire size spectrum but is most evident among smaller companies,*  
19 *which have higher returns on average than larger ones. (italics added)*  
20

21  
22 Q. You have quantified supra the incremental additional common equity cost rate to  
23 NFGDC, based on the proxy groups' to be 1.88%. Why have you only utilized a range of  
24 0.30% - 0.60% to recognize NFGDC's small size?

25 A. I have utilized such a range in order to be very conservative while providing recognition to  
26 the reality of this basic financial principle, which is supported empirically in the financial  
27 literature.

28 **V. FINANCIAL RISK**  
29

30 Q. Please define financial risk and explain why it is important to the determination of a fair  
31 rate of return.

32 A. Financial risk is the additional risk created by the introduction of debt into the capital  
33 structure. Standard & Poor's (S&P) corporate bond rating criteria is contained in Exhibit

<sup>3</sup> Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition, The Dryden Press, 1989, p. 623.

*National Fuel Gas Distribution Corporation*  
Direct Testimony of Frank J. Hanley

1 No. 400, Schedule 2, which consists of 15 pages, for ten levels of business profiles at  
2 different bond ratings with "1" being considered the lowest risk and "10" the highest risk.

3 Q. Are bond ratings a good measure of investment risk?

4 A. Yes. Similar bond ratings reflect similar combined business and financial risks. Although  
5 the specific business or financial risks may differ between companies, the same bond  
6 rating indicates that the combined risks are similar because the bond rating process  
7 gives recognition to diversifiable business and financial risks. S&P expressly states that  
8 the bond rating process encompasses a qualitative analysis of business and financial  
9 risks (see pages 3 through 9 of Exhibit No. 400, Schedule 2). Differences in risk may still  
10 exist between companies with the same bond rating and would be reflected in S&P's  
11 assigned business profile, or position, i.e., the higher the assigned number (e.g., "1"  
12 through "10"), the greater the qualitative assessment of risk by S&P, and vice versa. The  
13 riskier the assigned business profile, the more stringent are the financial guidelines. It is  
14 worthy of note that NFG's S&P bond rating is "BBB+" and it has an assigned business  
15 profile of "7" under its business profile scores and revised financial guidelines (see pages  
16 10 through 15 of Exhibit No. 400, Schedule 2) in contrast to the average company in  
17 each proxy group (which will be discussed infra) which has an "A" bond rating and much  
18 less risky business profiles of "1.8" and "2.3" (Schedule 12, page 2 of Exhibit No. 400).

19 Although there is no perfect proxy by which one can differentiate common equity  
20 risk between companies, the bond rating provides excellent insight because it is the  
21 result of a thorough and comprehensive analysis of all diversifiable investment risks, i.e.,  
22 the sum of business and financial risks. In the instant matter, NFGDC's greater unique  
23 risks vis-à-vis the proxy groups, mandates the need for a greater ratemaking common  
24 equity ratio. In other words, greater business risk equates to the need for less financial

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 risk.

2

**VI. NFG AND NFGDC**

3 Q. Have you reviewed financial data for NFG, the Company's parent?

4 A. Yes, but I have shown such information only for information purposes. In Exhibit No.  
5 400, Schedule 3, page 1, I have shown the actual capital structure at fiscal years ending  
6 September 30, 2001 through 2005. I also show capitalization and financial statistics for  
7 the same five years.

8 Q. Have you also reviewed financial data for NFGDC?

9 A. Yes. NFGDC is a wholly-owned subsidiary of NFG. On page 2 of Schedule 3 of Exhibit  
10 No. 400, I have shown NFGDC's capitalization and financial statistics for the years 2001-  
11 2005, inclusive, while page 3 of Schedule 3 contains notes relevant to pages 1 and 2.  
12 NFGDC's common equity ratio based on total capital (including short-term debt) ranged  
13 between 55.00% in 2005 and 59.31% in 2004.

14

**VII. PROXY GROUPS**

15 Q. You previously mentioned that you observed the market data for a proxy group of four  
16 LDCs in order to gain insight into a market-based common equity cost rate for NFGDC.  
17 Please explain the basis of selection of those companies.

18 A. The basis of selection was to include those LDCs: (1) which have an S.I.C. Code of 4924  
19 (Natural Gas Distribution) by S&P's Compustat/Research Insight; (2) which have actively  
20 traded common stock; (3) which are included in Value Line Investment Survey (Standard  
21 Edition) and have ThomsonFN/FirstCall long-term consensus EPS growth rates; (4)  
22 have not cut or omitted their common stock dividends during the five calendar years  
23 ending 2005 and up to the time of preparation of this testimony; (5) which derived at least  
24 80% of their 2005 operating revenues from natural gas distribution operations; (6) which

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1           were not expected to be acquired by or merged into another company at the time of the  
2           preparation of this testimony; and (7) which are included in S&P's Compustat PC  
3           Plus/Research Insight Data Base. The related capitalization and financial statistics for  
4           the companies which met the above criteria, i.e., the proxy group, are shown in Exhibit  
5           No. 400, Schedule 4.

6           Q.     Please describe Exhibit No. 400, Schedule 4.

7           A.     Schedule 4 consists of four pages. Average capitalization and financial statistics for the  
8           years 2001 through 2005, as well as the five-year averages ending 2005 for the group  
9           are shown on page 1. Notes related to page 1 are shown on page 2, as are the selection  
10          criteria and the identities of the four companies comprising the group. Page 3 contains  
11          the capitalization ratios by company and year as well as the five-year average by  
12          company and for the group. Page 4 contains information related to each company and  
13          its ability to protect itself against the vagaries of the weather.

14                   As shown on page 1, the average company in the proxy group had total capital  
15                   employed in 2005 of about \$1.296 billion, making the average company in this group  
16                   somewhat larger than NFGDC (with a rate base of \$296.951 million). The five-year  
17                   average ROE was 11.77% in contrast to NFGDC's 9.39%. The group had a five-year  
18                   average total equity ratio of 45.49% which was within the new S&P financial guideline for  
19                   an A bond rating and an average business profile of "1.8".

20          Q.     Please explain how your second proxy group of nine VL LDCs was selected.

21          A.     The basis of selection was to include those LDCs: 1) which are included in Value Line  
22                   Investment Survey's (Standard Edition) – Natural Gas (Distribution) Industry; 2) which  
23                   have actively traded common stock and have ThomsonFN/FirstCall long-term consensus  
24                   EPS growth rates; 3) which have not cut or omitted their common stock dividend during

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 the five calendar years ending 2005 and up to the time of the preparation of this direct  
2 testimony; 4) which in 2005 had at least 60% of operating revenues derived from gas  
3 operations; 5) which at the time of the preparation of this testimony were not expected to  
4 be acquired by or merged into another company; and 6) which are included in S&P's  
5 Compustat PC Plus/Research Insight Data Base.

6 The following companies were excluded from the group for these reasons:  
7 Southwest Gas Corporation does not have ThomsonFN/FirstCall projected five-year  
8 growth rate in EPS; SEMCO Energy had a dividend cut in 2002; AGL Resources, South  
9 Jersey Industries and UGI Corporation have been excluded because those companies  
10 had less than 60% of their 2005 operating revenues derived from gas distribution  
11 operations; KeySpan Corporation and Southern Union Company have been excluded  
12 because the companies are involved in merger and acquisition/divestiture activities.  
13 KeySpan Energy is in the process of being acquired by National Grid and Southern  
14 Union is in the process of divesting two of its main gas distribution subsidiaries.

15 The information for the remaining nine companies is summarized in Exhibit No.  
16 400, Schedule 5.

17 Q. Please describe Exhibit No. 400, Schedule 5.

18 A. Exhibit No. 400, Schedule 5, contains average comparative capitalization and financial  
19 statistics for the proxy group of nine VL LDCs for the years 2001 through 2005. It  
20 consists of four pages. Page 1 contains a summary of the comparative financial data for  
21 the years 2001-2005. Page 2 contains notes relevant to Page 1, as well as the selection  
22 criteria and identities of the individual companies in the proxy group. Page 3 contains the  
23 capital structure ratios based upon total capital for each company, as well as the group  
24 averages by year and company/group average for the five years. Page 4 contains

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 information as to the ability of each company in the group to protect itself against the  
2 vagaries of the weather.

3 As shown on Page 1, during the five year period ending 2005, the achieved  
4 average earnings rate on book common equity (ROE) was 11.76%. The group had a  
5 five-year average total equity ratio of 45.72% which was within the new S&P financial  
6 guidelines for an A bond rating (total equity of between 42% and 48% per guidelines on  
7 Schedule 2, page 14 of Exhibit No. 400) and an average business profile of "2.3".

8 **VIII. CAPITAL STRUCTURE**

9 Q. What capital structure ratios do you recommend for use in determining the overall cost of  
10 capital for NFGDC?

11 A. I recommend the use of ratemaking capital structure ratios consisting of 48.50% total  
12 debt and 51.50% common equity.

13 Q. Why do you recommend the use of a ratemaking capital structure consisting of 48.50%  
14 total debt and 51.50% common equity?

15 A. NFGDC's common equity ratio based on total capital at January 31, 2006 was 64.00%  
16 and is estimated to be 59.51% at January 31, 2007, the end of the future test year as  
17 shown on pages 1 and 2 of Exhibit No. 400, Schedule 6, respectively. In my opinion, a  
18 common equity ratio of nearly 60% is inappropriate to use for ratemaking because it  
19 contains a higher percentage of common equity capital than is necessary if NFGDC's  
20 capital structure were market-based, i.e., if it raised debt capital directly in the  
21 marketplace. Of course, a capital structure which contains a higher than necessary  
22 common equity ratio results in, all other things being equal, a higher revenue cost of  
23 capital which must be paid for by customers.

24 Q. Have you also considered utilizing NFG's capital structure as a proxy for NFGDC's

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 capital structure?

2 A. Yes, I considered it. Even though NFG, as discussed supra, is a diversified gas holding  
3 company and is engaged in a number of non-distribution activities, unregulated  
4 operations including exploration and production, its estimated January 31, 2007 capital  
5 structure on a consolidated basis, excluding accumulated other comprehensive income  
6 (OCI), is expected to consist of 45.84% total debt and 54.16% common equity capital as  
7 shown on Schedule 6, page 2 of Exhibit No. 400. Those ratios, I believe, would be  
8 appropriate for use in determining NFGDC's overall cost of capital, particularly in light of  
9 the fact that NFG is the sole source for all of NFGDC's external capital.

10 Q. Are the average capital structure ratios of the proxy groups of LDCs appropriate to use in  
11 establishing an overall cost of capital for NFGDC?

12 A. No. As shown on page 1 of Schedules 4 and 5 of Exhibit No. 400, the proxy group of  
13 four LDCs maintained, on average, a capital structure composed of 54.51% total debt  
14 and 45.49% equity capital (which includes 0.24% preferred stock) for the five years  
15 ending 2005; while the nine VL LDCs on average maintained a total debt ratio of 54.28%  
16 and a total equity ratio of 45.72% (including a 0.32% preferred stock ratio), respectively.  
17 As will be discussed infra and shown in Exhibit No. 400, Schedule 12, page 2, the  
18 average bond rating for the proxy groups is Moody's A2 while the S&P average for the  
19 group of four LDCs is A+ with a business profile of "1.8". The S&P average bond rating  
20 for the proxy group of nine VL LDCs is A with a business profile of "2.3". Based upon  
21 S&P's required level of total debt to total capital for a utility company with bonds rated A  
22 and an assigned business profile in the "1.8" to "2.3" (i.e., about "2") range, as can be  
23 determined from the information shown on page 14 of Exhibit No. 400, Schedule 2, the  
24 required range of total debt is 52% to 58%. Thus, the complement indicates the need for

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 maintaining total equity in the range of from 42% to 48%. The proxy groups fit into that  
2 financial guideline, i.e., that necessary to maintain an "A" bond rating based upon a  
3 business profile of approximately "2". The ratios indicated for the proxy group are not  
4 appropriate for NFGDC since I believe Distribution's business profile is significantly more  
5 risky.

6 Q. How does NFG's profile compare to the proxy group?

7 A. S&P rates NFG's debt "BBB+" and has assigned NFG a business profile of "7" under its  
8 revised guidelines of June 7, 2004. S&P divides its 10 deciles of business profile into five  
9 categories as follows: "1" and "2" well above average; "3" and "4" above average; "5" and  
10 "6" average; "7" and "8" below average; and "9" and "10" well below average. It is clear  
11 that the average business profiles of the two proxy groups of "1.8"/"2.2" place them in the  
12 well above/above average category. S&P, in its discussion of parent/subsidiary links<sup>4</sup>  
13 states:

14 Affiliation between a stronger and a weaker entity will almost always  
15 affect the credit quality of both unless the relative size of one is  
16 insignificant... A strong subsidiary owned by a weak parent generally is  
17 rated no higher than the parent. (p. 85)

18  
19 A regulated subsidiary is indeed rated higher than the parent if its stand-  
20 alone strength so warrants and regulatory protection is sufficiently  
21 strong. However, the nature of regulation has been changing and  
22 creditors can rely on regulators to a much smaller extent tha(t) (sic) in  
23 the past. As competition enters the markets, the providers are no longer  
24 monopolies and the basis of regulation is completely different. Most of  
25 all, regulators are more concerned with service quality than credit quality.

26  
27 For example, some regulated utilities are strong credits on a stand-alone  
28 basis but often are owned by companies that finance their holding in the  
29 utility with debt at the parent company, or that own other, weaker  
30 business units. To achieve a rating differential from that of the  
31 consolidated group requires evidence – based on specific regulatory  
32 circumstances – that regulators will act to protect the utility's credit  
33 profile. (p.88)

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<sup>4</sup> Standard & Poor's Corporate Ratings Criteria 2006.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

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In NFG's case its more risky (non-LDC) operations accounted for over 75% of earnings and expenditures for long-lived assets in 2005 (Source 2005 SEC Form 10-k). Thus, those non-utility operations cannot be considered insignificant.

S&P in its March 31, 2006 RatingDirect Rationale for NFG indicates that the stronger business risk profiles of the regulated units are offset by a sluggish local economy that provides minimal growth opportunities a service territory that is somewhat saturated with natural gas and a riskier exploration and production (E&P) business that is capital intensive. S&P also states that "Distribution operations in New York benefit from weather normalization, margin sharing from offsystem sales, and a multi-year rate plan." In my view, such comments accentuate the risks in its Pennsylvania operations due to the absence of beneficial ratemaking tools such as weather normalization.

In view of the foregoing, it is clear that NFGDC, on a stand-alone basis would have no better than an A minus (A-) bond rating and business profile of "5" which would require a range of total debt of 42% to 50%, implying the need for total equity in the 50% - 58% range. Even if NFGDC would be presumed to have a business profile of "4" on a stand-alone basis (i.e., above average) which would be very much higher than NFG's 7 (below average), the specified range of total debt is 45% - 52% implies the need for total equity in the 48% - 55% range. While NFG's estimated 54.16% common equity ratio at January 31, 2007 fits within that range, it is at the upper end. In order to be conservative, I adopt the midpoint of the implied range of total equity required by S&P for an A bond rating with a business profile of "4", or 51.50%.

Q. If NFGDC had its own issued debt which was rated, and was still a wholly-owned subsidiary of NFG, do you believe that its debt would be rated "BBB+" with a business profile of "7"?

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

- 1 A. No. As indicated supra, I believe that such debt would be rated better than NFG and  
2 likely would be "A-" with a business position of "5" but I conservatively assume "4" which  
3 would indicate the need to limit total debt to the 45% to 52% range which means equity  
4 would need to be in the 48.0% to 55.0% range as can be gleaned from the data on page  
5 12 of Schedule 2, Exhibit No. 400. Also, it must be kept in mind that although S&P does  
6 assign business profiles to subsidiaries, those profiles are influenced by the parent,  
7 including its unregulated operations, as discussed supra. Consequently, I believe that an  
8 assumed profile of "4" for NFGDC is conservatively reasonable in view of NFG's  
9 assigned business profile of "7" by S&P. Consequently, I conclude that an appropriate  
10 ratemaking total equity ratio for NFGDC is approximately 51.50%, the midpoint of the  
11 range required for an A bond rating with a business profile of "4".
- 12 Q. Please summarize why you believe the use of a hypothetical capital structure consisting  
13 of 48.50% total debt and 51.50% total equity is appropriate for use to determine  
14 NFGDC's overall cost of capital.
- 15 A. 1. NFGDC's estimated capital structure at January 31, 2007 contains an  
16 inappropriate percentage of common equity capital for ratemaking purposes, i.e.,  
17 59.51%.
- 18 2. Although NFG is the sole source of all of NFGDC's external capital and its  
19 estimated capital structure at January 31, 2007 includes an appropriate common  
20 equity ratio of 54.16%, it should not be the sole determinant of an appropriate  
21 ratemaking capital structure for NFGDC because it is involved in substantial  
22 unregulated business activities.
- 23 3. The proxy groups of four and nine VL LDCs have an average S&P bond rating  
24 of A+ and A and average business profiles of "1.8"/"2.3", respectively. Their five-

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 year average total equity ratios of 45.49% and 45.72% (shown on page 1 of  
2 Schedules 4 and 5 of Exhibit No. 400) fit into S&P's required financial guideline  
3 range of about 52% to 58% total debt for an A rating which implies the need for  
4 total equity in the 42% to 48.0% range.

5 4. If NFGDC had its own debt and it was rated "A-" with an assigned business  
6 profile of "5" (likely), total equity required would be in the 50% to 58% range or if  
7 assigned a business profile of "4" (less likely), the range of total equity required  
8 would be in the 48% - 55% range, as can be determined from the ranges of total  
9 debt for an A bond rating and business profiles of "5" and "4," respectively,  
10 shown on Schedule 2 , page 14 of Exhibit No. 400.

11 Q. Since you have recommended a 48.50% total debt ratio, how did you determine the  
12 relative proportions of long- and short-term debt?

13 A. In order to answer this question properly, I first needed to determine that it was proper to  
14 include short-term debt in the capital structure. In order to make that determination, I  
15 reviewed the capital structure of each company in each of the two proxy groups for the  
16 five quarters beginning with the quarter ended December 2004 through the quarter  
17 ended December 2005. The overall pattern was that short-term debt has been  
18 consistently used by every company in each proxy group for almost every single quarter.  
19 My conclusion is that it is appropriate to include a proportion of short-term debt in the  
20 capital structure. I show the details of the quarterly capital structure ratios at pages 3 and  
21 4, Schedule 6 of Exhibit No. 400 for the proxy groups of four LDCs and the nine VL  
22 LDCs, respectively. I then relied upon the average of the capital structure ratios for each  
23 proxy group for the five quarters ended December 31, 2005. I then utilized the average  
24 of those ratios as shown in Note 5 to Schedule 6, page 1 . As shown there, long-term

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 debt on average over the five quarters was 82.55% of total debt, while short-term debt  
2 represented 17.45% of total debt. Applying those percentages to the 48.50%  
3 hypothetical total debt ratio resulted in an estimated long-term debt ratio at January 31,  
4 2007 of 40.04% and a short-term debt ratio of 8.46%. I believe those ratios represent a  
5 proper balance between long- and short-term debt.

6 **IX. DEBT COST RATES**

7 Q. Please explain the basis of the debt costs associated with the long- and short-term debt  
8 ratios of 40.04% and 8.46%, respectively, which you recommend.

9 A. The long- and short-term debt cost rates at January 31, 2006 and 2007, respectively, are  
10 shown on pages 1 and 2 of Schedule 1 of Exhibit No. 400. They are as follows: 2006 -  
11 long-term debt 6.64% and short-term debt 4.35%; 2007 - long-term debt 6.64% and  
12 short-term debt 6.03%. They were provided to me by NFGDC and are sponsored by  
13 NFGDC Witness David Bauer.

14 **X. COMMON EQUITY COST RATE MODELS**

15 **A. The Efficient Market Hypothesis (EMH)**

16 Q. Are all of the models you employ market-based models?

17 A. Yes. The DCF model is market-based as current market prices are employed. The Risk  
18 Premium Model (RPM) is market-based as the current and expected bond ratings and  
19 yields reflect the market's assessment of risk. To the extent betas are used to determine  
20 equity risk premium, the market's assessment is reflected because betas are derived  
21 from regression analyses of market prices. The Capital Asset Pricing Model (CAPM)  
22 model is market-based for much the same reason as the RPM except that the yield on  
23 U.S. Government Treasury Bonds is used in lieu of company-specific bond yields. My  
24 application of the Comparable Earnings Model (CEM) is also market-based because the

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 selection process of comparable risk domestic, non-price regulated companies is based  
2 upon statistics which result from regression analyses of market prices. All of the models  
3 are, therefore, based upon the Efficient Market Hypothesis (EMH).

4 Q. Please describe the conceptual basis of the EMH.

5 A. The EMH is the cornerstone of modern investment theory. It was pioneered by Eugene  
6 F. Fama<sup>5</sup> in 1970. An efficient market is one in which security prices at all times reflect  
7 *all the relevant information at that time. An efficient market implies that prices adjust*  
8 *instantaneously to the arrival of new information and that the process therefore reflects*  
9 *the intrinsic fundamental economic value of a security.*<sup>6</sup>

10 The essential components of the EMH are:

- 11 1. Investors are rational and will invest in assets which provide the highest  
12 expected return for a particular level of risk.  
13  
14 2. Current market prices reflect all publicly available information.  
15  
16 3. Returns are independent in that today's market returns are unrelated to  
17 yesterday's returns as that information has already been processed.  
18  
19 4. The markets follow a random walk, i.e., the probability distribution of expected  
20 returns approximates the normal bell curve.  
21

22  
23 *Brealey and Myers<sup>7</sup> state:*

24  
25 *When economists say that the security market is 'efficient', they are*  
26 *not talking about whether the filing is up to date or whether desktops*  
27 *are tidy. They mean that information is widely and cheaply available*  
28 *to investors and that all relevant and ascertainable information is*  
29 *already reflected in security prices.*

30  
31 There are three forms of the EMH, namely:

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<sup>5</sup> Fama, Eugene F., "Efficient Capital Markets: A Review of Theory and Empirical Work", Journal of Finance, May 1970, 383-417.

<sup>6</sup> Morin, Roger A., "Regulatory Finance -- Utilities' Cost of Capital", Public Utilities Reports, Inc., 1994, p. 136.

<sup>7</sup> Brealey, R.A. and Myers, S.C., "Principles of Corporate Finance". McGraw-Hill Publications, Inc., 1996, 323-324.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

- 1           1.       The "weak" form asserts that all past market prices and data are fully reflected  
2           in securities prices. In other words, technical analysis cannot enable an  
3           investor to "outperform the market".  
4  
5           2.       The "semistrong" form asserts that all publicly available information is fully  
6           reflected in securities prices. In other words, fundamental analysis cannot  
7           enable an investor to "outperform the market".  
8  
9           3.       The "strong" form asserts that all information, both public and private, is fully  
10          reflected in securities prices. In other words, even insider information cannot  
11          enable an investor to "outperform the market".

12                        The "semistrong" form is generally held as true because the illegal use of insider  
13                        information can enable an investor to "beat the market" and earn excessive returns,  
14                        thereby disproving the "strong" form.  
15

16    Q.       Please explain the applicability of the EMH to your determination of common equity cost  
17               rate.

18    A.       Common sense affirms the conceptual basis of the EMH as described above. In  
19               practical terms, this means that market prices paid for securities reflect all relevant  
20               information available to investors and that no degree of sophistication and/or analysis  
21               can enable investors to outperform the market. Consequently, it confirms that all  
22               perceived risks are taken into account by investors in the prices they pay which reflect  
23               the information inexpensively or freely available such as bond ratings; analyses of the  
24               rating agencies and financial analysts, and the various methodologies employed to  
25               determine common equity cost rate, which are discussed in the academic and financial  
26               literature. Thus, in an attempt to emulate investors' actions, it is necessary to take into  
27               account the results of multiple cost of common equity models.

28    Q.       Is there specific support in the academic and financial literature for the need to rely upon  
29               multiple cost of common equity models in arriving at a recommended common equity  
30               cost rate?

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 A. Yes. For example, Phillips<sup>8</sup> states:

2 Since regulation establishes a level of authorized earnings which, in  
3 turn, implicitly influences dividends per share, estimation of the  
4 growth rate from such data is an inherently circular process. *For*  
5 *these reasons, the DCF model 'suggests a degree of precision which*  
6 *is in fact not present' and leaves 'wide room for controversy and*  
7 *argument about the level of k'.* (italics added) (p. 396)  
8

9

\* \* \*

10 *Despite the difficulty of measuring relative risk, the comparable*  
11 *earnings standard is no harder to apply than is the market-determined*  
12 *standard. The DCF method, to illustrate, requires a subjective*  
13 *determination of the growth rate the market is contemplating.*  
14 *Moreover, as Leventhal has argued: 'Unless the utility is permitted to*  
15 *earn a return comparable to that available elsewhere on similar risk, it*  
16 *will not be able in the long run to attract capital'.* (italics added) (p.  
17 398)  
18

19

20 Also, Morin<sup>9</sup> states:

21 *Sole reliance on the DCF model ignores the capital market evidence*  
22 *and financial theory formalized in the CAPM and other risk premium*  
23 *methods. The DCF model is one of many tools to be employed in*  
24 *conjunction with other methods to estimate the cost of equity. It is not*  
25 *a superior methodology that supplants other financial theory and*  
26 *market evidence. The broad usage of the DCF methodology in*  
27 *regulatory proceedings does not make it superior to other methods.*  
28 (italics added) (pp. 231-232)  
29

30 Each methodology requires the exercise of considerable judgment on  
31 the reasonableness of the assumption underlying the methodology  
32 and on the reasonableness of the proxies used to validate a theory.  
33 *The failure of the traditional infinite growth DCF model to account for*  
34 *changes in relative market valuation, discussed above, is a vivid*  
35 *example of the potential shortcomings of the DCF model when*  
36 *applied to a given company. It follows that more than one*  
37 *methodology should be employed in arriving at a judgment on the*

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<sup>8</sup> Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, 1993, Public Utility Reports, Inc., Arlington, VA, p. 396, 398.

<sup>9</sup> Roger A. Morin, Regulatory Finance – Utilities' Cost of Capital, 1994, Public Utilities Reports, Inc., Arlington, VA, pp. 231-232, 239-240.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 *cost of equity and that these methodologies should be applied across*  
2 *a series of comparable risk companies. ...Financial literature*  
3 *supports the use of multiple methods. (italics added) (p. 239)*  
4

5 Professor Eugene Brigham, a widely respected scholar and finance  
6 academician asserted:  
7

8 In practical work, it is often best to use all three methods – CAPM,  
9 bond yield plus risk premium, and DCF – and then apply judgement  
10 when the methods produce different results. People experienced in  
11 estimating capital costs recognize that both careful analysis and very  
12 fine judgements are required. It would be nice to pretend that these  
13 judgements are unnecessary and to specify an easy, precise way of  
14 determining the exact cost of equity capital. Unfortunately, this is not  
15 possible. (pp. 239-240)  
16

17 Another prominent finance scholar, Professor Stewart Myers, in his  
18 best-selling corporate finance textbook stated:  
19

20 *The constant growth formula and the capital asset pricing model are*  
21 *two different ways of getting a handle on the same problem. (italics*  
22 *added) (p. 240)*  
23

24 In an earlier article, Professor Myers explained the point more fully:

25 *Use more than one model when you can. Because estimating the*  
26 *opportunity cost of capital is difficult, only a fool throws away useful*  
27 *information. That means you should not use any one model or*  
28 *measure mechanically and exclusively. Beta is helpful as one tool in a*  
29 *kit, to be used in parallel with DCF models or other techniques for*  
30 *interpreting capital market data. (italics added) (p. 240)*  
31

32 In view of the foregoing, it is clear that investors are aware of all of the models including  
33 comparable earnings. The EMH requires the assumption that investors use them all.

34 **B. Discounted Cash Flow Model (DCF)**

35 **1. Theoretical Basis**

36 Q. What is the theoretical basis of the DCF model?

37 A. DCF theory is based upon finding the present value of an expected future stream of net  
38 cash flows during the investment holding period discounted at the cost of capital, or the

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 capitalization rate. The theory suggests that an investor buys a stock for an expected  
2 total return rate which is expected to be derived from cash flows in the form of dividends  
3 and appreciation in market price, i.e., the expected growth rate. Thus, the dividend yield  
4 on market price plus a growth rate equals the capitalization rate. The capitalization rate  
5 is the total return rate expected by investors.

6 Q. Please comment on the applicability of the DCF model in establishing the cost rate of  
7 common equity capital for NFGDC.

8 A. The DCF model has a tendency to mis-specify investors' required return rate when the  
9 market value of common stock differs significantly from its book value, as will be  
10 discussed infra in detail. Market values and book values of common stocks are seldom  
11 at unity. For example, the average market values of the proxy groups of LDC's have  
12 been well in excess of their book values as shown on page 1 of Exhibit No. 400,  
13 Schedules 4 and 5. As shown during the five years ended 2005, they range from a low  
14 171.34% to a high of 199.73%

15 A market-based DCF cost rate will result in a total annual dollar return on book  
16 common equity equal to the total annual dollar return expected by investors only when  
17 market and book values are equal since the unadjusted DCF cost rate produces the  
18 investor-expected return on the market value, application of this result to a lower book  
19 value will understate the investor-expected return when market prices substantially  
20 exceed book values. There are many macroeconomic factors which influence market  
21 values. Thus, as will be explained, regulatory allowed earnings can only influence  
22 market values but cannot control them.

23

24



National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 values diverge from book values for many reasons unrelated to allowed and/or achieved  
2 rates of earnings on book common equity (ROEs). Thus, when market values depart  
3 from book values, a market-based DCF cost rate applied to the book value of common  
4 equity will not reflect investors' expected common equity cost rate based on market  
5 prices. This is true because there are many macroeconomic factors which influence the  
6 demand for, and hence the market prices of, common stocks in addition to company-  
7 specific earnings per share (EPS) and dividends per share (DPS). Consequently, a  
8 market-based DCF cost rate applied to the book value per share will either overstate  
9 investors' required common equity cost rate when market value is less than book value  
10 or understate investors' required common equity cost rate when market value is above  
11 book value.

12 Q. Can you demonstrate how a market-based DCF cost rate will understate investors'  
13 required rate of return on book common equity when market value is above or below  
14 book value, respectively.

15 A. Yes. Schedule 7 of Exhibit No. 400 demonstrates how a significantly different book value  
16 either understates or overstates investors' required return rate on market price. It is, after  
17 all, upon the price that investors pay that they seek their desired return. This hypothetical  
18 illustration demonstrates that the expected market-based rate of return is either under-  
19 achieved or over-achieved. In the first hypothetical example, market price is 80% in  
20 excess of its book value and investors expect a total return rate of 10.00% on market  
21 price, based on a growth rate of 6.00% and a dividend yield of 4.00%. It is shown that  
22 when the 10.00% return rate is applied to the book value, which is only 55.4% of the  
23 market value, the opportunity for total annual return is only \$1.333 on book value and not  
24 \$2.40 (10.00% return on \$24 market value). With an annual dividend of \$0.96, there is

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 an opportunity to earn only \$0.373 in growth which is just 1.55% on the \$24 market price  
2 in contrast to the 6.00% growth rate in market price expected by investors. Conversely, if  
3 market value is less than book value, a market-based DCF cost rate when applied to a  
4 greater book value will result in an overstatement of investors' required rate of return  
5 related to the book value of common equity.

6 Q. Has this Commission recognized that a market-based DCF cost rate understates the  
7 common equity cost rate related to book value of common equity, especially when the  
8 divergence is great and in a volatile stock market?

9 A. Yes. It has recognized that tendency by utilizing an adjusted DCF cost rate. It did so in  
10 re: Aqua Pennsylvania Water Company (R-00038805) in its Order entered August 8,  
11 2004 and also in Pennsylvania Power & Light Company (R-00049255) in its Order  
12 entered December 22, 2004. In that Order, the PA PUC stated:

13 We find it reasonable that a financial risk adjustment, as proposed by  
14 PPL, is necessary to compensate PPL for the mismatched application of  
15 a market-based cost of common equity to a book value common equity  
16 ratio. The adjustment is necessary because the DCF method produces  
17 the investor-required return based on the current market price, not the  
18 return on the book value capitalization.

19 I will utilize the same technique in this matter.  
20

21 Q. Have other state regulatory commissions recognized the shortcomings of DCF cost rates  
22 applied to book values when market values exceed book values?

23 A. Yes. For example, the Iowa Utilities Board (IUB) recognized that tendency in its June 17,  
24 1994 Final Decision and Order in Re U.S. West Communications, Docket No. RPU-93-9  
25 the IUB stated:<sup>12</sup>

26 While the Board has relied in the past on the DCF model, in *Iowa*  
27 *Electric Light and Power Company*, Docket No. RPU-89-9, "Final

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<sup>12</sup> Re: U.S. West Communications, Inc., Docket No. RPU-93-9, 152 PUR4th at 459.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 Decision and Order" (October 15, 1990), the Board stated: "[T]he DCF  
2 model may understate the return on equity in some circumstances.  
3 This is particularly true when the market is relatively volatile and the  
4 company in question has a market-to-book ratio in excess of one."  
5 *Those conditions exist in this case and the Board will not rely on the*  
6 *DCF return. (Consumer Advocate Ex. 367, See Tr. 2208, 2250, 2277,*  
7 *2283-2284). The DCF approach underestimates the cost of equity*  
8 *needed to assure capital attraction during this time of market*  
9 *uncertainty and volatility. The board will, therefore, give preference to*  
10 *the risk premium approach. (italics added)*  
11

12 Also, the Indiana Utility Regulatory Commission (IURC) has recognized the tendency  
13 of the DCF model to understate the cost of equity when market value exceeds book  
14 value<sup>13</sup>:

15  
16 In determining a common equity cost rate, we must again recognize the  
17 tendency of the traditional DCF model, . . . to understate the cost of  
18 common equity. As the Commission stated in Indiana-Mich. Power Co.  
19 (BPU 8/24/90), Cause No. 38728, 116 PUR 4th 1, 17-18, "*the*  
20 *unadjusted DCF result is almost always well below what any informed*  
21 *financial analyst would regard as defensible, and therefore, requires an*  
22 *upward adjustment based largely on the expert witness's judgement."*  
23 *(italics added)*  
24

25 **3. Application of the DCF Model**

26 **a. Dividend Yield**

27 Q. What are the results of your applications of the DCF model?

28 A. The cost rates adjusted for financial risk obtained are 10.76% for the proxy group of four  
29 LDCs and 10.30% for the proxy group of nine VL LDCs as shown on Exhibit No. 400,  
30 Schedule 8.

31 Q. What is the basis for the average unadjusted dividend yields of 4.37% and 4.47% of the  
32 two proxy groups shown in Column No. 1 on Exhibit No. 400, Schedule 8?

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<sup>13</sup> Re: Indiana-American Water Company, Inc., Cause No. 39595, 150 PUR4th at 167-168.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 A. The dramatic volatility of the stock market confirms that spot prices should not be relied  
2 on exclusively. Conversely, reliance on too long a historical period would not be  
3 representative of the future due to an increasingly competitive environment in the natural  
4 gas industry as well as an extremely volatile stock market. Consequently, I rely on an  
5 average of recent spot prices at April 13, 2006 and average of the high and low market  
6 prices for the months of February and March 2006 as shown by company and average  
7 for each group on Exhibit No. 400, Schedule 9.

8 **b. Discrete Adjustment of Dividend Yield**

9 Q. Please explain the adjustment for discrete growth in dividends as shown in Column No. 2  
10 on Exhibit No. 400, Schedule 8.

11 A. Due to the fact that dividends are paid quarterly, or periodically, as opposed to  
12 continuously (daily), an adjustment must be made. This is often referred to as the  
13 discrete, or the Gordon Periodic, version of the DCF model.

14 Since companies tend to increase their quarterly dividend at different times of the  
15 year, a reasonable assumption is to reflect one-half the annual dividend growth rate in  
16 the  $D_1$  expression, or  $D_{1/2}$ . This is a conservative approach so as not to overstate the  
17 dividend yield as it should be representative of the next twelve-month period. Therefore,  
18 the actual average dividend yields in Column No. 1 on Exhibit No. 400, Schedule 8,  
19 have been adjusted upward to reflect one-half the rates of growth shown in Column No.  
20 4 of Exhibit No. 400, Schedule 8. The resultant adjusted dividend yields are shown in  
21 Column No. 3 of Exhibit No. 400, Schedule 8.

22 **c. DCF Growth Rates**

23 Q. Please explain the basis of the growth rates which you use in your application of the DCF  
24 model, as shown in Column No. 4 of Exhibit No. 400, Schedule 8.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 A. It is shown on Exhibit No. 400, Schedule 10 that, on average, individuals own about one-  
2 half of the common shares of the companies in both proxy groups of LDCs. Individual  
3 investors are much more likely to rely on information provided by securities analysts than  
4 more sophisticated institutional investors. They recognize that analysts' forecasts  
5 provide greater insight into prospective growth in per share value than historical  
6 accounting measures of growth. Analysts' forecasts, which incorporate historical  
7 information, are readily available from Value Line and other sources such as  
8 ThomsonFN/FirstCall, which now owns and incorporates forecasts of the Institutional  
9 Brokers Estimate System (I/B/E/S). The ThomsonFN/FirstCall estimates are readily  
10 available on the internet and which provide, in many instances, the estimates of a  
11 number of analysts. While investors are influenced by short-term earnings growth such  
12 as forecasts for the next 12 months, I believe that they are much more influenced by  
13 longer term five-year forecasts. Five years typically is the longest future period for which  
14 analysts' forecasts are available. The use of a long-term period such as five years is  
15 more consistent with the long-term investment horizon implicit in common stocks than  
16 single 12 month growth rates. EPS growth rate expectations, although they do not fully  
17 account for changes in market value, are the most significant of all accounting measures  
18 of value. It should be clear, even to the casual market observer, that the market reacts  
19 favorably when EPS expectations are met or exceeded and unfavorably when they are  
20 not.

21 In view of the foregoing, I rely upon the average projected long-term growth rate  
22 in EPS from Value Line and ThomsonFN/FirstCall as shown on page 1 of Exhibit No.  
23 400, Schedule 11 by company for each proxy group. Pages 2 through 10 of Exhibit No.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 400, Schedule 11 contain the most recent Value Line Investment Survey for the  
2 companies in the proxy groups.

3 **4. Conclusion of DCF Cost Rate**

4 Q. Please summarize your conclusion of DCF cost rates derived from your application of the  
5 DCF model to the two proxy groups of LDCs.

6 A. As discussed supra, I rely upon DCF cost rates which are adjusted for financial risk in  
7 accord with Commission precedent. They are 10.76% and 10.30% for the proxy groups  
8 of four LDCs and the nine VL LDCs, respectively. I will be discussing infra three reality  
9 checks which I have made on my ultimate recommendation of common equity cost rate.  
10 One of those checks is shown on Exhibit No. 400, Schedule 16. The information  
11 contained therein shows that the lowest allowed rate of return on common equity to an  
12 LDC during the 27 months ended March 31, 2006 was 9.45%. Accordingly, it is not  
13 reasonable to assume a common equity cost rate lower than 9.45% has any semblance  
14 to reality especially since we are in an environment of rising interest rates which have  
15 greatest impact on capital intensive public utilities. Consequently, practical DCF cost  
16 rates at 9.45% or greater produce DCF cost rates of 10.72% for the proxy group of four  
17 LDCs and 10.78% for the proxy group of nine VL LDCs as shown in Column No. 6,  
18 Schedule 8 of Exhibit No. 400. After adjustment to reflect financial risk, those cost rates  
19 increase to 12.05% and 11.98%, respectively, as shown on Line No. 5B, Schedule 1,  
20 page 3 of Exhibit No. 400.

21 **C. The Risk Premium Model (RPM)**

22 **1. Theoretical Basis**

23 Q. Please describe the theoretical basis of the RPM.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 A. The RPM is based upon the theory that the cost of common equity capital is greater than  
2 the prospective company-specific cost rate for long-term debt capital. In other words, it is  
3 the expected cost rate for long-term debt capital plus a premium to compensate common  
4 shareholders for the added risk of being unsecured and last-in-line in any claim on the  
5 corporation's assets and earnings.

6 Q. Some analysts state that the RPM is another form of the CAPM. Do you agree?

7 A. Generally yes, but there is a very significant distinction between the two models. The  
8 RPM and CAPM both add a "risk premium" to an interest rate. However, the beta  
9 approach to the determination of an equity risk premium in the RPM should not be  
10 confused with the CAPM. Beta is a measure of systematic, non-diversifiable, market risk  
11 which is usually a much smaller percentage of total investment risk, the sum of both  
12 diversifiable and non-diversifiable risks. Diversifiable, i.e., unsystematic or company-  
13 specific, risks are reflected in the RPM because the prospective company-specific long-  
14 term bond yield is the result of a bond rating process which includes an assessment of all  
15 diversifiable business and financial risks. This reality is verifiable by reading S&P's  
16 description of its bond rating process which is contained in Exhibit No. 400, Schedule 2 at  
17 pages 3 through 9. In contrast, the use of a U.S. Government Security as the risk-free  
18 rate of return in the CAPM by definition reflects no diversifiable company-specific risk.  
19 Clearly, the RPM and CAPM are two separate and distinct cost of common equity  
20 models, a fact recognized in the financial literature.

21 Q. Please describe your RPM analysis.

22 A. It is shown in Exhibit No. 400, Schedule 12, which consists of 9 pages. As can be  
23 gleaned from page 1, I have estimated the projected bond yield on Moody's A rated utility  
24 bonds to be 6.40%. As explained in Note 4 on page 1, Schedule 12 of Exhibit No. 400,

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 no adjustment is required to be made to the 6.40% yield on A rated public utility bonds to  
2 reflect the average Moody's bond rating of A2 for each proxy group of LDCs.  
3 Consequently, the resultant expected average bond yield is 6.40% applicable to each  
4 proxy group of LDCs. I then calculated the equity risk premiums applicable to each proxy  
5 group. The sum of the prospective bond yields and equity risk premiums equal the RPM-  
6 derived common equity cost rate applicable to each proxy group.

7 **2. Estimation of Expected Bond Yield**

8 Q. Please explain the basis of the expected bond yield of 6.40% applicable to the two proxy  
9 groups of LDCs.

10 A. Because the cost of common equity is prospective, the use of a prospective yield on  
11 similarly-rated long-term debt is appropriate. The average Moody's bond ratings for both  
12 proxy groups is A2 as shown on Schedule 12, page 2. I relied upon the consensus  
13 forecasts of about 50 economists of the average expected yield on Moody's Aaa rated  
14 corporate bonds for the six calendar quarters ending with the third calendar quarter of  
15 2007 as derived from the April 1, 2006 Blue Chip Financial Forecasts (shown on page 7  
16 of Exhibit No. 400, Schedule 12). As shown on Line No. 1 of page 1 of Exhibit No. 400,  
17 Schedule 12, the average expected yield on Aaa rated corporate bonds is 5.93%. It is  
18 necessary to adjust that average yield to be equivalent to the average yield on Moody's  
19 A2 rated utility bonds of the proxy groups. In order to obtain an accurate estimate of the  
20 average prospective cost of Moody's A rated public utility bonds it is necessary to add the  
21 average yield differential of Moody's A rated utility bonds over the average yield on Aaa  
22 rated corporate bonds because the Blue Chip economists no longer forecast yields on A  
23 rated public utility bonds. Consequently, I have calculated the average yield differential  
24 to be 47 basis points as shown on page 4 of Exhibit No. 400, Schedule 12. Thus, the

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 average prospective yield on Moody's A rated public utility bonds is 6.40% (5.93%  
2 average yield on Aaa corporate bonds plus 0.47% average yield spread of A rated utility  
3 bonds over Aaa corporate bonds) as shown on Line No. 3, Schedule 12, page 1 of  
4 Exhibit No. 400. Thus, the resultant expected bond yield is 6.40% applicable to both  
5 proxy groups, i.e., four LDCs and the nine VL LDCs, respectively, to which equity risk  
6 premiums must be added.

7 **3. Estimation of the Equity Risk Premiums**

8 Q. Please explain the basis of the equity risk premium which you have determined to be  
9 applicable to the each proxy group.

10 A. I evaluated the results of two different historical equity risk premium studies, as well as  
11 Value Line's forecasted total annual return on the market over the prospective yield on  
12 high grade corporate bonds. These analyses are summarized on page 5 of Exhibit No.  
13 400, Schedule 12. As shown on Line No. 3 of page 5, the resultant average equity risk  
14 premium applicable to the proxy group of four LDCs is 4.30%, while that applicable to the  
15 proxy group of nine VL LDCs is 4.22%.

16 Q. Please explain the basis of the equity risk premiums of 4.45% and 4.29% shown on Line  
17 No. 1, page 5 of Exhibit No. 400, Schedule 12, which are applicable to the two proxy  
18 groups of LDCs.

19 A. Those premiums were determined utilizing betas. Equity risk premiums determined  
20 through the application of the beta approach are meaningful because the betas were  
21 derived from regression analyses of the market prices of common stocks over a recent  
22 five-year period. The market prices reflect investors' expectations over a long-term future  
23 investment horizon. Consequently, beta is a meaningful measure of prospective risk

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 relative to the market as a whole and thus is a logical means by which to allocate a  
2 relative share of total market equity risk premium to a specific company or proxy group.

3 The average total market equity risk premium utilized was 5.23% as shown on  
4 page 6, Line No. 7 of Exhibit No. 400, Schedule 12. It is based upon an average of the  
5 long-term average historical equity risk premium of 6.20% and the forecasted market  
6 equity risk premium of 4.25% as shown on page 6, Line Nos. 3 and 6, respectively, of  
7 Exhibit No. 400, Schedule 12.

8 To derive the historical market equity risk premium, I used the most recent  
9 Ibbotson Associates' data on holding period returns for the S&P 500 Composite Index  
10 and Salomon Brothers Long-term High-grade Corporate Bond Index covering the period  
11 1926-2005. The use of holding period returns over a very long period of time is useful in  
12 the application of the beta approach. Ibbotson Associates, in its Valuation Edition -  
13 2006 Yearbook provides sound reasoning why the use of a long-term historical time  
14 period is appropriate to estimate the expected equity risk premium. They demonstrate  
15 empirically through tests of serial correlation that equity risk premiums are random. They  
16 also demonstrate and explain why the arbitrary use of shorter time periods distorts the  
17 results of estimated long-term average market equity risk premiums. Moreover, the  
18 arbitrary use of shorter time periods is contrary to the long-term randomness of equity  
19 risk premiums. Consequently, the use of a long-term arithmetic mean equity risk  
20 premium provides stability in contrast to the volatility associated with the arbitrary use of  
21 shorter historical time periods. In addition, the use of a long-term average is consistent  
22 with the long-term investment horizon implicit in the cost of common equity capital, e.g.,  
23 the premise of infinity in the standard DCF model used in public utility rate regulation.  
24 Ibbotson Associates' full explanation of why the use of the long-term average equity risk

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 premium is appropriate is provided at pages 5 through 8 of Exhibit No. 400, Schedule  
2 13.

3 In view of the foregoing and all of Ibbotson Associates' comments contained in  
4 Exhibit No. 400, Schedule 13, it is clear that the arbitrary selection of shorter historical  
5 periods would be highly suspect. Such periods would likely contain the 1987 stock  
6 market crash, the collapse of the Soviet Union, the two wars with Iraq, extraordinary  
7 inflation rates and other significant events. Therefore, the use of shorter historical time  
8 periods is unlikely to be representative of the amount of change which could occur over  
9 a long period of time in the future (the presumed long-term holding period for common  
10 stocks as is implicit in the various cost of equity models). Thus, the use of a very long  
11 past period to estimate the equity risk premium is consistent with the long-term  
12 investment horizon for utilities' common stocks. Consequently, the use of the long-term  
13 past to estimate equity risk premium is critical to proper estimation of the long-term  
14 future. The arithmetic mean of those long-term historical total return rates on the market  
15 as a whole is the appropriate mean for use in estimating the cost of capital because it  
16 provides essential insight into the potential variance of expected returns. A full  
17 explanation by Ibbotson Associates of why the arithmetic mean must be used when  
18 discounting future cash flows for estimating the cost of capital is contained in pages 2  
19 through 4 of Exhibit No. 400, Schedule 13.

20 Historical total returns and equity risk premium spreads differ in size and  
21 direction over time. It is precisely for this reason that the arithmetic mean is important.  
22 It is the arithmetic mean which provides insight into the variance and standard deviation  
23 of returns. It is the prospect for, and degree of, variance which provides the insight  
24 required by investors to estimate risk when contemplating making an investment.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1           Insight into the variance can only be obtained by the use of the arithmetic mean of  
2           historical returns. Absent valuable insight into the potential variance of returns, there  
3           can be no meaningful evaluation of prospective risk. *If investors relied upon the*  
4           *geometric mean of historical returns, they would have no insight into the potential*  
5           *variance of future returns because the geometric mean relates the change over many*  
6           *periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or*  
7           *variance, critical to risk analysis.*

8                         The basis of the historical market equity risk premium of 6.20% is detailed in Line  
9           Nos. 1 through 3, page 6 of Exhibit No. 400, Schedule 12.

10    Q.     Why do you also utilize a forecasted equity risk premium?

11    A.     In order to properly answer this question, I believe it is necessary to first explain two  
12           points with regard to the use of a long-term historical arithmetic equity risk premium.  
13           First, the long-term historical arithmetic average market equity risk premium is the most  
14           likely to be experienced over a long-term prospective period. Also, a prospective  
15           element is contained in the use of beta because *beta is derived from market prices which*  
16           *reflect expectations of the future. Secondly, beta is also utilized in conjunction with the*  
17           *prospective yield on A rated public utility bonds.*

18                         It is also appropriate to view the current potential for market price appreciation  
19           which may be possible for investors to experience in the current market environment.  
20           Such a period of up to about five years, based upon Value Line's forecasted market  
21           appreciation and dividend yield on its market universe, is something that investors would  
22           certainly be aware of, especially since about one-half of investors in the proxy LDCs are  
23           individuals, who are likely to rely upon Value Line as discussed supra. Because the  
24           potential for growth in the DCF model is market price appreciation, in estimating the

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 equity risk premium in the RPM model, it is also appropriate to take into account the  
2 forecasted equity risk premium.

3 The basis of the forecasted market equity risk premium of 4.25% is detailed in  
4 Line Nos. 4 through 6, page 6 of Exhibit No. 400, Schedule 12. The average of the  
5 historical and projected market equity risk premiums is 5.23% as shown on Line No. 7,  
6 page 6 of Exhibit No. 400, Schedule 12.

7 As shown on Line No. 9, page 6 of Exhibit No. 400, Schedule 12, application of  
8 the average beta of each proxy group (0.85 for the four LDCs and 0.82 for the nine VL  
9 LDCs) to the average market equity risk premium of 5.23% results in equity risk  
10 premiums of 4.45% and 4.29% applicable to each proxy group, respectively.

11 Q. Please describe the derivation of the equity risk premium of 4.14% on Line No. 2, page 5  
12 of Schedule 12.

13 A. For the reasons described supra by Ibbotson Associates, I caused to be performed an  
14 analysis of the long-term historical holding period returns applicable to public utilities, i.e.,  
15 the S&P Public Utility Index for the period 1928-2003, inclusive (2003 being the latest for  
16 which data comparable to all prior years is presently available from S&P). The long-term  
17 average provides a good basis for future expectations as all types of events are included,  
18 even "unusual" ones. The analysis is summarized on page 8 of Exhibit No. 400,  
19 Schedule 12. After the adjustment necessary to reflect the average equity risk premium  
20 applicable to A rated public utility bonds, the resultant adjusted equity risk premium is  
21 4.14% as indicated on Line No. 3, page 8 of Exhibit No. 400, Schedule 12.

22 Q. What are the indicated equity risk premiums applicable to each proxy group of LDCs?

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

- 1 A. They are 4.30% applicable to the proxy group of four LDCs and 4.22% applicable to the  
2 proxy group of nine VL LDCs as shown on Line No. 6, page 1 and detailed on page 5, of  
3 Exhibit No. 400, Schedule 12.
- 4 Q. Are you aware that this Commission, in the past, has rejected consideration of the use of  
5 the long-term historical equity risk premium for use in the risk premium model?
- 6 A. Yes, I am. While I disagree with the Commission on that point, in the instant matter, I  
7 have also reviewed a more contemporary period for additional insight into equity risk  
8 premium.
- 9 Q. Please describe the more contemporary period and why you chose it.
- 10 A. To avoid being totally arbitrary, I chose to focus on the period beginning with 1979.  
11 During 1979, the Federal Reserve, through its open market committee (FOMC), changed  
12 its focus to one of monetary policy, i.e., using interest rates to control the money supply  
13 and hence inflation. Thus, I have examined the period 1979 through 2005 as that policy  
14 has continued through the entire period.
- 15 Q. What historical results are derived from the 1979-2005 period?
- 16 A. As indicated in Notes 3, 4, and 5 on page 5 and Notes 7, 8 and 9 on page 6 of Schedule  
17 12 of Exhibit No. 400, the beta-derived equity risk premium is 3.52% for the four LDCs  
18 and 3.39% for the nine VL LDCs and the historical market equity risk premium applicable  
19 to utilities with A rated debt is 4.74%. When averaged, these premiums result in equity  
20 risk premiums of 4.13% for the four LDCs and 4.07% for the nine VL LDCs.
- 21 Q. Would the use of other shorter periods between 1979 and 2005 be appropriate?
- 22 A. No. The use of shorter periods would be totally arbitrary. Depending on the selected  
23 period one can derive virtually any result. It is logical to rely on all of the data from 1979  
24 on because of the change in policy by the FOMC in 1979 which since has remained

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 consistent. Even this period, 1979-2005, is really too short because just several years  
2 can greatly impact the results. After all, the investment horizon implicit in the DCF model  
3 is perpetuity, which, in practical terms, is a very long period of time.

4 **4. Conclusion of RPM Cost Rates**

5 Q. What are the resultant RPM cost rates applicable to the proxy groups?

6 A. As shown on Exhibit No. 400, Schedule 12, page 1, Line No. 7, they are 10.70% and  
7 10.62% applicable to the proxy groups of four LDCs and the nine VL LDCs, respectively.  
8 They are composed of a prospective bond yield of 6.40% and equity risk premiums of  
9 4.30% and 4.22%, respectively.

10 **5. The RPM Does Not Presume a Constant Equity Risk Premium**

11 Q. Does the RPM assume a constant equity risk premium?

12 A. No. The equity risk premium determined under the RPM varies inversely with interest  
13 rate changes since the prospective bond yield is subtracted from the estimated market  
14 return. Common sense affirms this to be so, due to common stock investors' expectation  
15 of greater returns during periods of declining interest rates and vice versa. In a sense,  
16 the equity risk premium is no different than the "g", or growth component, in the DCF  
17 model. The growth component "g" in a DCF cost rate calculated today, will invariably  
18 differ in subsequent time periods due to the availability of different growth rate data  
19 thereby confirming the reality that the "g" in the DCF model does change, even though it  
20 is presumed to be theoretically constant. In that regard, there is no difference between  
21 the RPM and DCF models, i.e., both models assume an expectationally constant equity  
22 risk premium and growth rate, respectively, but in actuality *both* change regularly.

23 As Morin<sup>14</sup> states with regard to the DCF model:

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<sup>14</sup> Id., p. 111.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 It is not necessary that  $g$  be constant year after year to make the model  
2 valid. *The growth rate may vary randomly around some average*  
3 *expected value. Random variations around trend are perfectly*  
4 *acceptable, as long as the mean expected growth is constant. The*  
5 *growth rate must be 'expectationally constant' to use formal statistical*  
6 *jargon. (italics added)*  
7  
8

9 The foregoing confirms that the RPM is similar to the DCF model in the sense  
10 that both models contain the assumption of an "expectationally constant" risk premium  
11 and growth rate, respectively, despite the fact that each varies randomly around its  
12 mean. The mean referred to is the arithmetic mean, thereby indirectly confirming that  
13 only the arithmetic mean is appropriate to use when estimating the cost of capital as  
14 discussed supra.

15 **D. The Capital Asset Pricing Model (CAPM)**

16 **1. Theoretical Basis**

17 Q. Please explain the theoretical basis of the CAPM.

18 A. The CAPM defines risk as the covariability of a security's returns with the market's  
19 returns. This covariability is measured by beta (" $\beta$ "), an index measure of an individual  
20 security's variability relative to the market. A beta less than 1.0 indicates lower variability  
21 than the market and a beta greater than 1.0 indicates greater variability than the market.

22 The CAPM assumes that all non-market, or unsystematic, risk can be eliminated  
23 through diversification. The risk that cannot be eliminated through diversification is  
24 called market, or systematic, risk. The model presumes that investors require  
25 compensation for risks that cannot be eliminated through diversification. Systematic  
26 risks are caused by socioeconomic events that affect the returns on all assets. In  
27 essence, the model is applied by adding a risk-free rate of return to a market risk

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 premium. This market risk premium is adjusted proportionally to reflect the systematic  
2 risk of the individual security relative to the market as measured by beta.

3 The traditional CAPM is expressed as:

4 
$$R_s = R_f + \beta(R_m - R_f)$$

5 Where  $R_s$  = Return rate on the common stock

6  $R_f$  = Risk-free rate of return

7  $R_m$  = Return rate on the market as a whole

8  $\beta$  = Adjusted beta (volatility of the security  
9 relative to the market as a whole)

10  
11  
12

Numerous tests of the CAPM have confirmed its validity. These tests have  
13 measured the extent to which security returns and betas are related as predicted by the  
14 CAPM.

15 The empirical CAPM (ECAPM), discussed by Morin, reflects the reality that the  
16 empirical Security Market Line (SML) described by the traditional CAPM is not as steeply  
17 sloped as the predicted SML. Morin<sup>15</sup> states:

18 At the empirical level, there have been countless tests of the CAPM to  
19 determine to what extent security returns and betas are related in the  
20 manner predicted by the CAPM.<sup>16</sup> The results of the tests support the  
21 idea that beta is related to security returns, that the risk-return tradeoff  
22 is positive, and that the relationship is linear. The contradictory finding  
23 is that the empirical Security Market Line (SML) is not as steeply sloped  
24 as the predicted SML. With few exceptions, the empirical studies agree  
25 that the implied intercept term exceeds the risk-free rate and the slope  
26 term is less than predicted by the CAPM. That is, low-beta securities  
27 earn returns somewhat higher than the CAPM would predict, and high-  
28 beta securities earn less than predicted.

---

<sup>15</sup> Id., at p. 321.

<sup>16</sup> For a summary of the empirical evidence on the CAPM, see Jensen (1972) and Ross (1978). The major empirical tests of the CAPM were published by Friend and Blume (1975), Black, Jensen, and Scholes (1972), Miller and Scholes (1972), Blume and Friend (1973), Blume and Husic (1973), Fama and Macbeth (1973), Basu (1977), Reinganum (1981B), Litzenberger and Ramaswamy (1979), Banz (1981), Gibbons (1982), Stambaugh (1982), and Shanken (1985). CAPM evidence in the Canadian context is available in Morin (1981).

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1

\* \* \*

2

Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

3

4

5

$$K = R_F + x(R_M - R_F) + (1 - X) \beta (R_M - R_F)$$

6

7

Where x is a fraction to be determined empirically. ...the value of x that best explains the observed relationship is between 0.25 and 0.30. If x = 0.25, the equation becomes:

8

9

10

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)^{17}$$

11

12

13

\* \* \* \* \*

14

The ECAPM is a return adjustment, i.e., a y-axis adjustment and thus does not increase the adjusted beta, which is an x-axis adjustment and accounts for regression bias.

15

16

17

As a result of the foregoing, I apply both versions of the model (CAPM and ECAPM) which are contained in Exhibit No. 400, Schedule 14, which consists of 4 pages.

18

19

**2. Risk-Free Rate of Return**

20

Q. Please describe your selection of a risk-free rate of return.

21

A. My applications of the CAPM and the ECAPM reflect a risk-free rate of 5.05%. It is based upon the average consensus forecast of the reporting economists in the April 1, 2006 issue of Blue Chip Financial Forecasts for the yields on 30-year U.S. Treasury Notes for the six quarters ending with the third calendar quarter 2007 as shown in Note 2 on page 4 of Exhibit No. 400, Schedule 14.

22

23

24

25

26

Q. Why is the average prospective yield on 30-year U.S. Treasury Notes appropriate for use as the risk-free rate?

27

---

<sup>17</sup> Id., at pp. 335-336.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 A. The yield on 30-year T-Notes is almost risk-free and its term is consistent with the long-  
2 term cost of capital to public utilities measured by the yields on public utility bonds and  
3 more closely matches the long-term investment horizon inherent in utilities' common  
4 stocks. Moreover, it is consistent with the long-term investment horizon, which is  
5 presumed to be infinite, in the standard DCF model employed in proceedings such as  
6 these. In addition, Ibbotson Associates<sup>18</sup> states:

7 A common choice for the nominal riskless rate is the yield on a U.S.  
8 Treasury Security. The ability of the U.S. government to create money  
9 to fulfill its debt obligations under virtually any scenario makes U.S.  
10 Treasury securities practically default-free. While interest rate changes  
11 cause government obligations to fluctuate in price, investors face  
12 essentially no default risk as to either coupon payment or return of  
13 principal. The horizon of the chosen Treasury security should match  
14 the horizon of whatever is being valued. *When valuing a business that*  
15 *is being treated as a going concern, the appropriate Treasury yield*  
16 *should be that of a long-term Treasury bond. Note that the horizon is a*  
17 *function of the investment, not the investor. If an investor plans to hold*  
18 *stock in a company for only five years, the yield on a five-year Treasury*  
19 *note would not be appropriate since the company will continue to exist*  
20 *beyond those five years. (italics added for emphasis)*  
21

22 In summary, the average expected yield on 30-year Treasury Notes is the  
23 appropriate proxy for the risk-free rate in the CAPM because it is almost risk-free and has  
24 a long-term investment horizon consistent with utilities' common stocks (not individual  
25 investors) and is thus consistent with the long-term investment horizon (which is actually  
26 assumed to be infinity) in the standard DCF model.

27 **3. Market Equity Risk Premium**

28 Q. Please explain the basis for your estimation of the expected market equity risk premium.

29 A. I estimate investors' expected total return rate which is based on an average of  
30 forecasted and long-term historical return rates from which I subtract the risk-free rate.

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<sup>18</sup> Stocks, Bonds, Bills and Inflation: 2004 Yearbook – Valuation Edition, Ibbotson Associates, Chicago, IL, p. 53.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 The result is a market equity risk premium, some proportion of which must be allocated to  
2 each proxy group. I make the allocation of the market equity risk premium through the  
3 use of beta because beta is a measure of the risk of a security relative to the entire  
4 market.

5 The basis of the projected market equity risk premium is explained in detail in  
6 Note 1 on page 4 of Exhibit No. 400, Schedule 14. The 3-5 year total market  
7 appreciation projection, when converted to an annual rate plus the market's average  
8 dividend yield equals a forecasted total annual return rate of 10.18%. The long-term  
9 historical total annual arithmetic mean return rate of 12.30% on the market is from Table  
10 2-1 of Ibbotson Associates' Stocks, Bonds, Bills and Inflation: Valuation Edition – 2006  
11 Yearbook. The relevant risk-free rate was deducted from the total market return rate.  
12 For example, from the Value Line projected total market return of 10.18%, the  
13 forecasted average risk-free rate of 5.05% was deducted indicating a forecasted market  
14 risk premium of 5.13%. From the Ibbotson Associates' arithmetic mean long-term  
15 historical total return rate of 12.30% the long-term historical income return rate on long-  
16 term U.S. Government Securities of 5.20% was deducted indicating an historical equity  
17 risk premium of 7.10%. Thus, the average of the projected and historical total market  
18 risk premiums of 5.13% and 7.10%, respectively, is 6.12%.

19 Q. Have you also reviewed the 1979-2005 period as to the historical market risk premium for  
20 use in your CAPM analysis?

21 A. Yes. I have done so for the reasons stated previously with regard to the RPM.

22 Q. What are your CAPM resultant cost rates (also using the ECAPM) when using the  
23 historical period 1979-2005?

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 A. As shown on Note 3, page 1 of Schedule 14 of Exhibit No. 400 (and compared with Note  
2 1 on page 4 of the same Schedule), the historical market risk premium decreased from  
3 7.10% (1926-2005) to 6.48% (1979-2005). The 1979-2005 historical market risk  
4 premium of 6.48%, when averaged with the forecasted market premium of 5.13%  
5 renders a market premium of 5.81% versus the 6.12% upon which I relied. As derived in  
6 Note 3, page 1 of Schedule 14, the CAPM cost rates based upon the historical period  
7 1979-2005 are 10.08% for the four LDCs and 9.94% for the nine VL LDCs.

8 **4. Conclusion of CAPM Cost Rates**

9 Q. What are the results of your applications of the CAPM and ECAPM?

10 A. They are shown on Exhibit No. 400, Schedule 14, page 1.

11 The average traditional CAPM cost rates are 10.25% and 10.05%, while the  
12 average ECAPM cost rates are 10.48% and 10.33% for the proxy groups of four and nine  
13 VL LDCs, respectively. I rely upon the average of both the CAPM and ECAPM cost  
14 rates. They are 10.37% and 10.19% for the proxy groups of four and nine VL LDCs,  
15 respectively, as shown on Line No. 3, page 1 of Exhibit No. 400, Schedule 14. For the  
16 reasons discussed supra with regard to the results of the practical DCF cost rates, only  
17 two traditional CAPM results were eliminated from consideration, i.e., the 9.33% for  
18 Atmos Energy and Northwest Natural Gas because they were less than 9.45%, the  
19 lowest allowed ROE to an LDC by any regulatory commission during the 27 months  
20 ended March 31, 2006. The resultant practical CAPM cost rates are 10.52% and 10.29%  
21 for the proxy groups of four LDCs and the nine VL LDCs, respectively.

22 **E. The Comparable Earnings Model (CEM)**

23 **1. Theoretical Basis**

24 Q. Please describe the theoretical basis of the CEM.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 A. The comparable earnings standard recognizes the fundamental economic concept of  
2 opportunity cost. This concept states that the cost of using any resource – land, labor  
3 and/or capital – for a specific purpose is the return that could have been earned in the  
4 next best alternative use. *The opportunity cost to an investor in a utility's common stock*  
5 *is what that capital would yield in an alternative investment of similar risk. The*  
6 *opportunity cost principle is consistent with one of the fundamental principles of utility*  
7 *price regulation, i.e., it is intended to act as a surrogate for the competition of the*  
8 *marketplace.*

9 The problem in using returns on book equity (the ROEs) of non-price regulated  
10 companies is determining whether such companies are similar in risk to the price-  
11 regulated utility. *The ROEs of other similar price-regulated firms should not be relied*  
12 *upon because they reflect the results of regulatory awards which may not be indicative of*  
13 *what could have been earned in a competitive market. Moreover, to use such returns as*  
14 *a primary method to establish a cost of equity would be an exercise in circularity.*  
15 *Consequently, application of the CEM is most appropriately implemented by examining*  
16 *the ROEs of similar risk, domestic, non-price regulated firms.*

17 In a more competitive environment for energy utilities, the concept of observing  
18 the rates of earnings on book equity, or net worth, of comparable non-price regulated  
19 firms has greater relevance than ever despite a long regulatory history for the use of the  
20 comparable earnings method. Moreover, the use of ROEs of comparable non-price  
21 regulated firms is appropriate because:

22 (1) Under the rate base/rate of return paradigm, the rate of return (including  
23 the rate of return on common equity) is applied to a rate base measured  
24 at original (i.e., book) cost;

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1                   (2)    As discussed supra, many socioeconomic factors influence market  
2   prices other than company-specific EPS and/or DPS. Thus, when  
3   market values differ from their book values, market-based DCF cost  
4   rates either understate or overstate the rates of earnings required on  
5   book equity (i.e., the common equity financed portion of an original cost  
6   rate base); and

7                   (3)    As also discussed supra, regulatory decisions can influence, but cannot  
8   control market prices.

9   **2. Application of the CEM**

10    Q.     How did you approach your CEM analysis?

11    A.     My CEM analysis is set forth in Exhibit No. 400, Schedule 15, which consists of four  
12   pages. Pages 1 and 2 contain the relevant data for the domestic non-price regulated  
13   companies which are comparable in risk to my proxy groups of LDCs. Pages 3 and 4  
14   contain the notes relative to pages 1 and 2.

15   It is critical to the application of the CEM to select proxy groups of non-price  
16   regulated companies which are similar in total risk to the price-regulated proxy groups of  
17   LDCs. The proxy groups of comparable non-price regulated firms should be broad-  
18   based in order to obviate individual company-specific aberrations. Utilities should be  
19   eliminated to avoid circularity since the rates of return on their book common equity are  
20   substantially influenced by the rate determinations of their respective regulatory  
21   commissions, many of which are the result of negotiated settlements and are not truly  
22   market-based cost rates.

23   **3. Selection of Market-Based Companies of Similar Risk**

24    Q.     Is your application of the CEM market-based?

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 A. Yes. My application of the CEM is market-based because the selection of the  
2 comparable non-price regulated firms is based upon statistics derived *from the market*  
3 *prices paid by investors*. Specifically, I rely upon the betas and related statistics derived  
4 from Value Line regression analyses of weekly market prices over the most recent 260  
5 weeks (five years). The bases of selection resulted in two proxy groups of non-price  
6 regulated firms comparable to the price-regulated proxy groups of four LDCs and nine VL  
7 LDCs, respectively. The average company in each proxy group of non-price regulated  
8 companies is comparable to the average company in each proxy group of LDCs. Total  
9 risk is the sum of non-diversifiable market risk and diversifiable company-specific risks.  
10 The criteria used in the selection of the non-price regulated firms were:

- 11 1. They must be covered by Value Line Investment Survey (Standard Edition).
- 12 2. They must be domestic, non-price regulated companies, i.e., non-utilities.
- 13 3. Their betas must lie within plus or minus two standard deviations of the average  
14 unadjusted beta of each proxy group of LDCs.
- 15 4. The residual standard errors of the regressions must lie within plus or minus two  
16 standard deviations of the average residual standard error of the regression for  
17 each proxy group of LDCs.

18 Betas are a measure of market, or systematic, risk. The standard errors of the  
19 regressions were used to measure each firm's company-specific risk (diversifiable,  
20 unsystematic risk). The standard errors of the regressions measure the extent to which  
21 events specific to a company affect its stock price. *Because market prices reflect*  
22 *investors' perceptions of total risk, all risk which is not systematic market risk (beta) is*  
23 *reflected in the standard error of the regression which is a measure of total non-*  
24 *systematic risk which is diversifiable. In essence, companies which have similar betas*

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1           *and similar standard errors of the regressions have similar total investment risk.* The  
2           betas and standard errors result from regression analyses of market prices which reflect  
3           all perceived risks consistent with the EMH. Consequently, the use of those regression  
4           statistics results in proxy groups of non-price regulated domestic firms which are similar  
5           in total investment risk to each proxy group of LDCs. The use of two standard deviations  
6           captures 95.50% of the distribution of unadjusted betas and standard errors thereby  
7           assuring comparability of total risk.

8           Q.     Please discuss the projected ROEs of the 64 domestic, non-price regulated companies  
9           shown on page 1 and 36 companies shown on page 2 of Exhibit No. 400, Schedule 15.

10          A.     After assuring comparability through the use of betas and standard errors as discussed  
11           supra, I reviewed Value Line's five-year projected ROEs for the companies in each group  
12           and performed a test (Student's T-Statistic) to assure that I would not rely upon any  
13           ROE(s) that were statistical outliers. As a result, three observations in each group were  
14           found to be statistical outliers.

15                     I also decided to eliminate from each group all those projected ROEs of 20.0%  
16           or higher and those below 9.45%.

17                     The mean ROEs excluding those determined to be statistical outliers per the T-  
18           tests are 14.87% and 14.24% based upon the non-price regulated proxy groups  
19           comparable to the proxy groups of four LDCs and the nine VL LDCs, respectively.

20                     I rely, however, on the average ROEs of 14.56% and 14.48% for each group  
21           after eliminating ROEs 20.0% or higher and those below 9.90%. I eliminated those  
22           20.0% or higher because it is unlikely that any gas distribution utility would be awarded  
23           an opportunity to earn such returns on equity. Conversely, I also eliminated ROEs below  
24           9.45% because 9.45% is the lowest awarded ROE to an LDC by any state commission

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 during the period January 1, 2004 through March 31, 2006 especially since it is clear that  
2 prospectively, interest rates and hence the cost of equity will continue to increase,  
3 especially for capital intensive public utilities. In eliminating all ROEs of 20.00% or higher  
4 and those below 9.45%, I also automatically eliminated all of the statistical outliers  
5 discussed supra.

6 **4. Conclusion of CEM Cost Rate**

7 Q. What are the most indicative CEM cost rates applicable to the proxy groups of four LDCs  
8 and nine VL LDCs?

9 A. As shown on page 1 of Exhibit No. 400, Schedule 15 and in accordance with the  
10 discussion supra, the average Value Line five-year projected ROEs, after exclusion of  
11 those 20.0% or higher and less than 9.45%, are 14.56% applicable to the proxy group of  
12 four LDCs, and (as shown on page 1 of Schedule 15) and 14.48% applicable to the proxy  
13 group of nine VL LDCs (as shown on page 2 of Schedule 15).

14 **XI. CONCLUSION OF COMMON EQUITY COST RATE**

15 **A. Conclusion of Common Equity Cost Rate**  
16 **Must be Based on the Application of Multiple Models**  
17

18 Q. Please summarize why, in your opinion, the conclusion of common equity cost rate must  
19 be based upon the results of the application of multiple cost of common equity models.

20 A. As discussed supra, the EMH and common sense mandate the use of multiple market-  
21 based cost of common equity models. All of the models which I have utilized are market-  
22 based.

23 1. The DCF Model utilizes market prices paid by investors.

24 2. The RPM utilizes the expected market yield on company-specific long-term debt  
25 and the equity risk premium based upon an expectation of the market equity risk  
26 premium.  
27

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1           3.       The CAPM and ECAPM utilize total market returns, and betas which result from  
2                   each individual stock's market price movement relative to the market.

3  
4           4.       The CEM is based upon the selection of comparable risk, non-price regulated  
5                   *domestic companies selected through the use of statistics derived from*  
6                   *regression analyses of market prices paid by investors.*

7  
8           Investors are aware of all of these cost of common equity models which are in use and  
9                   discussed in the financial literature. Therefore, belief in the EMH requires that all of them  
10                  be taken into account.

11   Q.       What is your recommended range of common equity cost rate applicable to NFGDC?

12   A.       It is 12.00%-12.25% applicable to NFGDC and it is derived from the application of all four  
13                  cost of common equity models to the two proxy groups of LDCs. Those proxies are less  
14                  risky than NFGDC and had an average cost rate range of 11.40%-11.60% as shown on  
15                  Line No. 6, page 3 of Schedule 1 of Exhibit No. 400. Thus, that range of cost rate needs  
16                  to be adjusted upwards as to be reflective of NFGDC's grater risk attributable to its small  
17                  size and lack of protection from the vagaries of the weather vis-à-vis the proxy groups.  
18                  Two adjustments are necessary. Those adjustments are shown on Line Nos. 7A and 7B  
19                  of Schedule 1, page 3. The first adjustment, a range of from 0.30%-0.60% (explained in  
20                  Note 6 on page 6 of the same Schedule 1) is necessary in order to reflect NFGDC's  
21                  considerably smaller size vis-à-vis the average size of each proxy group. The small size  
22                  adjustment is detailed and quantified in pages 10-12 of Schedule 1. As discussed supra,  
23                  NFGDC's smaller size actually indicates an increase in the cost of common equity of  
24                  1.88% based upon the two proxy groups; however, in order to be conservative and yet  
25                  still recognize NFGDC's small size (based upon its jurisdictional rate base upon which a  
26                  fair rate of return will be applied including the common equity financed portion thereof), I  
27                  have only provided for a range of upward adjustment of from 30 to 60 basis points based

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1           upon the proxy groups, roughly only one-sixth to one-third of the magnitude of the  
2           adjustment indicated, i.e., 1.88% or 188 basis points.

3                       In addition, as explained in Note 7 on page 6 of Schedule 1, 50% of the proxy  
4           group of four LDCs have protection against the vagaries of weather, while 66.7%, or six  
5           of the nine Value Line LDCs have such protection. NFGDC in Pennsylvania has no  
6           protection against the impact of the vagaries of weather on revenues, earnings and cash  
7           flows. Thus, the Pennsylvania jurisdictional rate base is exposed to greater risk than the  
8           proxy groups. The lack of protection from the vagaries of the weather increase the  
9           potential for greater volatility of earnings and cash flows vis-à-vis the proxy groups and  
10          thus equals greater risk. The adjustments on Line 7B of Schedule 1, page 3 of 0.13%  
11          and 0.17% reflect the average of the upward adjustments of each proxy group as  
12          explained in detail in Note 7, page 6 of Schedule 1. I believe that to have such  
13          protection, such as a weather normalization adjustment clause, reduces common equity  
14          cost rate risk by 0.25%. Conversely, because NFGDC does not have such a clause in  
15          place in the Pennsylvania jurisdiction, the cost rates of the proxy groups must be  
16          adjusted upward on a pro rata basis to reflect NFGDC's greater common equity risk.

17                       Thus, the range of 11.40%-11.60% of common equity cost rate applicable to the  
18          two proxy groups plus the two upward risk adjustments (0.30%-0.60% for small size) and  
19          (0.13%-0.17% for lack of protection from the vagaries of the weather), as discussed  
20          supra and summarized on Line Nos. 7A and 7B on Schedule 1, page 3, results in a range  
21          of common equity cost rate of from 11.87%-12.33% as shown on Line No. 8. I believe a  
22          range of from 12.00%-12.25% is appropriate.

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

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**XII. REALITY CHECKS**

Q. Have you performed any reality checks to affirm that your recommended common equity cost rate range of 12.00%-12.25% is reasonable?

A. Yes, I have. There are three checks. The first is recognition given by the Commission in its Order dated July 23, 2004 re Aqua Pennsylvania, Inc., in R-00038805 et al, where they stated at page 62:

*In Lower Paxton Township v. Pennsylvania Public Utility Commission, 317 A.2d 917 (Pa. Cmwlth. Ct. 1974) (Lower Paxton Township), the Court recognized that the Commission may consider factors which affect the cost of capital, such as the utility's financial structure, credit standing, dividends, risks, regulatory lag, wasting assets and any peculiar features of the utility involved. Here, as in PAWC, we are guided by the spirit and intent of Lower Paxton.*

The ALJ recommended a 10.0% cost of equity, relying too heavily on the DCF methodology. However, the ALJ failed to sufficiently consider the other standard financial models, including Comparable Earnings, the Risk Premium Model, and the CAPM, as checks upon the reasonableness of the DCF results. *See generally, PA P.U.C. v. Pennsylvania Suburban Water Company, 219 PUR 4<sup>th</sup> 272 (2002). (italics in original)*

I have consistently maintained that the EMH requires consideration of all the models, i.e., specifically those mentioned by the Commission supra.

The second check, shown on Schedule 16 of Exhibit No. 400 is a summary of regulatory awards made to gas distribution companies during the period January 1, 2004 through March 31, 2006. As shown, the average authorized rate of return on common equity (ROE) was 10.67% relative to an average common equity ratio of 47.30% in litigated cases. Capital costs have already begun to rise and are expected to continue to rise during any reasonable period of time that new rates resulting from this proceeding would be in effect. For example, reference to the consensus forecasts of April 1, 2006

National Fuel Gas Distribution Corporation  
Direct Testimony of Frank J. Hanley

1 from Blue Chip Financial Forecasts (Schedule 12, page 7 of Exhibit No. 400) the average  
2 yield on Aaa corporate bonds is expected to increase by 50 basis points between early  
3 2006 and the second quarter 2007. When the average 10.67% allowed return on equity  
4 is adjusted to reflect the projected increase in the Aaa corporate bond rate plus the  
5 clearly yet unreflected impact on the forecasts of new Fed Chairman Bernanke's  
6 pronouncements about the strength of the economy, and the likely impact on capital  
7 costs as well as NFGDC's unique risks (small size and lack of protection from the  
8 vagaries of weather), my recommendation appears to be reasonable.

9 The third check is the practical DCF results based on the proxy groups adjusted  
10 to eliminate those rates less than 9.45% for the reasoning discussed supra. After those  
11 adjustments are made, the DCF cost rates are 10.72% and 10.78% for the proxy groups  
12 of four LDCs and nine VL LDCs, respectively. When those cost rates are adjusted to  
13 reflect the financial risk difference between market and book value ratios, the adjusted  
14 DCF cost rates are 11.98% and 12.05%, respectively, based on the two proxy groups.  
15 An average DCF cost rate of 12.02% adjusted for financial risk based on the two proxy  
16 groups plus just 0.30% for size, 0.15% (0.13% + 0.17%) for lack of protection from the  
17 vagaries of the weather indicates a 12.47% common equity cost rate which would be  
18 applicable to NFGDC. When NFGDC's more risky likely business profile of "4" or "5" is  
19 considered vis-à-vis the proxy groups' average profile of "1.8" and "2.3", I believe my  
20 recommendation is reasonable.

21 Q. Does that conclude your direct testimony?

22 A. Yes, it does.

APPENDIX A

PROFESSIONAL QUALIFICATIONS

OF

FRANK J. HANLEY, CRRA  
PRESIDENT

AUS CONSULTANTS - UTILITY SERVICES

## PROFESSIONAL QUALIFICATIONS OF FRANK J. HANLEY

### EDUCATIONAL BACKGROUND

I am a graduate of Drexel University where I received a Bachelor of Science Degree from the College of Business Administration. The principal courses required for this Degree include accounting, economics, finance and other related courses. I am also Certified by the Society of Utility and Regulatory Financial Analysts, formerly the National Society of Rate of Return Analysts, as a Rate of Return Analyst (CRRA).

### PROFESSIONAL EXPERIENCE

In 1959, I was employed by American Water Works Service Company, Inc., which is a wholly-owned subsidiary of American Water Works Company, Inc., the largest investor-owned water works operation in the United States. I was assigned to its Treasury Department in Philadelphia until 1961. During that period of time, I was heavily involved in the development of cash flow projections and negotiations with banks for the establishment of lines of credit for all of the operating and subholding companies in the system, which normally aggregated more than \$100 million per year.

In 1961, I was assigned to its Accounting Department where I remained until 1963. During that two-year period, I became intimately familiar with all aspects of a service company accounting system, the nature of the services performed, and the methods of allocating costs. In 1963, I was reassigned to its Treasury Department as a Financial Analyst. My duties consisted of those previously performed, as well as the expanded responsibilities of assisting in the preparation of testimony and exhibits to be presented to various public utility commissions in regard to fair rate of return and other financial matters. I also designed and recommended financing programs for many of American's operating subsidiaries and negotiated sales of long-term debt securities and preferred stock on their behalf either directly with institutional investors or through investment bankers. I was elected Assistant Treasurer of a number of operating subsidiaries in the Fall of 1967, just prior to accepting employment with the Communications and Technical Services Division of the Philco-Ford Corporation located in Fort Washington, Pennsylvania. While in the employ of the Philco-Ford organization, as a Senior Financial Analyst, I had responsibility for

the pricing negotiations and analysis of acceptable rates of return to the corporation for all types of contract proposals with various agencies of the U.S. Government and foreign governments.

In the Summer of 1969, I accepted a position with the Financial Division of The Philadelphia National Bank. I was elected Financial Planning Officer of the bank in December 1970. While employed with The Philadelphia National Bank, my responsibilities included preparation of the annual and five-year profit plans. In the compilation of these plans, I had to perform detailed analyses and measure the various levels of profitability for each organizational unit. I also assisted correspondent banks in matters of recapitalization and merger, made recommendations and studies for their use before the various regulatory bodies having jurisdiction over them.

In September 1971, I joined AUS Consultants - Utility Services Group as Vice President. I was elected Senior Vice President in May 1975. I was elected President in September 1989.

#### EXPERT WITNESS QUALIFICATIONS

I have offered testimony as an expert witness on the subjects of fair rate of return and utility financial matters in more than 300 various cases and dockets before the following agencies and courts: before the Alaska Public Utilities Commission and its successor the Regulatory Commission of Alaska, the Arizona Corporation Commission, the Arkansas Public Service Commission, the California Public Utilities Commission, the Public Utilities Control Authority of Connecticut, the Delaware Public Service Commission, the Florida Public Service Commission, Hawaii Public Utilities Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Public Utility Regulatory Commission, the Iowa Utilities Board, the Public Service Commission of Kentucky, the Maryland Public Service Commission, the Massachusetts Department of Public Utilities, the Michigan Public Service Commission, the Minnesota Public Utilities Commission, the Missouri Public Service Commission, the Public Utilities Commission of Nevada, the New Jersey Board of Public Utilities, the New Mexico State Corporation Commission, the Public Service Commission of the State of New York, the North Carolina Utilities Commission, the Ohio Public Utilities Commission, the Oklahoma Corporation Commission, the Pennsylvania Public Utility Commission, the Rhode Island Public Utilities Commission, the Tennessee

Public Service Commission, the Public Service Board of the State of Vermont, the Virginia State Corporation Commission, the Public Services Commission of the Territory of the U.S. Virgin Islands, the Washington Utilities and Transportation Commission, the Public Service Commission of West Virginia, the Wisconsin Public Service Commission, the Federal Power Commission and its successor the Federal Energy Regulatory Commission. I have testified before the New Jersey Division of Tax Appeals and the United States Bankruptcy Court - Middle District of Pennsylvania with regard to the economic valuation of utility property. Also, I have testified before the U.S. Tax Court in Washington D.C. as an expert witness on the value of closely held utility common stock in a contested Federal Estate Tax case.

In addition, I have appeared as a Staff rate of return witness for the Arizona Corporation Commission, the Delaware Public Service Commission and the Virgin Islands Public Services Commission. I have testified on the fair rate of return on behalf of the City of New Orleans, Louisiana, and also acted as project manager for my firm in representing the City in the 1980-1981 rate proceeding of New Orleans Public Services, Inc. The City of New Orleans then had, as it does now, regulatory authority with regard to the retail rates charged by New Orleans Public Service, Inc., for electric and natural gas service. I have also acted as a consultant to the District of Columbia Public Service Commission itself -- not in the capacity of Staff.

I have testified before a number of local and county regulatory bodies in various states on the subject of fair rate of return on behalf of cable television companies as well as before an arbitration panel in Ohio and a State District Court in Texas. I have testified before the Public Works Committee of the Nebraska State Senate in relation to Legislative Bill 731 which proposed permitting Public Power Districts and Municipalities to enter the Cable Television field.

PROFESSIONAL ASSOCIATIONS,  
PUBLICATIONS AND GUEST SPEAKER APPEARANCES

I am a Member of the Society of Utility and Regulatory Financial Analysts (SURFA), formerly known as the National Society of Rate of Return Analysts. I am a Certified Rate of Return Analyst (CRRRA). I am on the Advisory Council of New Mexico State University's Center for Public Utilities which is endorsed by the National Association of Regulatory Utility Commissioners (NARUC). I am also a

member of the Executive Advisory Council of the Rutgers University School of Business at Camden. AUS Consultants – Utility Services is an associate member of the American Gas Association (AGA) and I am a member of AGA's Rate and Strategic Issues Committee. I am also an associate member of the National Association of Water Companies and the Energy Association of Pennsylvania. AUS Consultants – Utility Services is an associate member of the New Jersey Utilities Association.

I often attend SURFA meetings during which considerable information on the subject of rate of return is exchanged. I have also attended corporate bond rating seminars held by Standard & Poor's Corporation. I continuously review financial publications of institutions such as Standard & Poor's, Moody's Investors' Service, Value Line Investment Survey, and periodicals of various agencies of the U.S. Government.

I co-authored an article with A. Gerald Harris entitled "Does Diversification Increase the Cost of Equity Capital?" which was published in the July 15, 1991 issue of Public Utilities Fortnightly. Also, an article which I co-authored with Pauline M. Ahern entitled "Comparable Earnings: New Life for an Old Precept" was published in the American Gas Association's Financial Quarterly Review, Summer 1994. I also authored an article entitled "Why Performance-Based Incentives Are Essential" which was published in THE CITY GATE, Fall 1995, a magazine published by the Pennsylvania Gas Association.

I have appeared as a guest speaker before an annual convention of the Mid-American Cable Television Association in Kansas City, Missouri and as a guest panelist on the small water companies' operation seminar of the National Association of Water Companies' 77th Annual Convention in Hollywood, Florida. I addressed the Second Annual Seminar on Regulation of Water Utilities sponsored by N.A.R.U.C., at the University of South Florida's St. Petersburg campus. I have spoken on fair rate of return to the Third and Fourth Annual Utilities Conferences, as well as the special conference on the cost of capital in El Paso, Texas sponsored by New Mexico State University. In 1983 I also made a presentation on the Cost of Capital in Atlantic City, New Jersey, at a seminar co-sponsored by Temple University. I have also addressed the Public Utility Law Section of the American Bar Association's Third Institute on Fundamentals of Ratemaking which was held in Washington, D.C. and I addressed a

Conference on Cable Television sponsored by The University of Texas School of Law at Austin, Texas. Also, I addressed a meeting of the New England Water Works Association at Boxborough, Massachusetts, on the subject of Enterprise Financing. In addition, I was a speaker and mock witness in three different Utility Workshops for Attorneys sponsored by the Financial Accounting Institute held in Boston and Washington, D.C. I also was on a panel at the 23rd Financial Forum sponsored by the National Society of Rate of Return Analysts. The topic was Rate of Return Determination in the Diversified and/or Partially Deregulated Environment. I addressed the 83rd Annual Meeting of the Pennsylvania Gas Association in Hershey, PA. My topic was the Cost of Capital Implications of Demand Side Management. In June 1993, I lectured on the cost of capital at the American Gas Association's Gas Rate Fundamentals Course. In October 1993, I was a guest speaker at the University of Wisconsin's Center for Public Utilities -- my topic was "Diversification and Corporate Restructuring in the Electric Utility Industry - Trends and Cost of Capital Implications." In October 1994, I was a guest speaker on a panel at the Fourteenth Annual Electric & Natural Gas Conference in Atlanta, Ga., sponsored by the Bonbright Utilities Center of the University of Georgia and the Georgia Public Service Commission. The panel topic was "Responses to Competition and Incentive Rates." In October 1994, I was a guest speaker on a panel at a conference and workshop called "Navigating the Shoals of Cable Rate Regulation" sponsored by EXNET in Washington, D.C. The panel topic was "Rate of Return." Also, in March 1995, I was a guest speaker on a panel at a conference entitled, "Current Issues Challenging the Regulatory Process" sponsored by New Mexico State University - Center for Public Utilities. My panel topic concerned the electric industry and was titled, "Impact of a Competitive Structure on the Financial Markets". In May 1995, I was a guest speaker at the 87th Annual Meeting of the Pennsylvania Gas Association in Hershey, PA. My topic was "The Pennsylvania Economy and Utility Regulation: Impact on Industry, Consumers and Investors." In May 1996, I was on a panel at the 28th Financial Forum of the Society of Utility and Regulatory Financial Analysts. The panel's topic was "Revisiting the Risk Premium Approach" and was held in Richmond, Virginia. Since May 1996, I have participated as an instructor in 2-3 seminars per year on the "Basics of Regulation" (and the ratemaking process in a changing environment) and also in a

program called "A Step Beyond the Basics", all sponsored by New Mexico State University's Center for Public Utilities and NARUC. In March 2002, I was a guest speaker before the Rate and Strategic Issues Committee of the American Gas Association in St. Petersburg, Florida. My topic was Rate of Return Strategies. In December 2002, I was a guest speaker at a seminar entitled, "Service Innovations and Revenue Enhancements for the Energy Distribution Business" sponsored by the American Gas Association in Washington, DC. My topic was "The Impact of Volatile Energy Markets on Rate of Return Strategies". In February 2003, I spoke at the Rutgers University-Camden, NJ M.B.A. Speaker Series. I addressed M.B.A. students and interested faculty on the role of the expert witness in the public utility ratemaking process. In November 2003 and 2004, by invitation, I was a Guest Professor at Rutgers University – Camden for classes of undergraduate finance students, and managerial accounting students, respectively.