National Fuel Gas Distribution Corporation
Direct Testimony of Eric H. Meinl

Q. State your name and business address.

A. My name is Eric H. Meinl. My business address is 6363 Main St, Williamsville, New York 14221.

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

A. I am employed by National Fuel Gas Distribution Corporation ("Distribution" or "Company") as General Manager in Distribution's Rates and Regulatory Affairs Department.

Q. Describe briefly your educational background and experience.

A. In 1981, I graduated from the State University of New York at Buffalo, New York with my Bachelor of Business Management degree and with a concentration in Finance. In 1984, I received my Master of Business Administration degree from the State University of New York at Buffalo, and began my employment with Distribution as a Management Trainee. Later in 1984, I was promoted to the position of Supervisor. In 1988 I was promoted to the position of Assistant Manager, and in 1990 I was promoted to Director in Distribution's Market Planning and Analysis Department. In June of 1992, I was transferred to the Contract Administration Department and in August of 1994 I was promoted to the position of Manager of Regulatory Affairs. In January of 1995 I was transferred to Distribution's Market Planning Department, in August 1996 I was promoted to Senior Manager of the Market Planning Department. In September of 1998 I was promoted to Assistant

General Manager of the Rates and Regulatory Affairs Department, and in March of 2002 to General Manager.

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

A. Yes. I testified before this Commission on behalf of Distribution in Docket Nos. R-870719, R-891218, R-901670, R-911912, R-922499, R-932548, R-932885, R-943207, R-953487, R-963779, R-974167, R-984497,R-994785, R-994898, R-005832, and R-038168.

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

A. Yes. In addition to the expert testimony I have presented to this Commission, I have presented testimony before the New York Public Service Commission and the Federal Energy Regulatory Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the reasons for the changes in rate structure and cost recovery mechanisms proposed by the Company in this case. I will also provide testimony regarding the choice of the absolute level of return on equity ("ROE"), chosen from the reasonable range of ROEs presented in Mr. Hanley's testimony, which was used by the Company to calculate its revenue requirement.

Q. Please provide a general description of the changes being proposed by the Company in this proceeding.

A. The Company is proposing a number of major changes to its service offerings to customers, including:

(1) An enhanced energy efficiency ("EEE") program.

(2) Significant rate design and rate structure changes.

(3) Initiatives to further competition for Natural Gas Supply ("NGS") service including:

a. More comprehensive delivery rate unbundling

b. Purchase of marketers receivables program

Q. Why is the Company proposing these changes?

A. These proposals are being made in response to the dramatic changes in the energy market place experienced in the past year and its impact on the Company, its customers, and its service territory in general.

Particularly, the effects of Hurricanes Katrina and Rita have added a new level of uncertainty and volatility in the natural gas market. Exhibit 19, Schedule 1, provides a graphical summary of the impact of the hurricanes on winter prices.

Exhibit 19, Schedule 1, is a graph providing trading activity for natural gas future contracts on the New York Mercantile Exchange ("NYMEX") for near month winter natural gas deliveries. By near month winter natural gas deliveries I mean the trading prices for the winter months of December, January, February, and March. Exhibit 19, Schedule 1 provides the high, low, and closing price for each near winter month traded during the month. For

example, the graph provides pricing information during the trading month of October 2004 (the top left hand corner of the graph identifies the trading month of October 2004) for natural gas delivery prices for the months of December 2004, January 2005, February 2005, and March 2005. Moving along the top of the graph to the trading month of December 2004, the graph identifies the closing price for the December 2004 contract which completed trading a the end of November 2004 with the letter C, as well as identifying the high, low, and closing trading prices for the delivery months of January 2005, February 2005, and March 2005. As can be seen from the graph, the effects of hurricanes Katrina and Rita experienced during August and September 2005 had a material impact not only on the closing prices for natural gas, but also on the volatility of natural gas prices as measured by the high and low trading ranges identified for each month.

It is likely that future natural gas prices will continue to exhibit this volatility depending on such market driving events as the overall level of demand for natural gas, the supply of natural gas, experienced colder or warmer than normal weather, and the severity of hurricane seasons.

In addition to the changes in the natural gas market, the changes in services proposed by the Company are also more consistent with the criteria of a sound rate structure, as promulgated by James C. Bonbright, et al. in the Principles of Utility Rates, Second Edition, summarized in Exhibit 19, Schedule 2.

Q. Could you provide a general description of the Company's Pennsylvania service territory?

A. Yes. The Company serves customers in 14 Northwestern Pennsylvania counties. The following discussion will provide a general description of the Company's Pennsylvania service territory and compare the counties in its service territory with the state of Pennsylvania and the Mid-Atlantic and East North Central Census Division. The Mid-Atlantic Census Division ("MACD") was chosen to be included in this comparison because it includes the state of Pennsylvania. In addition to Pennsylvania, New York state and New Jersey are included in the Mid-Atlantic census division. The East North Central Census Division ("ENCCD") is also included in this comparison, because, as will be demonstrated later, the counties comprising NFGDC's service territory have many characteristics that are more similar to the ENCCD than the MACD. The states included in the ENCCD include: Ohio, Indiana, Illinois, Michigan, and Wisconsin.

Table 1 summarizes the market share of the various energy types for home heating. As can be seen from this table, the counties served by NFGDC have a high share of households that use natural gas as their primary house heating fuel. The percentage of households that utilize natural gas as their heating source in NFGDC's service territory is closer to that of the ENCCD than either the MACD or state of Pennsylvania.

Table 1. Occupied Housing Units; House Heating Fuel; %					
	MACD	ENCCD	Pa	Pa Non-NFGDC Counties	NFGDC Counties
Utility Gas	54.7	73.1	51.3	49.6	69.3
Propane	3.1	7.5	3.0	2.8	5.1
Electricity	11.5	13.8	16.5	17.3	7.8
Heating Oil	27.8	3.4	25.5	26.7	13.1
Other	2.7	2.0	3.6	3.3	4.7

Another pertinent characteristic of the Company's service territory that more closely corresponds to the ENCCD as opposed to the MACD and the other Pennsylvania counties is the percentage of the population employed in manufacturing industries. This is summarized in Table 2.

Table 2. Employed Civilian Population 16 Years and Over, %					
	MACD	ENCCD	Pa	Pa Non-NFGDC Counties	NFGDC Counties
Industry: Manufacturing	12.3	20.1	16	15.4	22.8

Table 3 provides a summary of the affordability of owner occupied housing as reported by the Census Bureau. The Census Bureau defines selected monthly owner costs as follows:

"In Census 2000 the selected monthly owner costs are calculated from the sum of payment for mortgages, real estate taxes, various insurances, utilities, fuels, mobile home costs, and condominium fees. Listing the items separately improves accuracy and provides additional detail. When combined with income, a new item is created - Selected Monthly Owner Costs as a Percentage of Household Income. This item is used to measure housing affordability and excessive shelter costs. For example, many government

agencies define excessive as costs that exceed 30 percent of household income."[1]

The affordability of owner occupied housing for the NFGDC service territory also more closely follows that of the ENCCD than either the MACD or the remaining counties in Pennsylvania.

Table 3. Selected Monthly Owner Costs as a Percent of Household Income, %					
	MACD	ENCCD	Pa	Pa Non-NFGDC Counties	NFGDC Counties
0-29%	74.6	80.9	78.3	78.0	81.9
30% & Above	24.5	18.6	20.8	21.1	17.3
Not Computed	0.7	0.6	0.8	0.9	0.7

The high proportion of natural gas used as the source of heating households likely contributes to this affordability result. Table 4 below provides a summary of heating costs by source in NFGDCs service territory for the twelve months ended September 2003, September 2004 and September 2005.

Table 4. $/MMBtu Equivalent				
12 Months End	Electricity	Heating Oil	Gas	Propane
September 2003	31.64	11.54	9.23	17.82
September 2004	30.20	11.05	10.74	16.80
September 2005	29.71	14.19	12.09	21.61

NFGDC's extensive natural gas distribution system provides valuable access to the relatively lower cost natural gas heating alternative for

[1] http://factfinder.census.gov/home/en/epss/glossary_s.html

businesses and residents in the Company's service territory. NFGDC has made significant investments in distribution mains in order to provide such access. The Company has significantly greater investments in distribution mains than other gas utilities in the state. NFGDC has invested approximately 45% more in average distribution mains per customer than the remaining natural gas utilities in the state. Table 5 summarizes the miles of installed mains.

Table 5. Summary Distribution Mains

	Miles of Main	Customers	Customers per Mile of Main	Miles of Main per Customer	Feet per Customer
NFGDC	4,911	214,036	44	0.0229	120.9
Pa[2]	45,959	2,828,234	62	0.0163	85.8
Pa Non NFGDC	41,048	2,598,234	63	0.0158	83.4

This investment has brought, and continues to bring, significant economic value to the communities that the Company serves. An estimate of this economic value based on the alternative fuel shares for residential heating and the historical price of these alternate fuels in the Company's service territory is provided in Table 6 below. The amount of this value is approximately $180 million a year based on the residential service class and the fuel price differential alone. The overall economic value would be even greater when the fuel benefits to the non-residential class are calculated and consideration is

[2] Source: 2006; American Gas Association; *Gas Facts, A Statistical Record of the Gas Industry, with 2004 Data*

given to the externalized costs of the alternative fuels such as: increased dependency on foreign oil, increased costs associated with additional electric generation, and environmental costs.

Table 6. Estimate of Benefits to the Service Territory from Access to Natural Gas Supplies

Fuel	12 Months Ended 9/2005 Cost/Dth	Share	Share Excl. Nat Gas	Res Consumption (Dth)	Amount Alternative Greater than Natural Gas	Annual Savings
(A)	(B)	(C)	(D)	(E)	(F)	(G=FxE)
Electricity	$ 29.71	7.8%	30%	6,536,130	$ 17.62	$ 115,166,603
Heating Oil	$ 14.19	13.1%	50%	10,977,346	$ 2.10	$ 23,052,426
Propane	$ 21.61	5.1%	20%	4,273,623	$ 9.52	$ 40,684,893
Gas	$ 12.09	69.3%				
Total		95%		21,787,099		$ 178,903,921

A unique feature of the Company's service territory is the relative amount of seasonal properties. Table 7 below summarizes this feature. This is a relevant issue, since seasonal units tend to use less gas on average, the implications of which will be discussed later.

Table 7. Vacant Housing Units for Seasonal, Recreational, or Occasional Use, %

	MACD	ENCCD	Pa	Pa Non-NFGDC Counties	NFGDC Counties
% Seasonal	3.0	2.6	2.8	2.3	7.5

The Company has proposed the significant changes in rates and services in consideration of the current and likely future conditions in its service territory.

As can be seen from the large percentage of customers in the Company's service territory that heat with natural gas in Table 1 above, the Company has been successful in promoting natural gas use for its residential customers, and as seen from Table 6, the availability of natural gas as a primary heating source for residential customers has brought significant benefits to northwestern Pennsylvania. Based on these facts the efficient utilization of natural gas by the Company's customers is of greater importance to Northwestern Pennsylvania than other areas of the state. Also, because of the value of natural gas for heating compared to other fuels, it is important to continue to provide an incentive to invest in improving and expanding the natural gas infrastructure required to deliver beneficial natural gas fuel to customers in Northwestern Pennsylvania.

The current structure of the Company's rates does not provide such an incentive. Indeed, as currently structured the rates and tariffs of the Company actually provide a disincentive for the Company to promote the efficient utilization of natural gas by its customers or invest in expansion of its system. The rates and programs being proposed by the Company in this case are designed to eliminate these disincentives.

Q. *Have other parties with an interest in the efficient use of energy recognized such disincentives?*

A. Yes. Perhaps most significantly, the National Association of Regulatory Utility Commissioners ("NARUC") itself recognizes that there is a need to

address these disincentives. In a recently adopted "Resolution on Energy Efficiency and Innovative Rate Design" NARUC stated, among other things, the following:

> "...;and
>
> "**WHEREAS**, Energy conservation and energy efficiency are, in the short term, the actions most likely to reduce upward pressure on natural gas prices and to assist in bringing energy prices down, to the benefit of all natural gas consumers; *and*
>
> "**WHEREAS**, Innovative rate designs including "energy efficient tariffs" and "decoupling tariffs" (such as those employed by Northwest Natural Gas in Oregon, Baltimore Gas & Electric and Washington Gas in Maryland, Southwest Gas in California, and Piedmont Natural Gas in North Carolina), "fixed-variable" rates (such as that employed by Northern States Power in North Dakota, and Atlanta Gas Light in Georgia), other options (such as that approved in Oklahoma for Oklahoma Natural Gas), and other innovative proposals and programs may assist, especially in the short term, in promoting energy efficiency and energy conservation and slowing the rate of demand growth of natural gas; *and*
>
> "**WHEREAS**, Current forms of rate design may tend to create a misalignment between the interests of natural gas utilities and their customers; *now therefore be it*
>
> "**RESOLVED**, That the National Association of Regulatory Utility Commissioners (NARUC), convened in its November 2005 Annual Convention in Indian Wells, California, encourages State commissions and other policy makers to review the rate designs they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices ..."

A full copy of the NARUC resolution is provided in Exhibit 19, Schedule 3, pages 1 and 2.

The American Gas Association ("AGA") and the Natural Resources Defense Council ("NRDC") submitted a joint statement to NARUC in July 2004 stating, among other things:

> "Our shared objective is to give utilities real incentives to encourage conservation and energy efficiency. With properly designed programs, the benefits could be significant and widespread:
>
> - Customers could save money by using less natural gas;
> - Reduced overall use will help push down short-term prices at times when markets are under stress, reducing costs for all customers (whether or not they participate in the utility programs);
> - Utilities would recover their costs and have a fair opportunity to earn their allowed return;
> - State policies to encourage economic development could be enhanced by increased energy efficiency and lower business energy costs;
> - State PUCs would be able to support larger state policy objectives as well as programs that reflect the public's desire to use energy efficiently and wisely.
>
> In today's climate of rapidly changing natural gas prices, such reforms make good sense for consumers, shareholders, state governments, and the environment."

The AGA NRDC Joint Statement was reviewed and endorsed by the Alliance to Save Energy ("ASE") and the American Council for an Energy-Efficient Economy ("ACEEE"). A full copy of the AGA and NRDC joint statement is provided in Exhibit 19, Schedule 3, pages 3-6. Clearly a diverse range of parties understand a major impediment and flaw in utility rate

structures for the promotion of the efficient use of natural gas. They also recognize that current conditions in the market place and the environment support the effort to address this issue as soon as possible. The Company believes that the best time to address this is in this rate proceeding.

As will be demonstrated in my testimony, NARUC's concern that "Current forms of rate design may tend to create a misalignment between the interests of natural gas utilities and their customers" is indeed true for the Company's distribution system. Currently 65% of the Company's margin revenues are recovered through the usage charges of its customers. Over $59 million is recovered through residential and small non-residential customers' usage rates. The margin for the classes of customers served by the Company is provided as Schedule 19, Exhibit 4. For each percentage of usage that the small volume customer conserves the Company loses approximately $600,000 towards recovery of its fixed costs.

This clearly demonstrates that the Company incurs a significant penalty for declines in customer usage. This volumetric focus for the recovery of fixed costs also provides a serious disincentive for the Company to promote efficient energy usage by its customers. Despite these disincentives, the Company nonetheless promoted efficient energy utilization by its customers this past winter. The ability of the Company to act against its financial best interest has, however, reached its limits.

Q. What are the gains that the customer can expect from reduced consumption?

A. The most obvious gain is the reduction in the customer's bill from reduced consumption. Customers that utilize natural gas more efficiently would save on the natural gas supply rate they are charged. They will also save, at least in the short run, on the volumetric portion of their delivery rate. However, the volumetric adjustment of their delivery rate is subject to future increases as a direct result of their energy efficiency efforts. In other words, as customers reduce consumption, the Company is unable to recover its fixed costs, resulting in lower than reasonable rates of return which requires the Company to file rate cases where the delivery rates must be increased.

Additional benefits from energy efficiency can be expected at the wellhead. Reduced natural gas consumption due to energy efficiency efforts of customers will reduce overall demand for natural gas and, therefore, reduce wellhead prices. The resulting reduction in wellhead costs due to energy efficiency efforts will not only accrue to customers that have made those energy efficiency improvements ("participating customers"), they will accrue to all customers. Reduced prices at the wellhead will also reduce energy costs for manufacturers. An ACEEE study projects that the change in wholesale natural gas prices in the Midwest could decline by 4.4% in 2007 and up to 11.7% in 2020 from where they would otherwise be without an energy efficiency effort in the Midwest[3]. While it is impossible to precisely predict what the impact on wellhead prices would be due to increased energy

[3] April 2005; American Council for an Energy-Efficient Economy; www.aceee.org; *Impacts of Energy efficiency and Renewable Energy on Natural Gas Markets;* Report No E052; Table 13, p. 21

efficiency by customers on the Company's system (indeed, it is doubtful that energy efficiency gains achieved solely on the Company's system would have a material impact on the American natural gas market), it is clear that an energy efficiency program on the Company's system combined with efforts throughout the country would have a positive impact on reducing demand and, consequently, prices at the wellhead.

Q. What potential is there for increasing energy efficiency by customers on the Company's system?

A. There appears to be significant opportunity for both increasing energy efficiency by customers on the Company's system as well as maintaining the energy efficiency gains that have already been achieved. Two areas in particular offer significant promise: (1) thermostat reductions by customers, (2) and installation of high efficiency furnaces.

Regarding thermostat reduction, the United States Department of Energy ("DOE"), estimates that customers can save, on average, 10% annually on their heating bill from simply turning back their thermostat back by 10°-15° for 8 hours. The DOE estimates that savings as much as 1% for each degree can be achieved if the setback period is eight hours or longer. Exhibit 19, Schedule 5, pages 1-3, provides information from the DOE identifying these savings estimates. I note that under the Company's Low Income Usage Reduction Program ("LIURP"), whenever the Company installs a high

efficiency furnace under LIURP, a programmable setback thermostat is installed.

Customer savings can be even greater if overall thermostat reductions are put in place. EIA estimates for savings from a 1° lower thermostat setting for the ENCD is 4 Mcf. Exhibit 19, Schedule 5, page 4, provides the EIA information identifying this savings potential. This would represent a 4% decline in average residential usage. If all small volume customers reduced their thermostats by 1° resulting in a 4% decline of consumption, the Company would lose $2.4 million in revenue for recovery of its non-gas costs. This translates into an approximate 100 basis point decline in its achieved ROE.

The Company has conducted market research on customer behavior regarding thermostat settings for a number of years. That research indicates that the mean temperature that customers within the Pennsylvania Division set their thermostat at is 68° when at home and is 65° when they are not at home. Table 8, provides a summary of this information for three most recent studies conducted by the Company.

Table 8. Residential Customer Thermostat Settings						
	At Home			Not At Home		
	2006	2004	2000	2006	2004	2000
Less Than 64°	12%	7%	4%	35%	22%	17%
65°- 67°	18%	11%	9%	21%	25%	21%
68°- 70°	55%	60%	58%	35%	38%	42%
71°- 73°	8%	14%	19%	5%	8%	12%
More Than 73°	6%	5%	6%	3%	3%	5%
Don't Know	1%	3%	4%	1%	4%	3%
Mean (F°)	68	69	68	65	66	65

As can be seen from Table 8, there is a significant potential for increasing the amount that customers reduce their thermostat when customers are not at home.

Further potential for thermostat set back is available at night. Table 9, provides study results for customer behavior regarding lowering thermostats at night.

Table 9. Lower Thermostat at Night			
	2006	2004	2000
1 – 2°	7%	5%	8%
3 – 4°	15%	16%	12%
5 – 6°	11%	13%	11%
7 – 8°	5%	4%	3%
9 – 10°	3%	4%	2%
More Than 10°	1%	2%	1%
Do Not Lower Temperature	58%	53%	63%
Refused to Respond	-	3%	-

While Table 9 provides evidence that customers have reacted to higher prices by lowering their thermostats, it also demonstrates that there is further

potential for thermostat reductions since only 4% lower their thermostats by more than 8°. And 58% do not reduce their thermostats at all.

Table 10 below, estimates the potential savings in purchased gas costs if customers that currently turn back their thermostats less than 9°, reduced their thermostats by the indicated levels.

Table 10. Potential Savings in Purchased Gas Costs from Thermostat Reductions

	Thermostat Reduction		
	1°	3°	5°
% of Customers Lowering Thermostat less than 9° at Night	96%	96%	96%
Avg # of Residential Customers (Dec-Mar)	198,947	198,947	198,947
# of Customers Lowering Thermostat less than 9° at Night	190,989	190,989	190,989
Mcf Saved per Account	1	3	5
PGC Rate – Current	$13.05	$13.05	$13.05
Avg Customer Savings	$13.05	$39.15	$65.25
Total Potential PGC Savings	$2,492,235	$7,477,219	$12,462,032
PGC Savings at 50% Participation	$1,246,117	$3,738,610	$6,230,016
PGC Savings at 25% Participation	$623,059	$1,869,305	$3,115,508

Q. Does the Company have evidence that its efforts can influence customer behavior regarding energy efficiency efforts?

A. Yes. The Company asked customers in its surveys if they would voluntarily lower their thermostat setting during an unusually cold period. The response is provided in Table 11.

Table 11. Amount of Voluntary Thermostat Setback	
Will not lower temperature	25%
Lower 5-6 degrees	3%
Lower 3-4 degrees	22%
Lower 1-2 degrees	50%

Q. What is the Company proposing in this case to address the energy efficiency issues?

A. The Company is proposing to eliminate any disincentive currently in residential, small commercial and public authority, and small industrial customer rates for the Company to aggressively promote energy efficiency on its system. And the Company is proposing to implement an aggressive customer outreach effort in order to promote the efficient use of natural gas by its customers.

Q. How is the Company proposing to eliminate the disincentive currently in small volume customer rates for the promotion of energy efficiency?

A. The Company is proposing to implement a revenue decoupling mechanism ("RDM") in its tariff. An RDM is one of the innovative rate mechanisms that have been used by natural gas utility companies cited in the NARUC resolution for removing the disincentives for natural gas distribution utilities from promoting conservation on their systems.

Q. How will the proposed RDM operate?

A. The Company is proposing a new tariff rider, Rider I, Enhanced Energy Efficiency Program Cost Recovery Rider ("EEE Rider"), to implement the

RDM. The EEE Rider would provide a mechanism whereby any decline in average usage per account for the small volume customer classes would be recovered through an annual charge.

The EEE Rider will be a charge to be included in the natural gas delivery charges ("NGDC") of the small volume residential, commercial/public authority, and industrial service classes effective each August 1.

The EEE charge is designed to recover the lost margin associated with reduced consumption for the Residential, Commercial and Public Authority, and Small Volume Industrial ("SVIS") service classifications. Lost margin per account shall be determined by calculating the decline in Residential, Commercial and Public Authority, and SVIS consumption for the most recent 12 months ended January time period compared to volumes imputed in this case. The first time period to use in the calculation would be the 12 months ended January 2008.

The change in usage per account shall be multiplied by the sum of the appropriate rate classification delivery charge tailblock margin and the LIRA Rider surcharge effective in January to determine lost margin per account. The change in margin per account shall be multiplied by the average monthly number of accounts for the appropriate rate classifications for the most recent 12 months ended January. The total change in margin so calculated will be divided by the most recent 12 months ended January normalized volumes for the Residential, Commercial and Public Authority, and SVIS rate

classifications. Exhibit 19, Schedule 6 provides an example of the EEE charge mechanism for residential service customers.

Q. As proposed the EEE Rider will incorporate variances in consumption due to weather in the charge. Why is the Company proposing that variances in weather be included in determining the EEE charge?

A. It is appropriate to include the impact of the variances in weather in the EEE charge because the EEE charge is being proposed to recover deficiencies in revenues due to reduced customer consumption related to energy efficiency efforts of the Company. In periods where weather is colder than normal ("CTN") the Company may be recovering sufficient incremental revenue to fully compensate it for the loss of volumes associated with increased customer energy efficiency. Therefore, the EEE charge would operate such that if the average usage per account were greater than imputed usage the customers would receive a credit. Since the proposed EEE charge provides benefits to customers when weather is CTN it is only fair that the Company be provided similar benefits when weather is warmer than normal ("WTN").

Q. In past Company rate cases the Commission has disallowed Company proposals for a weather normalization clause. Is the EEE cost recovery mechanism a weather normalization clause similar to the proposals rejected previously by the Commission?

A. No. The EEE cost recovery mechanism is not a weather normalization clause. The EEE cost recovery mechanism is designed to promote energy efficiency

on the part of customers that will ultimately bring individual customers and the system as a whole overall benefits for efficient usage. As mentioned, previously, the recognition of actual consumption as opposed to normalized consumption provides for mitigation of the overall charge to customers during CTN periods. The EEE cost recovery mechanism could be designed based on normalized average usage per account; however, the cost mitigation aspects mentioned previously would be eliminated.

I note also, that the weather normalization features in the past were rejected by the Commission because no direct customer benefit from the clause was determined. The EEE program is designed to provide customers with substantial benefit through the promotion of energy efficiency. Therefore, the Company's proposed EEE cost recovery mechanism is reasonable and should be approved as proposed.

Further, I note that the Natural Gas Competition Act ("Act"), provides that,

"The Commission shall ensure that universal service and energy conservation policies, activities and services are appropriately funded and available in each natural gas distribution service territory."[4]

The EEE cost recovery mechanism as proposed complies with this requirement of the Act as does the Company's proposal to recover the costs of its conservation programs included in the proposed revenue requirement of this case.

[4] Natural Gas Competition Act, § 2203 (6) and § 2203 (8).

Q. Mr. Hanley in his ROE testimony proposes an ROE premium because the Company's Pennsylvania Division lacks a weather normalization clause. How should the EEE cost of recovery mechanism be reflected in any final ROE determination?

A. If the Company's EEE recommendation is approved as proposed, the recommended addition to ROE due to lack weather protection could be eliminated. It is important to emphasize, however, that reflecting the impact of weather in the EEE cost recovery mechanism is recommended as a mitigation mechanism for the EEE charge that is equitable to customers and the Company. The EEE cost recovery mechanism was not fundamentally designed to act as a weather adjustment mechanism, and indeed, could easily be calculated based on normalized usage per account as opposed to actual usage per account, if the mitigation aspects of the actual weather calculation were to be eliminated.

Q. Please review the Company's proposed outreach effort to promote enhanced energy efficiency efforts.

A. The Company is proposing to implement its "Save Today, Save Tomorrow" campaign. Exhibit 19, Schedule 7 provides a summary of this campaign. Exhibit 19, Schedule 7, provides a summary of the proposed Save Today, Save Tomorrow costs by program component. The costs of the campaign were included in the overall revenue requirement of the Company as

determined by Ms. Friedrich-Alf and as further summarized in Exhibit No. 104, Schedule 2, Page 38.

Q. Why does the Company believe that it can influence customer's energy efficiency decisions?

A. Market research that the Company has conducted provides evidence that messages provided by the Company are useful in influencing customer's energy efficiency decisions. More than half of the Company's customers believe that it is important that the utility provide them with information on expected natural gas price increases.

Customers were asked what resources they found the most useful in increasing awareness of expected natural gas price increases. The Table 12 below summarizes customers' responses:

Table 12. Resources Most Useful to Customers in Increasing Awareness of Expected Natural Gas Price Increases

Resource	Response: Extremely/Very Useful
News Story on Television	55%
Story in the Newspaper	42%
Newspaper advertisement	30%
TV advertisement	21%
National Fuel Gas	21%
News Story on the Radio	13%
Radio Advertisement	7%
State PUC	6%

Actual utility and PUC influence is likely higher than stated since both the Company and the PUC were contributors to or actually prompted the news stories relied upon to inform customers of increased prices and the need to

conserve. For example, Company and Commission issued press releases often prompt news stories on television, radio and in newspapers.

Q. In addition to the proposed RDM are there any other rate design changes that the Company is proposing to promote energy efficiency in its service territory?

A. Yes. Mr. Clark describes how these rate design changes were calculated and their impact on customer rates based on the overall revenue requirement requested in this case. I will provide an overall view as to why the Company has proposed to make these changes.

The Company is proposing a redesign in how it proposes to recover purchased gas demand costs ("PGDC"). PGDCs are associated with costs of transporting and storing gas on natural gas pipelines as well as a small component for the recovery of demand charges from suppliers of natural gas commodity. Currently, most PGDCs are recovered from all customers receiving sales service. Table 13, below summarizes the PGDC costs included in the current rates reflected in this proceeding. A small component of PGDCs is recovered through delivery charges of customers. These costs are recovered through per unit natural gas supply and delivery rates regardless as to what time of year the customer utilizes the Company's service. In other words a customer utilizing an Mcf of service in July is charged the same PGDC rate as a customer utilizing an Mcf in January.

Table 13. Summary of Purchase Gas Demand Charge Rates; Current and Proposed			
		Proposed	
	Current	Winter (Dec-Mar)	Non Winter (Apr-Nov)
PGDC Costs Included in Delivery Charge $/Mcf	$0.3078	$0.4632	$0.0000
PGDC Costs Recovered Through the Company's Natural Gas Supply Charge $/Mcf	$1.4488	$2.1793	$0.0000
Total PGDC Charges $/Mcf	$1.7566	$2.6425	$0.0000

The problem with this is that PGDCs are largely incurred to support the costs of providing customers service in the winter period. Since most customers utilize natural gas on the Company's system for heating purposes, customer's demand is greatest in the winter period. The Company must incur upstream pipeline and storage costs largely in order to support this winter demand. In order to properly reflect the costs that winter consumption causes the Company to incur, and provide those customers that decrease their demand through energy efficiency savings with the value of that reduced demand, the Company is proposing to redesign the recovery of PGDC to the winter months of December through March.

Q. Is the Company proposing any other changes in its rate structure?

A. Similar to the PGDC rate redesign, the Company is proposing that non-purchase gas costs be recovered through rates in a manner that is more consistent with how the Company incurs them. Non-purchase gas costs are

the costs incurred by the Company to invest in and support the pipeline infrastructure that permits delivery of natural gas supplies to customers. The costs of investing in and maintaining the Company's pipeline infrastructure do not vary by the amount of gas transported through the pipelines. Therefore, the Company is proposing to redesign the cost recovery of its fixed costs from the volatile tailblock delivery rate to the customer charge and less volatile first block of its delivery rate. This non-gas cost rate redesign will help to mitigate the impact of the seasonal recovery of the PGDC rates and more accurately reflect how the costs of providing service to its customers is incurred by the Company.

Q. What is the impact of these rate redesigns on customers?

A. Exhibit 19, Schedule 8, provides the impact of these rate redesigns on customers. As can be seen the rate impact of the seasonal PGDC rate redesign is largely mitigated for the average residential customer by the moving of fixed non-gas cost charges from the tailblock to the first block and customer charges. Page 1 of Exhibit 19, Schedule 8, provides the summary of total residential customer bills by month for the average residential customer consuming 100 Mcf of natural gas annually at: (1) current rates, (2) the proposed increase with a non-seasonal rate design, and (3) the proposed seasonal rate design. The final three columns of Exhibit 19, Schedule 8, Page 1, provides a month to month comparison of the proposed seasonal rates to the proposed increase under a non-seasonal rate design. That comparison

demonstrates the mitigating nature of the proposed rate redesign as it relates to the PGDC rate and margin.

Q. Why make these proposed changes if the impact of both is largely offsetting?

A. The impact of these rate changes only appears to be offsetting. There are positive gains to the system to be made from these changes. As mentioned above these changes are more consistent with cost causation. These changes will also support the potential expansion of the Company's system in an efficient manner.

Q. How will the proposed redesign in cost recovery of non-gas costs support the efficient expansion of the Company's system?

A. By moving margin recovery from the tailblock to the first block and customer charges, the Company will be able to recover more of the costs of installing new mainline and service line for new customers in the tariff rates charged to the customer, and thereby require less of an upfront contribution from customers for the extension of facilities to customers. The average new home is more efficient than the existing home in the Company's service territory. The relationship between the age of housing stock and the average consumption of residential customers for a number of geographic areas served by the Company will be explained later in my testimony. Overall, the average existing customer consumes 8.5% more gas than a new residential customer as further explained in Ms. Zablonski's testimony.

Q. Have you determined the impact of the rate redesign on residential customers that consume different amounts of natural gas during the year?

A. Yes. Exhibit 19, Schedule 8, Page 2 provides the summary of bills for the following categories of residential customers: (1) the average residential customer with an average annual consumption of 100 Mcf ("average residential customer"), (2) the average consumption for residential customers on the Company's system that use 50 Mcf or less annually ("small volume residential customer"), and (3) the average consumption for residential customers that use 50 Mcf or more annually ("larger volume residential customers"). As can be seen from Exhibit 19, Schedule 8, Page 2, the margin that a small volume residential customer provides to recover the non-gas costs of the Company is substantially less than that provided by the average residential customer. Exhibit 19, schedule 8, Page 2 demonstrates that small volume customers contribute 41%[5] less than the average residential customer toward the recovery of non-gas costs. It is important to keep in mind that there is no difference from a system operations perspective between service to a small volume residential customer and service to the average residential customer other than the amount of gas supply and associated pipeline that the Company must purchase. In other words, the size of the service line, the meter set, and the capacity of a distribution main line installed to meet the requirements of a residential customer will be the same regardless as to whether the residential customer uses 100 Mcf, 32.9 Mcf, or 111.5 Mcf.

[5] 41% = (422.91-249.63)/422.91

Q. Based on the lower than average usage for new residential accounts, are you proposing changes to the Company's mainline extension policy?

A. Yes. The Company is proposing to update of the factors utilized to determine usage for the facility extensions of residential customers. Exhibit 19, Schedule 9 provides a summary of the updated factors used to determine incremental consumption for new residential customers.

The updated household heating factors are provided for the following types of residential homes: (1) Single Family Home, (2) Apartment/Condominiums, and (3) Manufactured Homes. Appliance consumption information was also updated in the proposed tariff as provided in Table 14 below:

Table 14. Appliance Consumption to Be Utilized in Load Justified Investment for New Residential Customers[6]

Appliance	Assumed Consumption (Mcf)
Water Heater	20.4
Range	7.6
Clothes Dryer	3.6

In addition the space heating and appliance information, the Company will also estimate consumption for any specialty gas appliances (i.e., garage heaters, pool heaters, natural gas fireplaces, etc.) that the customer may have installed in their home.

[6] American Gas Association, 2004 AGA Residential Market Survey, Table 14, p.16. Estimate is for the ENCCD.

Q. From the bill impact presentation it is apparent that lower volume residential customers will experience a greater percentage increase in their bill on average after the rate design redesign of cost recovery than higher volume residential customers. Have you done an analysis of the characteristics of various residential customers by amount of volume used?

A. Yes, I have done an analysis of the consumption characteristics of customers based on median income and age of home. The approach used was to compare census information by zip code to volumetric consumption for residential customers by zip code.

Q. Please describe the zip code study conducted by the Company?

A. The zip code study analyzed the consumption characteristics of residential customers in the major communities served by the Company. The study looked at the overall consumption characteristics for zip codes with approximately 1000 or more residential customers being served.

Exhibit 19, Schedule 10, provides a graphical summary of that analysis. Page 1 of Exhibit 19, Schedule 10, provides the average consumption per residential account for each zip code in the Company's service territory sorted from lowest income zip code on the far left of the x-axis of the graph to the highest income zip code on the far right of the graph. The y-axis represents the average residential usage per account for each zip code on the graph. Bracketed at the top of the graph is the lowest income quartile of the zip codes analyzed and the highest income zip codes analyzed. The dashed line running

through the middle of the graph provides the average usage for all residential accounts for the zip codes analyzed. As can be seen from the graph 7 out of 10 zip codes in the lowest income quartile are above the average consumption for residential customers. I note that the three zip codes that are below the average consumption for all zip codes analyzed are only slightly below the average.

For the highest income quartile, 8 out of the 10 zip codes are below the average usage for the zip codes analyzed. Included on the graph is a trend line of average volume per account. That trend line demonstrates the decline in residential consumption per account as income increases.

Q. What does page two of Exhibit 19, Schedule 10 demonstrate?

A. Page two of Exhibit 19, Schedule 10, provides a likely explanation for the reason why this trend of lower consumption per account as income increases. Page two adds an analysis of the percentage of homes built after 1980 by zip code. This is important since significant changes in housing stock building codes and furnace efficiencies were established post 1980. The y-axis on the right hand side of the graph provides the scale for the percentage of homes built 1980. The bars on the graph provide the percent of homes built after 1980 for each zip code analyzed. The dotted line provides the average percentage of homes built post 1980.

As can be seen from the graph, for the lowest income quartile, 7 out of the 10 zip codes have housing stock built after 1980 below the average percentage

for all zip codes analyzed. For the highest income quartile all zip codes have a higher percentage of housing stock built after 1980 than the average for the zip codes analyzed.

This result is not that surprising. One wouldn't expect that low-income customers would be able to build newer homes. Newer homes, of course have, newer appliances including more efficient furnaces. The fact that higher income households are more likely to be in newer housing stock than lower income households likely explains the fact that higher income zip codes tend to consume less natural gas per account than lower income zip codes.

Q. Please comment on the zip code with the lowest usage per account.

A. This zip code has a high proportion of seasonal homes (24%) compared to the already relatively high seasonal proportion of homes in the counties served by the Company (7.5%). It is likely that a number of Company accounts for this zip code are seasonal homes. Since seasonal homes are likely vacant for a portion of the year, their consumption is likely to be lower than non-seasonal homes. The Company's proposal to recover more non-gas costs from customer charges and the first block of residential rates will lead to greater cost recovery from seasonal accounts. This observation is consistent with the overall observation that low-income customers are likely to use more gas than higher income customers since it is unlikely that low-income customers would own seasonal homes.

Q. Do the conservation programs and the rate design changes that the Company is proposing provide the potential for reductions in the bills of lower income customers?

A. While all customers can benefit from utilizing natural gas efficiently, lower income customers have the greatest potential for usage reduction associated with energy efficiency initiatives since they tend to use greater amounts of natural gas. In addition, the proposed rate design changes eliminate the inequities resulting from the under recovery of fixed costs from small volume residential customers and the over recovery of costs from residential customers with greater usage.

Q. Please summarize the initiatives the Company is proposing in this case to enhance the potential for competition for NGS service on its system.

A. The Company is proposing two major initiatives to enhance the potential for competition for NGS service on its system. These initiatives include: (1) more comprehensive delivery rate unbundling, and (2) a pilot program for the purchase of NGSs' receivables program.

Q. The Commission has instituted an investigation in to the reasons why competition for natural gas supply service has not developed in Pennsylvania ("Competition Investigation").[7] Why are you proposing the changes in this proceeding?

[7] *Investigation into the Natural Gas Supply Market: Report to the General Assembly On Competition In Pennsylvania's Retail Natural Gas Supply Market,* Investigatory Order and Report to the General Assembly, Order entered October 6, 2005 at Docket No. I-00040103.

A. It is apparent from the Competition Investigation Order that the Commission is concerned about the limited number of Natural Gas Suppliers other than the utilities ("NGSs") and the low level of customers choosing NGSs in most local distribution company service territories. The Company believes it is appropriate to recommend the implementation of the initiatives listed above to determine if interest in competitive alternatives of natural gas supply can be increased in its service territory.

Q. The Company is proposing a further unbundling of its rates. Can you explain the current structure of the Company's rates?

A. Yes. Currently each rate schedule of the Company is unbundled. By an unbundled rate structure I mean that the charges of the Company are separated into delivery and purchased gas cost components. Only customers that choose to receive natural gas supply service from the Company are charged the Company's purchased gas supply rate. All customers, including customers that choose a natural gas supplier other than the Company, are charged the Company's delivery rate.

The Company is proposing to recover an existing cost component of the delivery charge rate, through a percentage increase to purchased gas cost ("PGC") rates instead of through the delivery rate charge of the Company as currently structured.

Q. What are the costs that the Company is proposing to move from the Company's delivery rate charge to the purchased gas charge?

A. The Company is proposing that an amount of non-gas costs that could be claimed to be associated with the purchase gas function, be recovered through a percentage increase in the PGC rate. These costs are presented in Exhibit 111, Schedule 4, Page 4.

The Company is proposing that these costs be recovered through a merchant function charge ("MFC") to be included in PGC rates. The MFC would apply as a percentage addition to purchased gas costs.

Q. What are the costs proposed to be included in MFC?

A. The Company is proposing that two cost components be included in the determination of the MFC: (1) storage working capital costs, and (2) a portion of uncollectible accounts attributable to PGC costs.

Q. Why were these particular components of the Company's cost of service proposed to be included in the MFC calculation?

A. These costs have direct relationship to the Company's role as a merchant of natural gas supplies. The less gas supply that the Company needs to purchase for its customers the lower the working capital requirement would need to be for storage inventory. Also, if the customers that enroll for service with an NGS had at similar mix of payment troubled and non-payment troubled customers as the current mix of the Company's sales customers, the Company's overall level of uncollectibles would decline from where they would be without such enrollment. Of course, the assumption that customers will enroll with an NGS at a similar mix of payment troubled and non-

payment troubled customers cannot be determined until such enrollment occurs. Indeed, it is conceivable, through customer credit checks, that NGSs would enroll only good paying customers leaving the Company to serve poorer paying customers. The Company's proposed purchase of receivables program (discussed later) would mitigate this risk somewhat through the discount of receivables purchased from NGSs that utilize the Company's billing service. There would be some exposure, however, to NGSs that provide their own billing service and choose to serve only good paying customers. Therefore, the Company would propose, after twelve months of actual experience under the proposed MFC, to revisit the issue of an appropriate MFC for NGSs that do their own billing. If it is found that such NGSs target only good paying customers, the Company would be permitted to adjust the MFC accordingly for such NGSs that do their own billing.

Q. Why were additional costs not added to the MFC?

A. The Company continues to have supplier of last resort ("SOLR") responsibilities for the customers on its system. Since the Company cannot avoid SOLR responsibilities, the associated costs of being the SOLR are not avoidable; therefore, no additional costs were included in the MFC.

Q. Please describe the Company's proposed purchase of NGS receivables ("POR") program.

A. The Company is proposing a NGS POR pilot program. The pertinent features of the proposed NGS POR pilot program included in the Company's proposed Small Aggregation Transportation Service ("SATS") tariff are as follows:

(1) The Company will purchase the receivables of residential accounts, commercial and public authority accounts, SVIS accounts, and IVIS accounts of NGSs that utilize the Company's standard billing service included in the SATS rate schedule.

(2) The POR pilot will have a minimum two-year term cancelable upon 1 years notice to NGSs.

(3) Under the POR pilot the Company will purchase the natural gas supply receivables of the NGS at a discount and without recourse.

(4) For residential accounts the POR discount will be 3.07%. For non-residential accounts the POR discount shall be 0.81%.

(5) The Company will remit payment to the NGS for purchased receivables on the 23rd day following the issuance of the bill to the customer.

(6) The Company will administer consumer protections including discontinuance procedures without discrimination between NGS customers and customers that continue to receive natural gas supply service from the Company. To avoid providing a preference to NGS customers, the Company shall be permitted to disconnect service to customers for failure to pay the total receivable amount including the

NGS receivable purchased by the Company. The Company shall follow all termination requirements applicable to termination of its sales service customers when terminating accounts that the Company has purchased an NGS's receivable.

(7) The Company will be permitted to assess late payment charges to the purchased NGS receivable at the rate it charges its sales service customers.

(8) The Company may obtain deposits from the customer for the NGS portion of the bill for any account which the Company purchases NGS receivables such deposits shall be obtained in a similar manner as the Company obtains deposits for its sales service customers.

Q What ROE recommendation is utilized by the Company in the calculation of its revenue requirement?

A. I am recommending that the high end of the ROE range presented by Mr. Hanley be utilized for calculating the revenue requirement of the Company in this proceeding.

Q. Why do you recommend utilizing the high range?

A. I recommend utilizing the high range because of the overall strength of the Company's management of its local distribution system as demonstrated by the following. The Company's successful marketing and system expansion efforts, as demonstrated by its relatively high market share for heating fuel and its greater than average investment in distribution main lines should be

recognized in the ROE determination. Also, it is appropriate that the Company be provided sufficient incentive for the Company to continue to invest in natural gas infrastructure to provide access to relatively low cost natural gas for the heating and processing requirements of the customers in its service territory.

The Company's innovations in service to low-income customers including the LIRA rate schedule and the significant benefits provided by the Company's LIURP program should also be considered. Another factor that should be considered is the Company's effort to promote customer energy efficiency this past winter. Recognition of the innovations proposed by the Company in this case for the efficient utilization of natural gas and the innovations proposed by the Company in this case related to promoting the opportunities for enhancing competition on its system is appropriate in determining the ROE utilized in setting rates. The Company has also, operated it system in an efficient and low cost manner consistent with providing safe and reliable service and has helped neighboring customers of the Kaylor Gas Company, while balancing the overall interest of customers on the Company's system.

Q. Does this complete your testimony?

A. Yes, at this time.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
DIRECT TESTIMONY OF
JOHN J. POLKA

Q. State your name and business address.

A. My name is John J. Polka Jr., and my business address is 6363 Main Street, Williamsville, New York, 14221.

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

A. I am employed by National Fuel Gas Distribution Corporation ("Distribution") as the General Manager of Gas Supply Administration.

Q, What are your duties as General Manager?

A. I report directly to the Vice President and I assist in implementing Distribution's Gas Procurement, Transportation and Exchange and Gas Planning policies.

Q. Summarize your prior work experience and education.

A. I received a Bachelor of Science Degree in Civil Engineering from the State University of New York at Buffalo in 1978. I received my New York State Professional Engineering License in March 1987. I am a director of the Independent Oil and Gas Association of New York, a member of the Independent Oil and Gas Association of Pennsylvania, and a member of the National Society of Professional Engineers.

In June 1978, I joined Distribution as a Management Trainee. I was transferred and promoted in December 1978 to Distribution's Operations-North as a Junior Engineer. In January 1982, I was transferred to Distribution's Industrial Engineering Department. In May 1982, I was transferred to Distribution's Engineering Department. Holding various positions and responsibilities in the

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Engineering Department, I was promoted to Assistant Engineer in July 1982, Associate Engineer in July 1986, Senior Engineer in November 1988, and Engineer-in-Charge in March 1994. On January 1, 2001, I was transferred to National Fuel Gas Supply Corporation ("Supply") and assigned to the Gas Control Department as Engineer-in-Charge. On June 16, 2001, I was transferred back to Distribution and obtained the position of Assistant General Manager of Distribution's Gas Supply Administration Department with responsibilities for Gas Planning and Gas Accounting. On April 1, 2002, I was promoted to my current position of General Manager of Gas Supply Administration. I direct Distribution's Gas Procurement, Gas Accounting, Transportation and Exchange, and Gas Planning functions associated with the Gas Supply Administration Department.

Q. What is the subject of your testimony?

A. The subject of my testimony is Exhibit No. 17, which provides a summary of Distribution's purchase practices. I also discuss in that exhibit the procedures involved in tracking the Federal Energy Regulatory Commission's ("FERC") rate activities of Distribution's upstream pipelines. Finally, I am also sponsoring Exhibit No. 117. The subject matter requested in Exhibit No. 117 is included and fully explained in Exhibit No. 17.

Q. Please explain Exhibit No. 17.

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JOHN J. POLKA

A. Exhibit No. 17 contains copies of the forms of contracts under which Distribution currently is offering to purchase locally-produced gas. Exhibit No. 17 also contains copies of short-term contracts for the purchase of gas transported by the long-line pipelines. Distribution also has firm, longer-term contracts with producers for gas supplies that are transported by the long-line pipelines. Exhibit No. 17 includes a copy of Distribution's pro forma master long-term gas purchase contract. The specific contracts, however, are individually negotiated and are therefore, proprietary and confidential. Distribution is willing to make these contracts available to appropriate parties upon implementation of procedures that protect the confidentiality of the contracts.

Q. Please provide a summary of how Distribution tracks its upstream pipeline rate activity.

A. Distribution undertakes efforts at the FERC and at the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") in proceedings involving its upstream pipelines, as well as generic industry-wide proceedings that may have an impact on Distribution and its customers.

Q. Please summarize how Distribution tracks its upstream pipeline FERC rate activity.

A. Distribution actively represents its positions at the FERC, defending its interests as a local distribution company in all cases where such action is appropriate, including FERC rulemakings, generic proceedings and the rate and certificate

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proceedings of Distribution's upstream pipelines, including Supply. In this regard, Distribution's Vice President, Assistant General Manager, and Senior Attorney, as well as other regulatory and gas supply personnel in the Gas Supply Administration Department and in the Rates and Regulatory Affairs Department, are responsible for identifying and/or reviewing proceedings at FERC that affect or potentially affect Distribution and its customers.

When such a proceeding is identified, Distribution will intervene and participate to ensure appropriate representation of Distribution and its customers. Such participation may include attending meetings and public conferences, presenting comments, or filing formal pleadings. Where appropriate, Distribution also pursues issues in litigation.

To the extent feasible, Distribution looks to work with others whose positions are consistent with Distribution's, thereby sharing the costs of witnesses, consultants and other expenses. For example, Distribution is an active member of the American Gas Association and North American Energy Standards Board. In addition, Distribution retains the services of an outside law firm for assistance with significant FERC matters.

Q. Does Distribution anticipate any significant changes as a result of any actions by the FERC?

A. Yes, as previously reported, Order No. 2004, *et seq.*, is the FERC's new affiliate rule. Originally issued on November 25, 2003, in Docket No. RM01-10, the rule

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DIRECT TESTIMONY OF
JOHN J. POLKA

is the culmination of the FERC's September 2001 Notice of Proposed Rulemaking ("NOPR") and the subsequent exchanges of analyses and comments by Staff and industry participants. Order No. 2004 adopts entirely new standards of conduct for both interstate natural gas and electricity transmission providers ("Transmission Providers") and their "Energy Affiliates." Generally, the new rule, in part, requires that a Transmission Provider's employees engaged in transmission system operations must function independently from employees of the Energy Affiliate, and provides that local distribution companies are Energy Affiliates if they engage in off-system sales or other prohibited activities.

Q. What actions has Distribution taken in response to Order No. 2004, *et seq.*?

A. In an effort to mitigate the impact of Order No. 2004 on Distribution's ability to source the lowest cost gas supplies while maintaining reliable and continuous service, Distribution is actively involved in FERC Docket No. RM01-10, which efforts have culminated in the commencement of an on-going proceeding before the D.C. Circuit. Distribution is also active in Docket No. TS04-248 regarding Supply's Petition for Limited Waivers of Order No. 2004 Standards of Conduct. Generally, Distribution has pursued and supported FERC waivers regarding the ability to continue sharing the gas dispatch center, including its staff, and to resume making off-system sales. Distribution has also participated in meetings with the FERC Staff in an effort to optimize Distribution's situation.

Q. What changes has Distribution implemented as a result of Order 2004?

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DIRECT TESTIMONY OF
JOHN J. POLKA

A. Distribution's and Supply's long-running integrated gas operations arrangement would no longer be allowed if Distribution were an Energy Affiliate of Supply. The required separation under the rules would result in increased operating costs and a broad reduction in efficiency and reliability. As such, on September 22, 2004, Distribution ceased off-system sales activities in order to maintain non-Energy Affiliate status under FERC Order 2004. This does not include limited storage inventory transfers performed in connection with Distribution's state-approved retail unbundling programs.

In addition, personnel associated with the administration of local production contracts and gas quality programs were transferred from Distribution to Supply on February 1, 2005. The transfer was conducted to further separate Distribution's Gas Supply Administration Department from Supply in order to support Supply's request for partial waiver of the separation of functions requirements and information sharing prohibitions of the Standards of Conduct, which is currently before the FERC in Docket No. TS04-248.

In addition to these personnel changes, on February 22, 2005 Distribution filed comments in support of Supply's compliance plan, pre-existing waiver justification, third supplemental petition and motion for clarification filed with the FERC on February 3, 2005 (February 3 Filing). Supply's February 3 Filing was made in Docket No. TS04-248 in response to the FERC's September 20, 2004 Order (September Order). In its September Order, the FERC denied Supply's

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DIRECT TESTIMONY OF
JOHN J. POLKA

request to exempt Distribution from Energy Affiliate status, but noted that, with "modest restructuring" Supply would be able to continue to provide dispatch services to Distribution.

Q. Please expand on the impact of separation.

A. Distribution believes that, if the FERC denies the request to continue sharing the gas dispatch center and its staff, the estimated cost to build a separate Distribution gas dispatch center would be about $600,000 to $1,000,000, and the estimated additional expense to operate the separate dispatch center would be about $1,300,000 per year. These costs would be allocated between the New York and Pennsylvania jurisdictions. However, given the extensive interconnection between Distribution and Supply, the detrimental impact on reliability that would result from a separate gas dispatch center is impossible to quantify. Ms. Friedrich-Alf provides a recommendation for recovery of these costs if they need to be incurred.

Q. Has Distribution explored alternatives to preserve the benefits associated with off-system sales in anticipation of the FERC action denying the requested relief?

A. Yes. The Company has utilized capacity release and storage fill services to mitigate the loss of off-system sales.

Q. Does this conclude your testimony?

A. Yes it does.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
DIRECT TESTIMONY OF SHEILA SUAREZ

Q. Please state your name and business address.

A. My name is Sheila Suarez, and my business address is 6363 Main Street, Williamsville, New York 14221.

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

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

Q. Will you state briefly your educational background and experience?

A. I graduated from Canisius College in 1986 with a Bachelor of Science Degree in Accounting. In 1993 I completed a Master of Business Administration Degree at the State University of New York at Buffalo. In June 1986, I was employed by Distribution as a Junior Rate Analyst in the Valuation Department, which has since been reorganized into the Rates and Regulatory Affairs Department. I was promoted in March 1990 to Rate Analyst II, In July 1993 I was promoted to Rate Analyst III, and in June 2001 I was promoted to Rate Analyst IV, my present position.

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

A. I am testifying to certain required exhibits pertaining to gas costs and Distribution's tariff.

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

A. I am responsible for Exhibits Nos. 12, 14 and 15 in the historic test

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DIRECT TESTIMONY OF SHEILA SUAREZ

year the twelve months ended January 31, 2006 and Exhibits Nos. 112, 114 and 115 in the future test year the twelve months ended January 31, 2007.

Q. Please describe Exhibit 12.

A. Exhibit No 12 includes eight schedules and is historic gas cost information for the 12 months ended January 31, 2006 filed in accordance with Pa. P.U.C. regulations. Schedules 1, 2, 3, 4, 5, 6, and 7 are self explanatory.

Q. Please Explain Exhibit No. 12, Schedule 8.

A. Pursuant to 52 Pa. Code § 53.61(c) Distribution is incorporating by reference its annual 1307(f) filing at Docket R-00050216. The preliminary filing was made on January 3, 2005, and the tariff filing with additional data was made on February 1, 2005. The data are compiled in twenty-six (26) separate Exhibits, which detail the Company's gas procurement policy and calculate the purchased gas cost rate. Rates are effective through July 31, 2006. The Company is also incorporating by reference 1307(f) filing at Docket R-00061246. The preliminary filing was made on January 3, 2006, and the tariff filing with additional data was made on February 1, 2006. The data are compiled in twenty-six (26) separate Exhibits, which detail the Company's gas procurement policy and calculate the purchased gas cost rate. Rates will be effective August 1, 2006 through July 31, 2007 with updates for actuals through June 2006

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DIRECT TESTIMONY OF SHEILA SUAREZ

once the compliance filing is made in July 2006, and rates will be updated quarterly thereafter.

Included in Exhibit No. 12, Schedule 8 is the 1307(f) quarterly filing update of purchased gas cost and revenues for Case R-00050216 which calculates the purchased gas cost rate that became effective February 1, 2006. The rate that became effective February 1, 2006 resulted in a purchased gas cost rate of $13.0432 per Mcf or a decrease of $0.7681 per Mcf. Also included in Exhibit No. 12 is the updates for purchased gas cost and revenues through February 2006 as included in the settlement document for Case R-00061246.

Q. Please describe Exhibit No. 14.

A. Exhibit No. 14 is composed of two schedules pertaining to Distribution's tariff. Schedule 1 provides a summary of tariff filings and other reports submitted to the Commission made during and subsequent to the historic year, the twelve months ended January 31, 2006. Schedule 2 is composed of the current tariff, pending tariff supplements and Supplement No. 61 the proposed tariff associated with this rate case filing at Docket No. R-00061493.

Q. Please describe the changes in the proposed tariff.

A. 1. Seasonal Rate Design - Service will be provided at different rates for non-winter (April - November) and winter (December - March)

consumption. This proposed rate design is discussed further in Mr. Clark's testimony.

2. Merchant Function Charge - A charge of 3.069951% for residential service and 0.805409% for non-residential service is being added to the Natural Gas Supply Charge and Gas Adjustment Charge as included in Rider A. Please refer to Mr. Meinl's testimony for discussion of this charge.

3. Small Aggregation Transportation Supplier Service ("SATS") - The Company is proposing changes to the rate schedule SATS to allow for the purchase of supplier receivables by the Company. Please refer to Mr. Meinl's testimony for further explanation.

4. LJI - The residential consumption variables have been updated as explained by Mr. Meinl in his testimony.

5. Changes are being made to the following pages in the Company's tariff for clarification purposes: pages 11 (LJI-miscellaneous gas equipment), 16B (System downgrades), 17 (LJI refunds), 20 (refusal or termination of service, and 110 and 116 (DMT telemetering).

6. Rider I - Enhanced Energy Efficiency Program Cost Recovery - The purpose of this rate, which will be discussed by Mr. Meinl in his testimony, is to recover lost margin associated with reduced consumption due to the Company's proposed Enhanced Energy Efficiency Program.

Q. Please describe Exhibit No. 15.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
DIRECT TESTIMONY OF SHEILA SUAREZ

A. Exhibit No. 15 is composed of three schedules and provides information on corporate history and the system map.

Q. Please describe Exhibit Nos. 112, 114 and 115.

These exhibits are filed in accordance with Pa. P.U.C. regulations and are self explanatory.

Q. Does this conclude your testimony?

A. Yes, at this time.

National Fuel Gas Distribution Corporation
Direct Testimony of Scott E. Swartzfager

Q. Please state your name and business address.

A. My name is Scott E. Swartzfager, and my business address is 1100 State Street, Erie, PA 16501.

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

A. I am employed by National Fuel Gas Distribution Corporation ("Distribution" or "National Fuel") as Area Manager of the Energy Services Department in Pennsylvania.

Q. Please state briefly your educational and professional experience.

A. I graduated from the Clarion University of Pennsylvania (CUP) in 1982 with a Bachelor of Science Degree in Business Administration. I joined National Fuel in 1987 as a supervisor in the Area Development Department and have advanced through various positions before assuming my present responsibilities in the Energy Services Department in May of 2003. As Area Manager of Energy Services, I am responsible for Distribution's sales and marketing activities for the Pennsylvania division.

Q. What is the purpose of your testimony?

A. My testimony reviews the various competitive situations facing Distribution including those of pipeline and local production bypass as well as competition from alternative forms of energy such as electricity. I will review Distribution's responses to these threats including its transportation service, specialized rate designs and trade ally programs. Additionally, I will review those programs and

initiatives, including an overview of research, development and demonstration programs, which enable Distribution to meet the performance criteria set for electric and gas utilities adopted by the Commission under Section 523(b) of the Public Utility Code.

Q. Please describe the competitive environment in Distribution's markets.

A. Distribution is affected by a variety of competitive market forces. The most obvious is in the form of inter-fuel competition (oil, coal, electricity, propane, biofuels). There is also intra-fuel competition with other providers of natural gas that construct facilities to physically bypass Distribution. However, there are other competitive pressures, sometimes equally as threatening to Distribution's throughput. They are inter-company and intra-company competition. Inter-company competition occurs when one firm, for example a pipe manufacturer, is in competition with other pipe manufacturers either within or outside of our service territory. Intra-company competition is characterized by situations where a corporation has one plant located within our territory that is in competition for production with another plant that is located outside of our territory. All of these situations contribute to the intensity of our competition.

Q. Please explain how Inter-company or Intra-company competition affects your throughput.

A. Since Distribution's sales to the manufacturing or process industries can often be directly related to units of output, as the customer's production levels increase or decrease because of competitive forces, then so will Distribution's throughput.

In addition, there is a side effect on Distribution's throughput level that is dependent upon the success of Distribution's customers. To the extent that customers are successful, jobs may be created or retained which affect the overall economic viability of the marketplace. Therefore, Distribution's objective has been, and continues to be, to provide its product at a price or rate, which enables its customers to compete. Distribution works extensively with its customers to assist them in achieving their competitive goals.

Q. Please describe the overall economic viability of Distribution's marketplace.

A. Distribution's industrial throughput for the twelve months ended September 2000 was 18,026 MMcf and for the twelve months ended September 2005 was 13,158 MMcf, a decline of 4,868 MMcf or 27% for the five-year period. This is mainly attributable to plant closings, plant relocations and reductions in customer production due to economic conditions.

Recent bankruptcy reports reinforce the severity of the current economic environment. The U.S. Bankruptcy Court for Western Pennsylvania has set new records for bankruptcy filings in each of the past five years. A reported 30,427 western Pennsylvania households and businesses filed for bankruptcy during 2005, nearly double the 15,692 filed in 2001 and almost five times the 6,300 filed

in 1995. According to our own limited tracking reports for significant plant closings and bankruptcy filings within our service territory, 31 industrial customers closed operations and/or declared bankruptcy since 2001. These accounts alone represented over 3.1 Bcf of throughput on our system as little as five years ago. For these same customers, throughput for the twelve-month period ended December 2005 totaled 1.4 Bcf, a decline of 1.7 Bcf or nearly 54%.

Q. Please explain briefly gas-on-gas competition that confronts Distribution.

A. "Bypass" is the primary form of gas-on-gas competition facing Distribution, with bypass being defined as the delivery of natural gas supplies directly to end-users, excluding the services of the local distribution company ("LDC"). As in the past, this threat continues to represent a significant competitive threat to Distribution today. Producers continue to seek direct markets for local gas production. While this local production threat has traditionally existed in Northwestern Pennsylvania because of the presence of local gas reserves, Distribution has also witnessed a recent rise in the threat of bypass to interstate pipelines or gathering systems. The threat of bypass in general is as pronounced as ever due to the economic and market factors noted previously.

The net effect of bypass is to deprive the LDC of operating revenue and to spread the fixed costs of operating its system to a smaller base of customers and throughput.

Q. How substantial is the threat of bypass?

A. Local producer bypass is and will continue to be a very competitive issue. Distribution's large Pennsylvania customers are literally surrounded by local gas reserves. The opportunity for long-term contracts with end-users, coupled with the proximity of local reserves, have combined to create producer initiatives to build bypass facilities, thereby allowing customers to avoid the costs associated with utilizing Distribution's system. Customer bypass of Distribution's system is a matter of continued concern because it adversely affects both Distribution and its other customers that have no viable alternative to utilizing Distribution's facilities. Customers with large annual volumetric requirements are continuing to consider the installation of bypass facilities.

Q. Has the threat of bypass increased since the implementation of deregulation?

A. Yes. The threat of bypass has increased because of some customers' ability to bypass Distribution and directly contract with pipelines for other sources of gas supply. Under FERC Order No. 636 and other deregulation initiatives, interstate pipelines in Distribution's territory are no longer merchants of gas. These pipelines are actively marketing capacity for transportation service. This has created a "major pipeline" bypass threat in addition to the previously mentioned producer bypass. Distribution's large volume customers that are located near major pipelines having available transportation capacity now have more options to secure gas supplies without utilizing Distribution's facilities. Since pipelines offer high quality service and connection to a variety of sources of gas, this type

of bypass eliminates some of the service concerns that may be present in a local production bypass, thereby making bypass even more attractive.

Q. Are there other specific bypass threats that cause significant risk of load loss to Distribution?

A. Recent bypass assessments identified those customers with existing bypass facilities as well as a number of customers that are at risk to bypass. As listed in Exhibit No. 18, a total of 15 large industrial and institutional concerns have existing bypasses in place, displacing an estimated 8.3 Bcf for the twelve months ending September 2005 with an additional 3.4 Bcf at risk. Another 63 customers were judged to be "at risk" accounts due to their economic proximity to a bypass source. Of these 63 customers, 34 are considered high risk and represent 4.3 Bcf, 13 are considered medium risk and represent 1.3 Bcf and 16 are considered low risk and represent 0.3 Bcf. Total "at risk" consumption, in addition to the 8.3 Bcf of existing bypass volumes, is estimated at 9.3 Bcf based on the twelve months ending September 2005.

To further exacerbate the previously described competitive conditions relative to local production and interstate pipelines, Distribution is uniquely situated in a geographic area criss-crossed with privately-owned pipelines located within gas producing areas, resulting in even more competitive pressures due to the relative ease with which local production can be accessed through bypass connections, even when the gas supplies are not in the immediate vicinity of

customers. Examples include an extensive former interstate pipeline owned gathering system purchased by NORSE as well as a former petroleum pipeline system, the Northern Pipeline, which was converted to transport natural gas. Northern is owned and operated by Vineyard Oil & Gas and Eastern Resources. These pipelines extend throughout significant portions of our service area, including locales where a number of our largest industrial customers reside.

In addition to third party owned local production, self-help wells represent a substantial threat. In recent years, well drilling activity has again increased to a significant degree. The Pennsylvania Department of Environmental Protection issued a record number of oil and gas permits in 2005, up 32.4% from the previous year. The Northwest Regional Office issued the majority of these, including 333 drilling applications in November 2005 alone, the largest number of applications ever received by the department in any one-month period since the Oil & Gas Act of 1984. A number of these are either private wells or include royalty arrangements that result in the displacement of LDC service to one degree or another.

Q. How has Distribution responded to these competitive bypass threats, both current and potential?

A. Distribution responds to competitive situations for large incremental load opportunities that are potential bypass threats by first trying to understand the competitive threat and the associated economics. If the threat is determined to be

Q. How is Distribution currently addressing electric competition?

A. Distribution has a variety of programs targeted towards educating both customers and key influencers to encourage the efficient use of our system and to promote the benefits of natural gas. These programs are designed to encourage customers to make natural gas the fuel of choice and to encourage its use in the most efficient manner, thereby making Distribution's services more economically competitive. This result benefits the customers using these programs and indirectly benefits all customers by retaining as much throughput on the system as possible in order to control unit costs by spreading fixed costs over as many billing units as possible. In addition to energy audits, Distribution maintains key influencer programs targeted at appliance dealers, heating/plumbing contractors, builders, architects, and mechanical engineers to promote efficient gas technologies. These programs exist because of the strong influence of these trade allies on the use of natural gas and natural gas equipment by Distribution's residential and commercial/industrial customers in both the replacement/retrofit and new construction markets.

Distribution has developed a broad umbrella trade ally program, "The Energy Partnership" with the goal of building and maintaining preference for natural gas among key influencers, and thereby among Distribution's customers, in order to retain its existing sales/market share and selectively pursue opportunities for increased sales. The programs offer cooperative advertising to reinforce the benefits of natural gas (efficiency, economy and environmental).

Training is also a typical component of the program with an emphasis on safety and technical issues (equipment venting, building codes and standards, and new technologies).

The primary means by which Distribution addresses electric competition in the nonresidential marketplace is through direct interaction with architects, engineers and customers in the planning and design phases to promote the use of natural gas equipment for both traditional and innovative applications. Commercial software is used to identify and track prospective projects in the earliest phases of project development. Where beneficial to the project and economically justified, internal and external technical assistance may be utilized to provide a detailed comparative analysis to assist the customer in making an educated decision regarding fuel choice. In addition, Distribution distributes industry publications as well as publishing its own technical fact sheets related to new or beneficial gas technologies, and distributes an electronic newsletter to its largest nonresidential customers highlighting key energy efficiency and technology news.

Q. How has the load balancing service rate served in improving Distribution's system load profile?

A. Currently Distribution has seven customer accounts that are utilizing this rate. This rate has been effective in attracting high load factor or non-winter load customers, thereby improving Distribution's load profile. Many of the customers

utilizing this rate, are asphalt plants converted from an alternate fuel to natural gas.

In the past, Load Balancing Service has also been effective in Distribution's efforts to introduce new technologies that have helped several customers reduce their operating costs, thus making them more competitive in their markets.

Q. Is the transportation of natural gas continuing to be useful in retaining markets and in meeting competition?

A. Yes. Distribution recognized in the mid-1980s that its market was changing dramatically as a result of the FERC's decision to encourage competition on the interstate pipelines by relaxing the rules governing transportation of natural gas. Distribution was one of the first LDCs in Pennsylvania to offer transportation service to its major end-users. Distribution's service began in 1983 with nine end-users and 1.6 Bcf of transportation throughput and has evolved in 2006 to include approximately 1,200 end-users and approximately 18.2 Bcf of transportation throughput.

Transportation service has historically been offered to the LIS, LVIS, IVIS, SVIS and Comm/PA customers and most recently to residential customers. As previously stated, negotiated transportation rates have been used to meet specific bypass threats. Other rate schedules designed so that bypass customers and transporters pay their fair share of costs are the Bypass (BP), Standby (SB) and Priority Standby (PSB) rate schedules – the BP rate to recover nongas system

costs that Distribution incurs based on the maximum winter months' usage by a customer, the SB and PSB rates to provide some level of recovery of gas costs for backup sales service for customers who are transporting.

Q. Are you familiar with the performance criteria for electric and gas companies that were adopted by the Commission, under Section 523(b) of the Public Utility Code in an order entered on January 31, 1989, at Docket No. L-880039?

A. Yes. I am familiar with the Commission's performance criteria applicable to gas and electric utilities with regard to energy supply alternatives.

Q. The first criteria relates to the dissemination of information:

"(1) Information. At least twice annually, utilities should provide customers with information on specific means of utilizing their energy services more effectively and efficiently. Topic areas should include insulation, lighting efficiencies, appliance efficiencies, conservation practices, load management techniques or other relevant information that informs the customer of the efficient use of energy." What does Distribution do to provide its customers with information on the efficient use of energy?

A. Distribution does provide information regarding the effective and efficient use of natural gas. For example, within Distribution's communication plan, information on safety and energy savings tips is provided to customers. This information is provided in the form of bill stuffers, brochures, and is offered on our website. Additional information is provided to customers by Distribution's Energy Partnership Co-op advertising program with appliance dealers and builders. And

this past year, Distribution implemented a special program with our Energy Partner network to provide customers with vendor discounts for energy conservation related products and services.

Q. How does Distribution inform commercial, industrial and public authority customers of means for the efficient use of energy?

A. Distribution provides technical information regarding the effective use of energy to its non-residential customers in a number of ways.

Some examples include Gas Technology, a magazine that is sent to select commercial, industrial and public authority customers based on their potential to utilize the technologies featured in a particular issue. This publication is provided to our customers several times per year and features information on existing and new HVAC and process technologies. Techline is another source of energy information provided to select non-residential customers, based on technology application. This bulletin-type publication features technical/marketing information on advanced technologies such as ceramic radiant tubes, distributed generation, and waste reduction/management.

Q. Does National Fuel provide information to commercial, industrial and public authority customers in any forms other than these publications?

A. Yes. Distribution's Energy Services' personnel offer an array of technical assistance programs. For example, where applicable, Distribution provides operating cost analyses for HVAC and industrial process equipment to assist customers in minimizing fuel costs and evaluating alternatives. In addition,

where Distribution conducts an energy audit, further conservation related information and recommendations are provided.

National Fuel also provides information and advice on combustion technologies and industrial process equipment selection, which also includes feasibility analyses in areas of distributed generation, gas cooling and dehumidification.

Energy Services' personnel provide information on the various gas rates available to allow Distribution's customers to take full advantage of its rate options. This includes, for example, information on its Transportation, Load Balancing, Business Development, Bypass and Standby tariffs. In terms of electronic communications, in addition to the electronic newsletter mentioned previously, Distribution continues to enhance its website to include information on efficiency and technology.

In addition, Distribution sponsors training workshops related to best practices in industrial process use and other nonresidential natural gas applications, specifically addressing available methods to reduce fuel use and costs, improve energy efficiency, and reduce emissions. Recently, certified instructors presented seminars, developed by the Department of Energy's Office of Energy Efficiency and Renewable Energy on topics including process heating and steam system assessments. Each attendee was also provided a copy of the DOE software tools that assist in identifying major energy consuming equipment and prioritizing energy efficiency improvement opportunities.

Distribution has also actively participated in various local and regional energy conferences and community-sponsored meetings, in conjunction with a variety of organizations such as the Erie Chamber and Growth Partnership, Clarion University and its affiliated Small Business Development Center, the Northwest Regional Office of the Department of Environmental Protection, the Pollution Prevention Roundtable and the Commonwealth Community Energy Project. The focus of these efforts has been to educate nonresidential customers on energy efficiency and cost savings opportunities, environmental impacts, and rate options.

Q. Does Distribution engage in any programs to improve upon the performance and availability of gas-consuming appliances and equipment options?

A. Yes. Distribution engages in research, development and demonstration (RD&D) of gas-consuming appliances and equipment.

Q. What is the goal of Distribution's RD&D program?

A. The principal goal is to provide assurance that a customer's investment in gas-consuming appliances and equipment will be beneficial and that their expectations, in terms of equipment reliability, operating costs and/or environmental compliance, will be at least met, if not exceeded. In addition, development and marketing of certain products will improve Distribution's load factor, thereby allowing Distribution to recover fixed costs over a greater number of billing units, and many projects also have the potential to bring about improvements in air quality for the benefit of all persons in our service territory.

Q. Have changes in the natural gas industry research and development at the national level affected Distributions RD&D program?

A. Yes. During the period of transition and uncertainty following elimination of the mandatory FERC surcharge, the number and pace of advancements in gas technologies have lagged, especially for customer end-use technologies.

Q. Could you describe those changes?

A. Research, Development and Demonstration (RD&D) in the natural gas industry has undergone significant changes in the past six years. Prior to that, research involving long and intermediate-term commercial development of technologies was conducted through mandatory assessments at the Federal level. Although there were project advisor groups made up of various representatives of the gas industry to help direct research, there was very little real influence on the direction of those efforts.

Mandatory funding of gas industry research through the Federal Energy Regulatory Commission surcharge has been eliminated. This surcharge supported research by the former Gas Research Institute of Chicago. During this five-year transition period where this GRI research budget went to zero, the lack of gas technology development became noticeable. This is particularly true with customer end use (utilization) technologies. In general, manufacturers did not initiate new product research and development to compensate for the loss of the GRI program.

Distribution understands that basic gas industry research and applied

research for the development of technologies far from commercialization now fall under the domain of the United States Department of Energy, and other federal agencies.

Q. Has the Distribution's RD&D Program been affected by the changes at the national level?

A. Yes. Distribution's traditional RD&D program is dependent upon having a flow of new and improved technologies into our region. With the reduced levels of research funding during the transition, the quantity and quality of technology offerings have declined.

Q. How has Distribution responded to the changes at the national level?

A. To better address short to intermediate term gas technology development needs, in R-00049656 Distribution requested and the Public Utility Commission allowed the collection and funding for such projects through supplemental funding, the Delta Fund program.

Q. Describe the Pennsylvania Delta Funds RD&D Program, which has replaced the previous GRI mandatory Federal program and supplements Distribution's traditional RD&D program.

A. State regulatory commissions have established so-called Delta Funds RD&D Programs to replace the previous GRI assessments. In R-00049656, the Pennsylvania Commission approved the establishment of such a program by Distribution for utilization and operations research. The bulk of the program involves funding of national near-term applied research through not-for-profit

research entities of the new Gas Technology Institute. These include the Utilization Technology Development (UTD) group, the Operations Technology Development (OTD) group and the GTI Sustaining Membership Program (GTI-SMP.) Once the minimum annual funding commitments are made, these utilization and operations development entities provide portfolios of projects from which to voluntarily choose and fund.

In addition, Distribution has requested the flexibility to identify projects of direct local benefit to Pennsylvania customers and businesses for utilization funding, as opportunities arise.

Q. How has this change affected Distribution's RD&D program?

A. With the stabilization of the gas RD&D industry through similar alternate means of funding resources, technology development projects appear to be returning to a more active level.

Distribution, through its traditional RD&D expenditures as well as the Delta Fund program, continues to participate in worthwhile near-term end-use technologies and company operations technologies with wide ranging benefits from efficiency to safety and environmental stewardship.

Distribution supports external research in cooperation with other utilities and other outside parties with a common objective. This co-funding by other entities and participating manufacturers demonstrates higher levels of support across markets and provides for greater leveraging of research dollars.

In addition, Distribution also supports internal research, where

opportunities exist within industries or technologies specific to our customer base that may not carry sufficiently broad applicability outside of our service territory to generate projects on a national level.

Q. What are some examples of RD&D projects in which Distribution has participated?

A. Examples of projects include: advanced burner systems, distributed generation, combined heat and power systems, advanced metal melting and sintering processes, foodservice equipment enhancements, gas engine drive- air compressors, manufacturing facility river water pumps, sewage treatment plant pumps, ice rink compressor and dehumidification; fuel cells; instantaneous water heaters, gas booster water heater; patio heaters, high-efficiency space heaters for retrofits, and microturbines.

Q. Are any changes proposed in Distribution's overall RD&D program?

A. Yes. Since establishment of the Pennsylvania Delta Funds RD&D Program in April 2005, Distribution has been participating with the GTI and others to get the program underway. Distribution intends to continue to allocate funds to specific national, broad-based projects beneficial to Distribution and its customer base as GTI establishes this fledgling program. We are looking forward to having increased levels of attractive proposals for research projects to review as membership expands. In addition, Distribution continues to participate in and solicit new RD&D opportunities specific to local needs. However, should residual RD&D funds remain following allocations to selected GTI and local

projects, Distribution proposes to utilize all or a portion of these residual funds to support additional customer outreach programs to improve energy efficiency and conservation, with an emphasis on residential and small business customers.

Q. Do you see any potential impediments to the overall natural gas and energy RD&D program?

A. Distribution believes that current programs available through local and national organizations will adequately address future gas equipment development needs as technology offerings improve. These investments, in conjunction with a concerted effort to educate and assist customers to utilize energy in the most efficient manner, will maximize the benefits of these funds to all ratepayers.

Q. What level of RD&D expense do you project for the future test year?

A. Distribution expects that the future test year RD&D expense will be $911,811 (reference Exhibit No. 104 Schedule 1 Page 2 Research and Development expense of $34,869 and Exhibit No. 104 Schedule 2 (GTI) expense of $876,942)). This level of expense is based on an evaluation of the projects that Distribution is currently working on.

Q. The second performance criteria of Section 523(b) relates to energy surveys:

"(2) Energy Surveys. Class A utilities should offer on-site energy surveys to the residential, commercial, and industrial classes on an ongoing basis. Surveys should be conducted by trained personnel and the results of the survey, upon written request of the customer, be delivered in writing with a clear explanation of the resulting components."

Q. Does Distribution provide energy surveys for customers?

A. To the extent a competitive threat exists, Distribution performs detailed energy surveys. These surveys pinpoint the opportunities to use gas in a more efficient manner or in cases where alternate fuels are consumed particular emphasis is placed on a strategy to gain that potential load. In addition, Distribution continues to provide numerous surveys to conserve energy usage under the Low Income Usage Reduction Program and qualifying customers under the Low Income Residential Assistance Program. As described in the testimony related to our RD&D program, Distribution is also proposing to further broaden our existing energy conservation survey and outreach efforts, particularly for residential and small businesses customers.

Q. The third performance Criteria of Section 523(b) pertains mainly to electric utilities. However, has Distribution sought to encourage distributed generation and small power production facilities?

A. Yes. Distribution has encouraged development of distributed generation. For example, Distribution offers load balancing rate schedules that are designed to promote both year-round high-load factor use and off-peak use of gas. These rates cover both sales and transportation of gas and reduce the effective cost of gas service for customers that utilize technologies with high load factors such as distributed generation.

Distribution also offers direct assistance in the form of technical/economic feasibility analyses for customers considering employing

distributed generation at their facilities. Distribution continues to monitor the progress in packaged distributed generation equipment.

Q. The fourth Performance Criteria of Section 523(b) relates to least-cost planning:

"(4) Least-Cost Planning. Gas and electric utilities should actively pursue a least-cost strategy by acquiring and developing the resources necessary to effectively meet their customers' future energy needs, consistent with established availability and reliability criteria. Utilities should make a reasonable effort to promote the utilization of practical and economical energy conservation and demand management through cost-effective programs."

Please discuss Distribution's least-cost planning efforts.

A. With regard to Distribution's least-cost gas procurement practices, I note that this Commission annually engages in a thorough and detailed review of Distribution's purchased gas costs, 1307(f), to ensure that Distribution follows a least-cost gas procurement policy. Distribution's least-cost procedures are well documented in such proceedings and I will not attempt to explain them here. My testimony will concentrate on Distribution's efforts for energy conservation and demand management.

All of Distribution's marketing activities responsive to the first three performance criteria promote conservation and the wise use of energy and Distribution's system. In addition, Distribution has proposed various rate schedules with rate designs that encourage demand management by customers. The Load Balancing Service Rate schedules were approved by the Commission

April 6, 1989 (Docket R-881163) and encourage customers to use more gas in the summer and less gas in the winter, thereby improving Distribution's load factor. Similarly, Rate Schedule BP, for bypass service, encourages customers with bypass facilities to use gas from Distribution at a relatively high load factor, that is, use comparable volumes of gas during the non-heating season in relation to the volumes of gas used during the heating season.

Q. The fifth Performance Criteria of Section 523(b) deals with development of a reliable customer database:

"(5) Evaluation. Class A utilities should demonstrate progressive work regarding development of a reliable customer database including but not limited to:

(i) End-use applications for all classes of customers in terms of energy and demand.

(ii) Customer behavior with regard to the decision-making process.

(iii) The impact of program decision or strategies and how they affect the overall planning process."

Explain Distribution's efforts concerning development of a reliable customer database.

A. Distribution's ongoing database development of customer end-use applications has focused on the larger customers and those that elect to transport third party supplied natural gas.

The Energy Market Monitor ("EMM") customer database was designed to provide Distribution with a detailed monitoring system that is maintained by the Rates and Regulatory Affairs Department in conjunction with Energy Services and other departments. The EMM system provides substantial information on the large-volume accounts. Data such as equipment, dual fuel capabilities, base load, firm consumption, contact names and meter/regulator information are stored to provide both the customer and Distribution with detailed reports. Customer data can also be summarized across various data fields to provide better management information.

Distribution has the ability to report volumes on a sales, transportation and total throughput basis, or on an individual rate schedule basis. In essence, our goal is to gain a better understanding or our customers so that we may better serve them. Data integrity for the EMM system is maintained through ongoing system integration and maintenance.

Lastly, Distribution has developed a variety of different systems upon which transportation service is based and through which customers and third party suppliers can access account information and actively, efficiently and effectively administer their natural gas supply deliveries and monitor usage.

Q. What is Distribution doing to better understand its markets and the associated risks and opportunities?

A. Distribution conducts market surveys to monitor market shares and energy preference levels, understand customer energy perceptions and decision-making

processes, and collect customer demographic/building characteristics data. This survey is used in quantifying market risk and opportunity and directing its marketing/advertising message to the proper decision maker.

Q. The sixth Performance Criteria of Section 523(b) relates to natural gas co-firing coal:

"(6) Natural Gas Co-Firing. Electric utilities should explore the potential for increasing capacity and output at coal-fired generating stations through gas co-firing."

Explain Distribution's efforts with regard to natural gas co-firing.

A. There are currently no coal-fired electric generating facilities located in Distribution's service territory.

Q. Does this conclude your direct testimony?

A. Yes, it does at this time.

DIRECT TESTIMONY OF NANCY J. TAYLOR

Q. Please state your name and business address.

A. My name is Nancy J. Taylor. My business address is 1100 State Street, Erie, Pennsylvania 16501.

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

A. I am employed by National Fuel Gas Distribution Corporation ("National Fuel" or the "Company") as Senior Manager - Quality Assurance.

Q. Summarize your educational and professional background.

A. I graduated from Towson State University in 1978 with a Bachelor of Science Degree in Business Administration. I joined National Fuel in 1978 as a management trainee in the Consumer Business Department and have held a variety of positions prior to assuming my present responsibilities in the Quality Assurance Department.

Q. Please describe your responsibilities with National Fuel.

A. I am responsible for National Fuel's Quality Assurance, Outreach and Education, and Energy Management Departments in Pennsylvania. These departments administer the Company's Universal Service and Energy Conservation Programs including the Low Income Residential Assistance (LIRA) program, the Low Income Usage Reduction Program (LIURP), the Customer Assistance and Referral Evaluation Services (CARES) program, the Neighbor for Neighbor Heat Fund, Outreach and Education activities, and the PUC complaint response and resolution function.

DIRECT TESTIMONY OF NANCY J. TAYLOR

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

A. Yes.

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

A. The purpose of my testimony is to describe the current aspects of the Company's LIRA program.

Q. Please describe the recent history of the Company's LIRA program.

A. On October 1, 1999, National Fuel submitted to the Commission its restructuring filing pursuant to the Natural Gas Choice and Competition Act (the "Act"). The restructuring filing included information concerning the Company's universal service programs. The Company explained that it was continuing to enroll participants in its LIRA program toward a goal of 5,000 participants as established in a previous settlement. The Company was not proposing to further expand the LIRA program at that time.

On March 17, 2000, National Fuel, the Office of Trial Staff ("OTS"), the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA") and other parties filed a proposed partial settlement of the restructuring proceeding ("Restructuring Settlement"). The Restructuring Settlement, among other things, called for the Company to file with the Commission a proposal to provide adequate and ongoing funding of the LIRA program at the 5,000 total customer level and address the

expansion of the program. On February 15, 2002, the Company filed a petition (Docket No. P-00021945) with the Commission seeking authority to expand and revise the LIRA program and seeking approval of a funding mechanism for recovery of the current bill shortfall resulting from the LIRA rate discount associated with the continuation and expansion of the program.

Q. What was the outcome of that petition?

A. On March 28, 2002, the Commission issued an Order granting the Company's petition to expand the LIRA program from approximately 5,000 to 8,500 participants. The Order also granted approval to initiate several program design changes including the initiation of a variable rate discount, the extension of the arrearage forgiveness period from 12 to 24 months, and the elimination of the conservation credit. Further, the Company was granted authority to establish a rider for non-LIRA residential customers to fund the additional costs associated with the expansion and approved program design changes. The approved program design changes were then implemented in April of 2002.

As a result of settlement discussions in Case No. R-00038168, the Company filed on September 12, 2003, a "Stipulation with Regard to LIRA Program Issues and LIRA Rider." This stipulation addressed three LIRA related program issues involving procedures for participant income re-verification, the

arrearage forgiveness component of LIRA and the LIRA cost recovery rider. On August 26, 2004, the Company filed tariff revisions proposing the elimination of the limit on LIRA enrollment, thus allowing the Company to continue to fulfill its obligation under the Act to provide a customer assistance program that is adequately funded on an ongoing basis that meets the needs of payment-troubled low-income customers within its service territory. The Company also proposed a methodological change in how the LIRA discounts are computed, intended to address affordability concerns raised by the Commission's Bureau of Consumer Services relative to larger household sizes. The change involves specific recognition of higher average annual gas consumption among larger households in the computation of the LIRA rate discounts. At Public Meeting of March 23, 2005, the Commission adopted an Order that approved the Stipulation in Settlement that included the proposed revisions to the LIRA program. On May 11, 2005, the Company submitted its revised Universal Service and Energy Conservation Plan to the Commission's Secretary which included the changes approved in the Settlement. On August 11, 2005, the Commission adopted a Tentative Order approving the Company's' Universal Service and Energy Conservation Plan with modifications. Following review of comments by various parties on

the Tentative Order, the Commission issued a Final Order on December 15, 2005, approving the Company's Plan as filed.

Q. Please describe the present LIRA related account status.

A. As of May 1, 2006, 11,085 customers are actively enrolled in the LIRA program. Of those customers, approximately 11% are two months or more behind in their payment. Customers are distributed among the eight service classes according to their income and household size. The distribution, as of May 1, 2006, is as follows:

10%	2061
20%	904
30%	1376
40%	1305
50%	1379
60%	3277
70%	782
80%	1

Q. Has the Company evaluated how enrollment is meeting the level of need in its service area?

A. The Company, in its last rate filing suggested eliminating the cap on program enrollment, and has since done so. As a result, increased enrollment has occurred over the last year, with current enrollment of 11,085. The cap was previously set at 8,500. A revised needs assessment follows:

LIRA Needs Assessment
April 2006

1. Total - Identified Income Level 1 Ratepayers on CIS	**18,963 (a)**
2. Total - Low Income Ratepayers Identified on CIS	**30,311 (b)**
3. Total of Low Income Ratepayers Minus Level 1 Ratepayers	**11,348 (c) (Lines 2-1)**
4. Payment Troubled LIHEAP recipients (40% of Line 3)	**4,539 (d)**
5. Total Identified Payment Troubled Ratepayers in NFG service area	**23,502 (e) (Lines 1+4)**
6. 50% of Line 5	**11,751 (f)**
7. 67% of Line 5	**15,746 (g)**

Notes:

(a) Identified Income Level 1 ratepayers are those who have entered into payment arrangements and who are therefore considered payment-troubled. Income Level 1 ratepayers are those between 0 and 150% of the Federal Poverty Level.

(b) "Total of Low Income Ratepayers" includes identified Level 1 ratepayers plus all those who received LIHEAP.

(c) 11,348 represents those ratepayers who are not identified as Level 1 by National Fuel, but who received LIHEAP.

(d) The Commission's Investigation of Uncollectible Balances (Docket No. I-900002) found that 40% of the Commonwealth's low-income households are payment-troubled. (Pennsylvania Bulletin, Vol. 29, No. 19, May 8, 1999)

(e) This is a total of all Level 1 ratepayers plus those who received LIHEAP who may be payment-troubled (18,963 plus 4,539).

(f) The Pennsylvania Bulletin, Volume 29, Number 19, states ". . . current participation rates for government programs such as food stamps and LIHEAP are around 50%. We would not expect every payment troubled household who is eligible for CAP to apply for enrollment."

(g) National Fuel believes that a participation rate of 2/3 may be more appropriate in its service territory based on its recent experience in reaching the original enrollment cap nearly a year ahead of schedule. Participation rates may be higher since Pennsylvania Bulletin, Volume 29, Number 19 was published in 1999 due to increasing natural gas commodity costs.

(CIS data as of April 2006)

The needs assessment submitted in April 2005 demonstrated a need of between 10,131 and 13,576 potential participants. Based on both of these assessments, the Company is operating the program and enrolling customers at the appropriate level. Currently, the Company is undergoing an evaluation of the Universal Services Programs by an independent evaluator as required by Title 52 Chapter 69.265(10) of the Pennsylvania Code. The evaluation is due to the Commission in August 2006.

Q. Please discuss current intake procedures.

A. Potential applicants are identified by National Fuel employees during customer contact such as arrangement requests. During those conversations, the employee will take a statement of the customer's income. If they appear to be eligible for the program, a direct referral is made and the customer is sent an invitation to apply. Currently the application process is completed by an outside vendor who gathers the required information and proof of income, then using National Fuel's information system, enrolls the customer on the appropriate LIRA rate.

Q. Is the use of an outside vendor a new practice?

A. At the beginning of 2006, the Company recognized that the program had grown to a size where we could not adequately administer the program and undertake the day-to-day intake operation. Referrals to the program have continued steadily,

resulting in substantial account monitoring responsibilities for National Fuel staff.

Q. How was the vendor selected?

A. The Company used a bid process to select the vendor. The Request For Quotation was made to eight potential vendors. Of the three responses, Teletron Corporation was selected as the vendor.

Q. What services are they providing?

A. In addition to processing the applications and enrolling customers in the program, they will follow a similar procedure to reverify customers on LIRA rates to assure their continued eligibility. They will also perform payment reminder calls to participants enrolled in the program. The payment reminders help to reinforce the program features education that each customer receives at enrollment so that they completely understand the benefits of program enrollment such as timely payment and resulting arrearage forgiveness. The Company monitors the vendor's activities on a daily basis to assure proper procedures are followed.

Q. What is the Company's role in administering the LIRA program?

A. The Company will continue to assist customers who are on the special rates, answering their questions, monitoring their accounts and their payment amounts, following up with collection action if necessary and making any adjustments as needed to assist the participants. The company personnel will also continue to assist

the LIRA customers with LIHEAP applications, along with other social services available in the community. LIRA customers will continue to receive conservation education and referral to LIURP, as appropriate. Emphasis on conservation helps drive home the customers' responsibility to control usage to further control their monthly bills.

Q. Does the Company have any plans to make any changes to the LIRA program?

A. The Company plans no major changes to the LIRA program. As stated earlier, an evaluation of the program is currently under way. Recommendations may come from that study that the Company may consider for implementation. As always, minor improvements to program procedures may occur in the course of daily business to better serve the participants.

Q. Does this conclude your testimony?

A. Yes, it does.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
DIRECT TESTIMONY OF STEVEN WAGNER

Q. Please state your name and business address.

A. My name is Steven Wagner and my business address is 6363 Main Street, Williamsville, New York 14221.

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

A. I am employed by National Fuel Gas Distribution Corporation (Distribution) as Vice President.

Q. What is your educational background and work experience?

A. I attended St. Bonaventure University where I majored in Accounting and received a BBA degree in 1975. Upon graduation, I accepted a position with Price Waterhouse (now PricewaterhouseCoopers) in their Buffalo, New York office. After leaving Price Waterhouse in 1984 as a Senior Manager in their Tax Department, I accepted a position with National Fuel as Manager of Corporate Taxes. I was promoted to Assistant Treasurer in April 1991 and to Vice President in April 2004. As head of the Tax Department, I have final responsibility for all tax matters affecting National Fuel Gas Distribution Corporation and its affiliates.

I am a Certified Public Accountant and a

member of the American Institute of CPAs, as well as the state CPA societies of New York, Pennsylvania and Texas. I was a member of the Advisory Board for the State University of New York at Buffalo's Graduate Tax Certificate Program and served as a faculty member. In addition, I am past Chairman and a member of the Tax Committee of the American Gas Association and a member of the Tax Committee of the Interstate Natural Gas Association of America. I have also served as President of the Niagara Frontier Chapter of the Tax Executives Institute.

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

A. Yes. I testified before this Commission on behalf of the Company in Docket Nos. R-00049656, R-00038168, R-953299, R-942991, R-932548, R-911912, R-901670, R-891218, R-870719 and R-850287.

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

A. Yes. I have submitted testimony to the New York Public Service Commission and the Federal Energy

Regulatory Commission on behalf of the Company and its regulated affiliate in various rate proceedings.

Q. What are the subjects of your testimony?

A. In this testimony, I address the ratemaking effects of the Company being included, along with affiliates, in a consolidated federal income tax return filed by its parent company, National Fuel Gas Company.

Q. Please explain the Company's position on ratemaking adjustments which take into consideration the tax effects of losses of affiliates, so-called consolidated tax adjustments (CTAs).

A. The Company believes that CTAs are improper and the reasons are summarized later in my testimony. However, the Company has included a consolidated tax adjustment in this proceeding because it is clear that such an adjustment will be made by the Commission given its past policy in this regard.

Q. What is the magnitude of the Company's CTA calculation?

A. The Company's CTA calculation results in a

reduction in recoverable federal income tax expense in this proceeding of $82,000. The calculation is summarized on Exhibit 107, Schedule 2.

Q. Please explain the Company's CTA calculation.

A. The Company's calculation of the CTA in this case follows the so-called modified effective tax rate method previously adopted by the Commission in prior cases. The calculation employs a three-year average of the most recent historical tax losses of certain nonregulated affiliates of the Company and allocates a proportionate share of this "benefit" to the Pennsylvania Division of Distribution. A three-year average of historical tax losses is used as a proxy for the tax losses that are expected to be incurred during the period in which rates set in this proceeding will be in effect. As such, only companies with continuing operations that are expected to generate tax losses in such future period are included in the calculation of the CTA. The statutory federal tax rate of 35% is used to calculate the tax benefit of such losses.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
DIRECT TESTIMONY OF STEVEN WAGNER

Q. Please identify which affiliates of the Company are included in the calculation of the CTA and explain the rationale for this treatment.

A. As noted earlier, a 3-year historical period is used in the determination of the CTA as a proxy for tax losses that are expected to occur during the period in which rates set in this proceeding will be in effect. Accordingly, National Fuel Gas Company, Horizon Energy Development, Horizon Power and Horizon LFG are included in the calculation of the CTA since their historical operations are representative of those that are expected to occur in the future. Thus, their historical tax losses are used as a proxy for the future.

Q. Please identify which affiliates of the Company are excluded from the calculation of the CTA and explain the rationale for this treatment.

A. Seneca Independence Pipeline Company and Niagara Independence Marketing Co. are excluded from the calculation of the CTA since inclusion of their historical tax losses in the calculation of the CTA would not be representative of the future.

Q. Please explain the facts surrounding Seneca

Independence Pipeline Company.

A. Seneca Independence Pipeline Company (SIP) was a general partner in the proposed Independence Pipeline project. The project had proposed to construct and operate a 400-mile interstate pipeline system, which would transport natural gas from Defiance, Ohio to Leidy, Pennsylvania. In July 2002, the Federal Energy Regulatory Commission vacated the certificate that permitted the construction and operation of the proposed pipeline. The project was abandoned by National Fuel during fiscal 2002 and the vast majority of costs associated with this project were written off for tax purposes during fiscal 2003. SIP was dissolved in February 2004. SIP's tax loss for fiscal 2004 is excluded from the CTA calculation because the use of such historical information would not be representative of the future.

Q. Please explain the facts surrounding Niagara Independence Marketing Co.

A. Niagara Independence Marketing Co. (NIM), which was never engaged in an active business, was dissolved in March 2004. NIM's tax loss for

fiscal 2004 is excluded from the CTA calculation because the use of such historical information would not be representative of the future.

Q. Please summarize the Company's objections to consolidated tax adjustments.

A. Fist of all, the Company believes it is an unfair ratemaking practice to provide customers, in calculating income tax expense, with the tax effects of expenses that are incurred by nonregulated affiliated companies when such expenses are not paid by Distribution's ratepayers. When the tax effects of losses of nonregulated companies are used to reduce the federal income tax expense of Distribution for ratemaking purposes, shareholders are deprived of the tax effect of expenses that are funded by them. Such a result is a violation of National Fuel Gas Company's intercompany tax agreement (Exhibit No. 7, Schedule 2)

Moreover, consistency would require the Commission to allow a higher revenue requirement in the future when nonregulated companies experience taxable income if an adjustment to

Distribution's income taxes is made in this proceeding. The intercompany tax agreement requires that the tax effect of the tax losses of nonregulated companies be preserved for later use by such companies. In order for the tax effect of the loss to be preserved, consistency requires the Commission to allow Distribution to recover an increased amount of income tax in the future. This additional recovery will be necessary to pay the taxes to the federal government, on behalf of the nonregulated companies, that would have been avoided if the tax effects of the nonregulated companies tax loss carryforwards had not been flowed through previously to Distribution's ratepayers. Thus, the effect of making a CTA in the current proceeding is to reward existing ratepayers at the expense of future ratepayers.

Finally, any method of providing Distribution's customers with the "benefits" of tax losses of affiliated companies would run the risk of violating the normalization provisions of Internal Revenue Code.

Q. Please explain how a consolidated tax adjustment

could violate the Internal Revenue Code normalization rules.

A. Where the tax losses of affiliates are used to reduce the federal income tax expense of a regulated utility, such as Distribution, but the expenses and assets of such affiliates themselves are not considered in the utility's rate-setting process, as is the case with a consolidated tax adjustment, a fundamental ratemaking inconsistency occurs. It is this inconsistency which appears to be a violation of the normalization rule under Code Section 168(i) (9) (B), which requires the use of consistent assumptions in the determination of ratemaking tax expense and rate base.

Q. What are the tax consequences of a violation of the normalization rules?

A. If a normalization violation occurred, Distribution would be denied the right to claim accelerated depreciation for federal and state income tax purposes which would result in an increase in future rates for its customers.

Q. Does this conclude your testimony?

A. Yes.

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

Q. Please state your name and business address.

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

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I have sponsored Statement No. 1 and the associated Exhibit No. 4 Schedule 2 (Uncollectibles) page 5.

Q. What is the purpose of your testimony?

A. I will be describing the calculation of the uncollectible accounts expense.

Q. What do you expect the total uncollectible expense to be for the twelve months ending January 31, 2007?

A. I project the total uncollectible accounts expense for the twelve months ending January 31, 2007 to be $8,437,198.

Q. How was the $8,437,198 of uncollectible accounts expense determined?

A. The $8,437,198 of projected net write-offs was based upon the factor calculation of uncollectible accounts expense as presented in Exhibit No. 104 Schedule 2 (Uncollectibles), page 6 and the development of the uncollecible accounts expense for the twelve months ending January 31, 2007 as presented in Exhibit No. 104, Schedule 2 (Uncollectibles), page 5.

Q. Please describe Exhibit No.104, Schedule 2 (Uncollectibles), page 7.

A. Exhibit No.104, Schedule 2 (Uncollectibles), page 7 sets forth data utilized for the factor calculation of uncollectible accounts expense. This method has previously been presented by Distribution. I have utilized a

ratio of net write-offs to gross revenues. Two years of data have been utilized in the development of the factor calculation. Gross revenues for the period February 2003 through January 2005, gross write-offs and recoveries for the period February 2004 through January 2006 were employed in the computation.

Q. Why do you use different two-year periods for gross revenues and for gross write-offs?

A. The period used for gross write-offs is one year later than the period for gross revenues. I used the later period for gross write-offs in order to match the write-offs more closely with the gross revenues associated with them. The one-year difference reflects the fact that, as explained in Exhibit No. 16:

> "Unpaid finals are determined to be uncollectible and are written off to bad debt approximately three hundred sixty five (365) days after the mailing of the final statement, or three hundred forty three (343) days past due."

Q. Please explain Exhibit 104, Schedule 2 (Uncollectibles), page 6.

A. Exhibit 104, Schedule 2 (Uncollectibles), page 6 sets forth the base uncollectible accounts expense for the twelve months ending January 31, 2007 as $8,437,198, based upon the two-year average write-off rates. The base uncollectible allowance is calculated by applying the write-off factor to the forecasted sales and transportation revenues. This yields a base uncollectible amount for the twelve months ending January 31, 2007 of $8,437,198.

Q. Has the use of three years of data produced an adequate level of uncollectible accounts expense in the past?

A. No, it has not. In the past, Distribution's practice has been to use the level of expense established in rate cases as the annual accrual for recovery of uncollectible accounts expense. Under the reserve method of accounting for uncollectible accounts expense, a reserve is established on the balance sheet to reflect the expected level of uncollectible accounts expense over the forthcoming fiscal year. Over the course of the fiscal year, the reserve is increased by the amount of the expense accrual and decreased by the actual level of write-offs net of recoveries. Under this accounting methodology, if actual net write-offs exceed the expense accrual, the reserve decreases. Conversely, if the expense accrual exceeds actual net write-offs, the reserve increases.

Periodically, Distribution, in conjunction with its independent auditors, reviews the level of the reserve for uncollectible accounts expense to make certain that it represents a reasonable estimate of the level of net write-offs over the forthcoming fiscal year. On more than one occasion in recent years, Distribution has had to adjust the reserve to increase it to the expected level of net write-offs. Such adjustments are effected by increasing the level of the accrual for uncollectible accounts expense and reducing earnings by the same amount. Such adjustments have become necessary because the level of annual accrual for uncollectible accounts expense, which has been based on the

ratemaking allowance for uncollectible accounts expense, has been significantly less than actual net write-offs.

For example, most recently, in September 2005, the end of the 2005 fiscal year, Distribution booked an additional $5.6 million to uncollectible accounts expense in order to restore the level of the uncollectible accounts reserve to a reasonable level. Also, a $2.0 million adjustment to earnings occurred in May 2002.

I note also that, although the reserve method of accounting would permit Distribution to reduce the reserve and book the reduction in the reserve to increase earnings if the annual expense accrual exceeded annual net write-offs, that has not happened.

I am not providing this information in this proceeding to make any claim for past inadequacies of the levels of the allowances in rates for uncollectible accounts expense, although the levels allowed clearly have been inadequate. Instead, I am suggesting that the Commission should recognize that the method that has been used in the past has consistently produced an inadequate level of expense and that it should no longer be used. I am proposing only a modest change in the method for calculating uncollectible accounts expense for ratemaking purposes, to base the uncollectible accounts expense ratio to be applied to pro forma revenues at proposed rates, be modified to use two, instead of three, years of data. This change will cause the calculation to reflect more current circumstances in Distribution's service territory.

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

Q. Do you sponsor any other exhibits related to the twelve months ending January 2007?

A. Yes, I also sponsor Exhibit No. 116.

Q. Does this conclude your testimony regarding the twelve months ending January 31, 2007?

A. Yes, at this time.

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

Q. Please state your name and business address.

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

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have sponsored Statement No. 2 and the associated Exhibits supporting the historic test year, the twelve months ended January 31, 2006.

Q. What is the subject of Statement No. 102?

A. Statement No. 102 will relate to the overall requested increase in revenue requirement, adjustments to cost of service items and rate base for the future test year ending January 31, 2007, as well as various miscellaneous exhibits that address the Commission's regulations.

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

A. I am responsible for the information submitted in the following Exhibits relating to the future test year, the twelve months ending January 31, 2007:

Exhibit No. 102 Schedule 1 and 2

Exhibit No. 104 Schedule 1 and Schedule 3

Exhibit No. 104 Schedule 2 Pages 1 through 4, 8 through 12, and 15 through 31.

Exhibit No. 106 Schedule 1

Exhibit No. 108 Schedules 1 – 3

Exhibit No. 113

Q. Please refer to Exhibit No. 102. What is shown in this Exhibit?

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

A. Exhibit No. 102 Schedule 1 contains National Fuel Gas Distribution Company's ("Distribution's") responses to several regulations including Section 53.52 (b) 2 which requests and operating income statement of the utility.

Exhibit 102 Schedule 2 is a Statement of Income at Present and Proposed Rates for the Pennsylvania Division for the twelve months ending January 31, 2007. Provided in this Exhibit is the projected rate of return at present rates for the twelve months ending January 31, 2007, proforma with ratemaking adjustments at present rates and proforma with ratemaking adjustments at proposed rates for the year ending January 31, 2007. Column 1 of this exhibit reflects the normalized twelve months ended January 31, 2006 operating revenues, operating-revenue deductions, income taxes, and utility operating income for the Pennsylvania Division of Distribution.

Column 2 presents ratemaking adjustments required at present rates. Column 3 shows the rate year operating revenues, operating revenue deductions, income taxes and utility operating income for the Pennsylvania Division of Distribution for the year ending January 31, 2007, at present rates. Column 4 shows the revenue requirement increase necessary to achieve a fair rate of return. The various exhibits in support of these amounts are identified in Column 6.

Q. Please refer to Exhibit No. 104. What is shown in this Exhibit?

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

A. Exhibit No. 104 Schedules 1 – 8 shows the Operation and Maintenance Expenses for the twelve months ending January 31, 2007 as projected and annualized, detailed by elements of cost.

Q. Why have you shown expenses by cost elements?

A. As explained in Statement No. 2, cost elements are similar Operation and Maintenance Expenses categorized together. This is the same procedure followed by Distribution in its last several rate case presentations.

Q. Please explain Exhibit No. 104 Schedule 1.

A. Exhibit No. 104 Schedule 1 Page 2 represents annualized Operation and Maintenance Expense for January 31, 2007. Column 1 shows the normalized expenses (as summarized on Exhibit No. 4 Schedule 1 Page 2 Column 3) by cost element which totals $X. Column 2, totaling $X, sets forth ratemaking adjustments to the expenses as referenced in Exhibit No. 104 Schedule 2. Column 3, totaling $X, sets forth the ratemaking adjustments to expenses due to inflation as outlined in Exhibit No. 104 Schedule 2 (Inflation) Page X. Adding Columns 2 and 3 to Column 1 produces $X as shown in Column 4, which is the total Operation and Maintenance Expenses, as adjusted at present base rates, for the Pennsylvania Division for the twelve months ending January 31, 2007.

Q. Please refer to Exhibit No. 104 Schedule 2 (Labor) Page 1, and explain the adjustment to Labor Expense for the twelve months ending January 31, 2007.

A. Exhibit No. 104 Schedule 2 (Labor) Page 1 is the summary of the Labor Expense by category. Labor Expense is composed of Pennsylvania Division labor, labor borrowed from Distribution's New York Division (New York), and labor borrowed from National Fuel Gas Supply Corporation (Supply). The first column shows that for the annualized twelve months ended January 31, 2006, the Pennsylvania labor charged to Operation and Maintenance Expense is $14,333,960, the labor borrowed from New York is $3,464,365 and that the labor borrowed from Supply is $1,294,598 for a total of $19,092,923 (reference Exhibit No. 4 Schedule 2). The adjustments of these components are found on the remaining pages in Exhibit 104 Schedule 2 (Labor).

Q. Please explain the annualization as found in Exhibit 104 Schedule 2 (PAD Labor) Page 2.

A. Exhibit 104 Schedule 2 (PAD Labor) Page 2 annualizes the salaries and wages for the employees of the Pennsylvania Division. Column 1 shows gross annualized labor at January 31, 2006 (reference Exhibit No. 4 Schedule 2 (PAD Labor) Page 2).

The normalized clerical payroll of $2,698,047 was increased by 2.75% to reflect the percentage increase in salaries effective January 1, 2007 which calculates to $2,772,243 annually. The 2.75% applied at January 1, 2007 is a proxy based on the actual increase at January 1, 2006.

Next, the annualized payroll for each bargaining group was increased

due to the known contractual wage agreements for the portion of payroll increases that will be effective in the first year when rates are established in this proceeding will be in effect. Local 22 will receive a contractual increase of 2.5% effective April 29, 2007. The gross wages of $3,788,646 were increased by 2.5% for 9/12th of the future test year January 31, 2007. This adjustment increases Local 22 payroll to $3,859,873. Local 2154 PA will receive contracted increases of 2.5% effective April 15, 2007. The gross wages of $4,249,698 were increase by 2.5% for 9.5/12th of the future test year ending January 31, 2007. This adjustment increase Local 2154 payroll to $4,333,842. Each union's supplemental groups wages were increased in the same manner and by the same percentages respectively.

The gross supervisory payroll of $5,908,496 was increased by 3.17% to recognize a base salary increase effective January 1, 2007. Like the clerical increase, I have used the January 1, 2006 increase as a proxy for the January 1, 2007 increase. This resulted in an annualized supervisory payroll of $6,095,795.

Next I increased the permanent part-time, summer payroll and the overtime payroll in the same manner as the union increases.

The sum of the annualized Clerical, Bargaining Groups and Supervisory, and the Other Annualized Payroll equals a total gross annualized labor cost for the twelve months ending January 31, 2007 of $19,063,185 (Column 4).

I then multiplied this total by 77.00%, (Factor A; Exhibit No. 13 Schedule 4), the portion of payroll expensed to Operation and Maintenance for the historical test year, to arrive at a Pennsylvania Division payroll Operation and Maintenance Expense of $14,678,652.

Q. Please describe Exhibit No. 104 Schedule 2 (NYD Labor) Page 3.

A. The purpose of Exhibit No. 104 Schedule 2 (NYD Labor) Page 3 is to adjust labor charges for New York Division employees providing service to the Pennsylvania Division, by annualizing the effects of a contractual wage rate increase of 2.5% that became effective February 12, 2006 and reflecting the known contractual wage increase of 2.5% effective February 11, 2007 that will be incurred during the first year that rates will be in effect. The total labor charged to the Pennsylvania Division from the New York Division was $3,464,365 as shown in column 1. This exhibit provides the adjustment of $2,595 for the remainder of the contractual February 2006 increase through February 2006, and $84,295 for the contractual February 2007 increase through January 2008 which results in a total amount of $3,551,255 for the Pennsylvania Division.

Q. Please describe Exhibit No. 104 Schedule 2 (SUP Labor) Page 4.

A. Exhibit No. 104 Schedule 2 (SUP Labor) Page 4 adjusts labor charged to the Pennsylvania Division by employees of Supply to reflect a 2.5% contractual wage rate increase to become effective April 29, 2007. The labor charges from the Supply to the Pennsylvania Division for the twelve

months ended January 31, 2006 were $1,294,598. This exhibit provides the adjustment of $20,726 for the contractual April 2007 increase through January 31, 2008. These adjustments result in a total amount of $1,315,324 for the Pennsylvania Division.

When the direct Pennsylvania Division expense labor of $14,678,652 is added to the labor from New York of $3,551,255 and the labor from Supply of $1,315,324, the result is the total annualized labor expense of $19,545,231.

Q. Please describe Exhibit No. 104 Schedule 2 (Benefits.)

A. Exhibit No. 104 Schedule 2 (Benefits) Pages 8 - 16, shows the adjustment to the Operation and Maintenance Expense of the Pennsylvania Division for employee benefits. Page 8 summarizes these adjustments. I will describe the changes found on pages 9-12 and 15-16. Mr. Bauer will address the adjustments on Pages 13 and 14.

Q. Please explain the adjustment to Group Life Insurance on Exhibit No. 104 Schedule 2 (Benefits) Page 9.

A. The Company provides Term Life Insurance and Accident, Dismemberment and Disability (AD&D) Insurance for its management and union employees. The Term Life Insurance rate is $0.161 / $1,000. This rate is effective through May 31, 2006 and will be updated in this proceeding. Management employees' coverage is 2 times their salary (as found in Exhibit 104 Schedule 2 (PAD Labor) Page 2 column (4)) and non management non

supplemental employees' coverage is $50,000 per person. Supplemental employees' coverage is $25,000 per person. The AD&D Insurance Rate is $0.025 / $1,000 and is based on the same calculation. Distribution also carries a blanket travel plan for which the premium is $339 per month. These three plans are $4,922 per month or $59,064 annually. Multiplying this gross annual by the 77.00% factor results in $45,479 to Operations and Maintenance Expense for these three plans. The Officer Life Insurance expense of $20,546 is then added for a total Group Life Insurance amount to Operations and Maintenance expense of $66,025.

Q. Please explain the adjustment on Page 10.

A. This adjustment is for hospitalization expense and as explained in Statement No. 2, hospitalization expense includes three components; health insurance, a Company provided wellness program and prescription drug coverage.

To adjust the cost of the self insurance of health benefits to the end of the future test year level of operations, I started with the level of claims not including administrative fees paid per employee per month at January 2006 of $563.94. Because I anticipate that the increase in the cost of claims paid from the twelve months ended January 2005 to the twelve months ended January 2006 will be a good predictor of the increase in claims paid from the twelve months ended January 2006 to the twelve months ending January 2007, I increased the level of claims paid as of January 2006 by 31.47% to reflect the increases in claims paid per employee per month. The

percentage is the actual level of increases experienced by the Company from the twelve months ended January 2005 through the twelve months ended January 2006. This adjustment produces an expected level of claims paid per employee per month of $741.41 at the January 2007 level of operations. I then add $35.98 per employee per month from BCBS to produce a total cost of $777.39.

In order to adjust this level of cost to the level expected to be experienced during the first year that rates will be in effect, I again adjusted the costs of the self-insured health care benefits by 15.74%. This adjustment produces a level of claims paid as of July 2007 of $858.11 ($741.41 x 1.1574). Adding the administrative costs of $35.98 per employee per month produces a total cost of $894.09.

This was then multiplied by the number of participating active employees to calculate the monthly amount. This amount is multiplied by 12 for a total of $3,680,074.

Distribution calculates annually a cost of COBRA insurance coverage, which by federal law must be made available to the Company's employees upon leaving the Company. The level of that premium for equivalent coverage will be provided when it becomes available.

Next, the Wellness Program was increased by inflation for a monthly amount of $911.

The Pharmaceutical Card System (PCS) rate per employee was

increased similar to the health insurance rate per employee. I started with the level of claims paid without administration fees per employee at January 2006 of $208.47. I anticipate that the 7.72% increase from the twelve months ended January 2005 to the twelve months ended January 2006 will be representative of the increase from the twelve months ended January 2006 to the twelve months ending January 2007 therefore, I increased the level of claims paid as of January 2006 by 7.72% to reflect the increase in claims paid per employee per month. This adjustment produces an expected level of claims paid per employee per month of $224.56 at the January 2007 level of operations. Adding the administrative cost of $0.50 per employee per month produces a total cost of $225.06.

In order to adjust to the level expected to be experienced during the first year rates will be in effect, I again adjust the costs by 3.86%. This adjustment produces a level of claims paid as of July 2007 of $233.23 ($224.56 * 1.0386). I then added the administrative cost of $0.50 to produce a total cost per employee per month of $233.73. This was multiplied by the number of applicable employees to calculate the monthly premium of $931,180.

The total annual cost for these health care programs is $4,612,165. The total annualized supervisory and weekly contributions towards Hospitalization were subtracted to arrive at a total cost of $4,421,288. This was multiplied by Factor A to calculate the amount to be charged to

Operation and Maintenance Expense of $3,404,392.

Q. Please explain the adjustment on Page 11.

A. Exhibit No. 104 Schedule 2 (Benefits) Page 11 adjusts the Pennsylvania Division Operation and Maintenance Expenses for the twelve months ending January 31, 2007 for the cost of the 401(k) Plan. The January 31, 2006 401(K) payment was increased by the payroll increases outlined In Exhibit No. 104 Schedule 2 (Labor). I then multiplied the annualized 401(k) Plan by Factor A to determine the portion to be expensed of $466,411.

Q. Please explain the adjustment on Exhibit No. 104 Schedule 2 (Benefits) Page 12.

A. This exhibit adjusts the Dental Expense Benefit provided Distribution. The gross January 2006 amount of $249,503 was increased by 7% as projected in a recent 2006 Segal Health Plan Cost Trend Survey which results in a total cost of $266,968. I then multiplied this by Factor A to determine the portion to be expensed of $205,565 which is $13,448 more than the normalized twelve months ended January 31, 2006.

Q. Please explain the adjustment to Exhibit No. 104 Schedule 2 (Benefits) Page 15.

A. Exhibit No. 104 Schedule 2 (Benefits) Page 15 adjusts the Pennsylvania Division Operation and Maintenance Expense for the cost of the Retirement Savings Account (RSA). In Exhibit No. 4 Schedule 2 (Benefits) Page 13, I calculated the average monthly labor expense by employee group by hire

year. These have been increase to represent the labor increases found in Exhibit No. 104 Schedule 2 (PAD Labor) to determine an average monthly labor expense at January 2007. Since all employees will still be at the 2% contribution level, I have applied 2% to the average monthly labor expense and multiplied this by 12 for an annual gross RSA of $27,335. I then multiplied this by Factor A to determine the portion to be expensed of $21,048 which is $14,641 more than the normalized twelve months ended January 31, 2006.

Q. Please explain the adjustment to Exhibit No. 104 Schedule 2 (Benefits) Page 16.

A. This exhibit adjusts benefit charges associated with labor charged from the New York Division and Supply to the annualized level for the twelve months ending January 31, 2007. As labor dollars from other jurisdictions are charged to the Pennsylvania Division (as outlined in Exhibit 104 Schedule 2 (NYD Labor) and (SUP Labor)), a corresponding charge is made for the associated benefits.

The New York Division benefits loading factor for 2006 is 98.3%. The normalized labor from the New York Division was multiplied by the calculated benefit loading factor to compute the normalized benefits of $3,490,884 charged from the New York Division. The normalized labor from Supply was multiplied by the Supply 2006 benefit loading factor of 88.90% to compute the normalized benefits of $1,169,323 charged from Supply.

Q. Please describe Exhibit 104 Schedule 2 (Rent) Page 17.

A. Rent expense includes space leased for the Pennsylvania Division as well as an allocation of space associated with personnel working for the Pennsylvania Division. This allocated space includes Distribution's Main Office located in Williamsville, New York. The normalized historic test year rent expense of $665,590 included known monthly rates at January 31, 2006. This calculation increases these amounts by inflation with the exception of the miscellaneous Service Centers which will no longer be an expense to the Pennsylvania jurisdiction. This calculates to an annualized expense for the twelve months ended January 31, 2007 of $673,873 or $8,283 more than the normalized historic test year.

Q. Please describe Exhibit 104 Schedule 2 (Transportation Clearing) Page 18.

A. This Exhibit outlines the changes to the Transportation Clearing Account for changes to cost elements that are outlined in the Operation and Maintenance Exhibit 104 Schedule 1 Page 2.

The Transportation Clearing Account is calculated in the same fashion as described in Statement No. 2. The clearing account is forecasted as shown in the top half of the exhibit with the specific adjustments noted and the other adjustments following the inflation adjustment. The total charges forecasted for the twelve months ending January 31, 2007 are $1,810,864.

The bottom half of the exhibit outlines the Charges Distributed from

the Clearing Account including both O&M Accounts (Accounts 401000 – 402000) and non O&M Accounts (Accounts 107000 – 426400). The amount forecasted to be charged to O&M Expense for the twelve months ending January 31, 2007 is $2,259,908.

Q. Please explain Exhibit No. 104 Schedule 2 (Telephone Clearing) Page 19.

A. The Telephone Clearing Account is used to accumulate the costs incurred to provide telecommunication services to Distribution. The account is forecasted on the upper half of the exhibit and the charges distributed on the lower half. For the twelve months ending January 31, 2007 the total forecasted clearing account is $1,308,809 with $903,531 being expensed of which $371,534 is expensed to the Pennsylvania Division.

Q. Please explain Exhibit 104 Schedule 2 (Meter Shop Clearing) Page 20.

A. The Meter Shop Clearing account accumulates charges for testing and maintaining gas meters. The annualized forecast of the clearing account is $1,265,551 of which $489,919 is expensed to the Pennsylvania Division.

Q. Please explain Exhibit No. 104 Schedule 2 (PPUC) Page 21.

A. Exhibit No. 104 Schedule 2 (PPUC) projects that the annual assessment for the fiscal year July 1, 2006 – June 30, 2007 will increase over the total July 2005 – June 2006 total assessment by 24.01%.

Q. Please explain the 24.01% increase.

A. As shown in Exhibit No. 104 Schedule 2 (PPUC) Page 21 the assessment for the fiscal year July 2004 – June 2005 was $758,376. For the next fiscal

period the total assessment was $940,458. This calculates to a 24.01% increase which I have applied to the $940,458 to equal $1,166,262, a $225,804 adjustment.

Q. Is this a cost that the company can manage?

A. No. The Commission determines the PaPUC assessment. The company has no control over the amount charged by the Commission but we are required to pay the assessment. This is very similar to other costs such as the Capital Stock Tax or the Public Utility Realty Tax.

Q. Can the company manage the costs associated with the Capital Stock Tax or the Public Utility Realty Tax?

A. No, however the Commission has a mechanism that allows the company to remain whole regarding these types of costs. The State Tax Adjustment Surcharge (STA) was implemented in an Order dated March 10, 1970 which

> "permits utilities under its jurisdiction to recover portions of the Capital Stock Tax, Corporate Net Income Tax and Gross Receipts Tax and the Public Utility Realty Tax through a surcharge on rates charged to customers." (52 § 69.51)

Q. Please continue.

A. The regulation goes on to explain why the STA was instituted. In 52 § 69.52 it states,

> "Public utilities under our jurisdiction

are subject to regulation, which permits them to recover, in the form of rates, their legitimate costs, plus a fair return which compensates investors for the use of funds they have provided for the construction of utility facilities.

The new and increased taxes constitute a legitimate cost, and, unless compensated for, will reduce the return of public utilities ....."

Q. Is the assessment a legitimate cost to the company?

A. Yes.

Q. What are you proposing?

A. I am proposing an addendum to the company's current STA mechanism which would allow the company to compare the annual PaPUC assessment amount paid with the amount allowed for in this proceeding. If the amount paid were greater than the amount set in rates, a surcharge to customers would occur. If the amount paid were less than what is set in rates, the company would provide a refund to customers. Since the STA mechanism is already in place with procedures for timings and review of filings, the company would include the assessment as an additional line item. Initially, the addendum would be set at $0 when rates from this proceeding become effective around February 28, 2007. When the assessment is received in

August 2007 the company would compare the amount on the assessment to what was allowed in rates, for example the $1,166,262 that I have requested. If the amount paid is greater than $1,166,262, a surcharge would be filed with the October filing. If the amount paid were less than $1,166,262, a refund would be filed.

Q. What if a supplemental assessment is issued?

A. If a supplemental assessment is received prior to the October filing it would be included. If it were received after the October filing, the supplemental assessment would be included in the following year.

Q. Would there be any estimates in the calculation?

A. No. The amount set in rates would be known as well as the assessment amounts. A copy of the invoice could be included in the filing for verification.

Q. Please explain Exhibit No. 104 Schedule 2 (Injuries and Damages) Page 22.

A. The cost element Injuries and Damages includes claims paid by Distribution that are not covered by insurance. As shown in the Exhibit, the past three years Operation and Maintenance expense amounts are brought forward to 2007 dollars using the GDP Chain-type price index for 2004 through 2006 and the calculated inflation factor for 2007. An average of the three years in 2007 dollars was calculated to be $1,299,254. This is an increase of $725,370 from the historic test year per books amount of $573,884.

Q. Please explain Exhibit No. 104 Schedule 2 (Postage) Page 23.

A. On May 2, 2006 the postal service filed for an increase to become effective

in the Spring of 2007. Pre-sorted mail, which represents the majority of the Company's postal cost, will increase by 6.5%. I have applied this percentage increase to the normalized expense for the twelve months ended January 31,2006 of $89,153 for a calculated expense for the twelve months ending January 31, 2007 of $94,948.

Q. What if this 6.5% postage increase is not implemented by the postal authority?

A. If the postal authority does not implement the proposed 6.5%, the increase to postage should be adjusted to reflect either the actual increase implemented by the postal authority or by the inflation factor.

Q. Please explain Exhibit No. 104 Schedule 2 (ISD Clearing) Page 24.

A. The ISD Clearing account accumulates costs of providing computer technology to Distribution. Forecasted charges found in Exhibit No. 104 Schedule 1 Page 2 equals $13,381,053 of which $3,042,011 is expensed to the Pennsylvania Division Operating and Maintenance Expense.

Q. Please explain Exhibit No. 104 Schedule 2 (Contract Admin. Clearing) Page 25.

A. The Contract Administration Clearing account accumulates the costs associated with the contracting of gas supply for Distribution. Forecasted charges found in Exhibit No. 104 Schedule 1 Page 2 equal $1,680,942 of which $536,725 is expensed to the Pennsylvania Division Operation and Maintenance Expense.

Q. Please explain Exhibit No. 104 Schedule 2 (Customer Billing Clearing) Page 26.

A. The Customer Billing Clearing Account accumulates the costs incurred to bill customers for natural gas service and other notifications and includes postage. Forecasted clearing account charges found in Exhibit No. 104 Schedule 1 Page 2 equal $3,900,482 of which $1,131,140 is expensed to the Pennsylvania Division Operation and Maintenance Expense.

Q. Please explain Exhibit No. 104 Schedule 2 (Rate Case) Page 27.

A. As shown in the Exhibit, Distribution has had two base rate cases recently: R-00038168 which was filed April 16, 2003 and effective January 15, 2004 and R-00049656 which was filed September 15, 2004 and effective April 15, 2005. Both of these two cases were settled and did not include full litigation. I have summarized the expense by contractor type for each docket and have brought forward the non-legal expertise costs to 2007 dollars using the inflation factor. Legal costs were brought forward to the same period using the actual increases incurred in between 2003 - 2005. I then averaged the two dockets in 2007 dollars. This calculates a $535,889 average expense for these settled cases. I then added $305,304 of legal services to provide for full litigation. This results in a total cost for the twelve months ending January 31, 2007 of $841,192.

Q. Why did you include expenses for full litigation?

A. Since both of the most recent cases filed with the commission were settled,

the costs incurred with these two proceedings are not representative of rate case expense. In order to provide a correct representation of rate case expense, the expense to fully litigate a case must be included.

Q. Why did you include only legal services for full litigation?

A. The majority of costs associated with the Rate of Return and Depreciation expertise are in the preparation, discovery and rebuttal portions of the case. In both R-00038168 and R-00049656, the company completed through the rebuttal phase of the cases. Therefore these costs are assumed to be representative of full litigation. If full litigation were to include these specific expertise issues, the expense for that expertise would increase but the company cannot predict which areas will be litigated and which will be settled. Full litigation however does involve considerable time for our Legal Services regardless of the issues.

Q. How did you calculate the additional legal services for full litigation?

A. I used the legal expertise expense associated with R-942991, which was the company's last litigated case, and using the actual annual increases brought the costs forward to 2007 dollars. I then took the difference between the total costs for a fully litigated case and the average cost for the settled cases. This resulted in an incremental $305,304 for legal services. The representative rate case expense is for the twelve months ending January 31, 2007 is $841,192.

Q. Please explain the Reconnection Charge shown on Exhibit No. 104

Schedule 2 (Reconnection Charge), Pages 28 - 29.

A. The Reconnection Charge for restoration of service that was terminated due to non-payment is, per the Uniform System of Accounts, a reduction to expense. Reconnections charges are collected to restore service to customers who have been terminated for non-payment. Similar to the calculation for Uncollectible expense, I have used a two year average to determine the number of future test year calls due to reconnections. This was then multiplied by the $69 reconnection fee. Effective November 17, 2005 – March 31, 2006 the company was granted a temporary waiver of the tariff fee of $69 and instead collected $50 per reconnection. This reduction in the fee was taken into account in the appropriate months in the future test year calculation. The total future test year expense for this cost element is forecasted to be ($367,519) or 232,530 more than the normalized historic test year.

Q. Please explain Exhibit No. 104 Schedule 2 (Remittance Clearing) Page 30.

A. The Remittance Clearing Account accumulates costs associated with the remitting of customer payments. The forecasted clearing account is $645,137 of which $187,090 is expensed to the Operation and Maintenance Expense of the Pennsylvania Division.

Q. Please explain Exhibit No. 104 Schedule 2 (Gas Transportation Clearing) Page 31.

A. The Gas Transportation Clearing account accumulates costs incurred to

manage the gas measurement and transportation customer support services provided by Distribution. The forecasted clearing account which incorporates charges outlined in Exhibit No. 104 Schedule 1 Page 2 amounts to $2,640,988 of which $803,856 is expensed to the Pennsylvania Division Operation and Maintenance Expense.

Q. Please explain Exhibit No. 104 Schedule 2 (Kaylor Gas Expense) Pages 32 - 33.

A. Exhibit No. 104 Schedule 2 (Kaylor Gas Expense) Page 33 provides the monthly amortization for costs incurred by Distribution on the Kaylor system as allowed for in R-00049656 Settlement paragraph 45. The settlement specified an 18 month amortization. A balance of $17,229.59 remains in the account as of January 31, 2006. The allowed amortization of 18 months will bring the account to $2,585.29 at October 31, 2006, the end of the 18 months. Assuming a continuation of the current amortization schedule, the monthly amortization of $1,647.30 for November 2006 and a balancing amortization of $937.99 for December 2006 will bring the account to $0 at December 2006. This is summarized on Exhibit No. 104 Schedule 2 (Kaylor Gas Expense) Page 32 CONFIDENTIAL under the first section "Remainder of the deferral allowed in R-0004965". The continuation of the R-00049656 amortization calculates an expense of $17,230 for the twelve months ending January 31, 2007 or $3,885 more than the historic test year amount of $13,345.

As described in Mr. Swartzfager's testimony (Statement No. 14), Distribution is developing products, systems, tools and methods to reduce Distribution's operating costs. The FERC RDD surcharge, referred to as the GTI Delta Fund, is to help provide funding on a national level to achieve utility operating efficiency improvements through the application of new technologies and reduced energy costs to end-users through the improvement of operating efficiencies. Distribution is proposing a GTI Delta Fund expense of $876,942 in the future test year of which $526,466 is currently allowed and is being amortized. The $876,942 represents the amount of funding that would be provided using the demand surcharge of $0.16/Dt times the demand volumes of 4,052,580 and the commodity surcharge of $0.0088/Dt times the commodity sales volumes of 25,969,159. The surcharge values represent the 1999 values provided to GTI before the FERC ordered decreases to these values.

Q. Does Distribution have any GTI funds embedded in its PGC rates?

A. No. Pursuant to FERC requirements, Supply filed tariff sheets which eliminated this charge and Distribution reflected this elimination in the 1307(f) case that was filed on February 1, 2005 effective August 1, 2005.

Q. The R-00049656 Settlement document required an annual report to be served on the parties on or before December 31 for the preceding twelve month period ended September 30. Did you file such report?

A. Yes. Distribution filed with the Commission on December 30, 2005, a Delta

Fund for Research and Development Projects Report. Distribution also held a teleconference with the parties on November 17, 2005 to review for comment a draft of the report. Distribution incorporated the comments received into its annual report.

Q. Would you continue the deferral treatment of the GTI Delta Fund?

A. Yes. All the provisions of the deferral set up in the R-00049656 Settlement would continue with the exception of the amount amortized to expense. This would change to $876,942.

Q. Please discuss Exhibit No. 104 Schedule 2 (Pipeline Integrity) Page 35.

A. Distribution is requesting recovery of the costs of two components to the Pipeline Integrity Expenditures, a Transmission pipeline component and a Distribution pipeline component.

Transmission Pipelines: The Pipeline Safety Act of 2000 called for integrity rules for transmission pipelines in high-consequence areas. Distribution has reviewed these rules and has developed a work plan to meet the specifications of the Act. Lines have to be assessed by December 17, 2007 or December 17, 2012 dependent on the Risk Score. Distribution has determined that 3 transmission lines need to be assessed by December 17, 2007, two of which have costs associated with them. The company estimates that it will expend to Operations and Maintenance Expense approximately $450,000 to meet the December 17, 2007 timeframe. These are outlined in Exhibit No. 104 Schedule 2 (Pipeline Integrity) Page 35. In

addition, Distribution will be capitalizing approximately $125,000 to comply with the Act. These capital expenditures have been included on Exhibit No. 108 Schedule 1 Page 1.

Distribution Pipelines: In December 2005 the "Integrity Management for Gas Distribution, Report of Phase I Investigations" was issued by the Joint Work/study Groups including Representatives of: Stakeholder Public, Gas Distribution Pipeline Industry, State Pipeline Safety Representatives and Pipeline and Hazardous Materials Safety Administration. The report requires each system to:

Develop and implement a written integrity management plan

Know its system infrastructure

Identify existing potential threats

Assess and prioritize risks

Identify and implement appropriate measures to mitigate risks

Measure performance, monitor results and evaluate the effectiveness of integrity management programs, making changes where needed

Periodically report to a limited set of performance measures to its regulators

The company has begun its review of the report: however; a final rule is not expected to be issued until the end of 2006. Distribution believes that the costs of implementing this rule will be similar to the costs of compliance with

performance measures. Distribution is familiar with compliance with performance measures. Performance measures have been implemented in its New York Division, and Distribution has estimated costs to implement similar performance standards in its Pennsylvania Division. Using actual expenses incurred for current performance, an incremental cost was calculated to determine the increase in those expenditures needed to achieve the performance measure. At this time, it is estimated that $1,040,497 of incremental Operations and Maintenance expense will be incurred if similar measures are instituted. This expense is included on Exhibit No. 104 Schedule 2 (Pipeline Integrity) Page 35.

Q. Will the Company be expending any capital dollars to comply with the requirements for the Distribution component?

A. Yes. Distribution has estimated that an incremental $828,611 will be expended to comply with the performance standards for the Distribution component. This has been included on Exhibit No. 108 Schedule 1 Page 1.

Q. Please discuss the request for FERC 2004 expenditures found on Exhibit No. 104 Schedule 2 (FERC 2004) Page 36.

A. This exhibit requests $407,680 for Operations and Maintenance expenditures related with Distribution's compliance with FERC 2004. Exhibit No. 108 Schedule 1 Page 1 requests $313,600 of plant associated with the compliance of FERC 2004.

As stated in Mr. Polka's testimony (Statement No. 12) National Fuel

Gas Supply Corporation ("Supply") has filed with the FERC a Petition for Limited Waivers of Order No. 2004 Standards of Conduct. This petition includes a request to continue sharing the gas dispatch center and its staff. If FERC denies the petition, Distribution estimates that additional costs to Distribution Corporation will be incurred. Specifically, it is estimated that between $600,000 - $1,000,000 will be capitalized to build a new dispatch center. Annual operating expenses are estimated to be $1,300,000. Since this operation will be shared between the New York and Pennsylvania jurisdictions, an allocation based on gas throughput was done. Pennsylvania represented 31.36% of total Distribution throughput for the twelve months ended January 31, 2006. This allocation calculates an increase in Operation and Maintenance expense of $407,680 and an increase to Plant of $313,600 for the Pennsylvania Division.

Q. Has FERC ruled on Supply's petition?

A. To the best of my knowledge, no. Therefore I would propose to defer the costs of implementing FERC 2004, including return, related income taxes, depreciation on plant and expenses. In specific terms, the incremental costs such as computer hardware and software, structure development or enhancement, and outside consultants will be accumulated in a 182 account (deferred regulatory asset). If the Company were to continue to perform off-system sales and capacity releases, instead of passing the ratepayer portion of these sales back to the customer as a credit to gas costs, the revenues

will be applied to the 182 account. These revenues will reduce the costs accumulated in the 182 account. The Company will continue this treatment until the cost of implementing FERC Order 2004 is completely recovered or 5 years, whichever comes first. Any deferred balance remaining in Account 182 as a result of these deferrals after 5 years will be recovered from or flowed through to customers at the conclusion of Distribution's first base rate case thereafter.

Q. When will the costs start to accumulate?

A. Costs will be incurred and accumulated beginning approximately when National Fuel Gas Supply Corporation's ("Supply") compliance filing is complete. That time is not presently known. As implementation costs are incurred, they will immediately be accumulated in the 182 account.

Q. When will the revenues start to accumulate?

A. In response to FERC Order 2004, Distribution has ceased off-system sales effective September 22, 2004. Distribution anticipates that, as a result of FERC Order 2004, it will not be able to make off-system sales at least until Supply's compliance filing has been approved by FERC. Therefore, no net revenues from off-system sales are expected to be accumulated in Account 182 at least until after Supply's compliance filing has been finalized. Distribution, however, has been able to continue to release capacity. Revenues from capacity releases will begin to be accumulated in Account 182 beginning on the day the Commission enters a Final Order approving

deferred accounting for Distribution's costs of implementing FERC Order 2004.

Q. What is required for Distribution to qualify for deferred accounting for its costs of implementing FERC Order 2004?

A. To qualify for deferred accounting, Distribution must meet the requirements of the Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 71 "Accounting for the Effect of Certain Types of Regulation" ("SFAS 71"), which requires that Distribution provide assurance to its outside auditors that it is probable that deferred amounts will be reflected in rates in a period different from the period in which they would have been reflected in the income statement of an unregulated Company. To provide the required assurance, the following language should be included in the Commission's Final Order approving deferred accounting for Distribution's costs incurred as a result of FERC Order 2004:

> National Fuel Gas Distribution Corporation's accounting policies conform to the Statement of Financial Accounting Standards No. 71 "Accounting for the Effect of Certain Type of Regulations" which are in accordance with the accounting requirements and ratemaking practices of regulatory authorities. The application of these accounting policies allows the Company to defer expenses and income on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate-setting process in a period different from the period in which they would have been reflected in the income statement by an unregulated Company.
>
> The costs incurred as a result of FERC Order

2004, including return, related income taxes, depreciation on plant and expenses, are not specifically known at this time, and the impact of the revenues due to off-system sales and capacity releases are also not known. The Company seeks to defer its costs of implementing FERC Order 2004, including return, related income taxes, depreciation on plant and expenses and the customers' portion of net revenues from off-system sales and capacity releases in Account 182 for a five-year period. Any balance remaining in Account 182 from these deferrals is to be recovered from or flowed through to customers commencing at the conclusion of Distribution's first base rates case after conclusion of the five-year period.

The regulatory deferral treatment sought by Distribution for the FERC Order 2004 compliance expenditures is approved, and the relief requested in the case is in accordance with SFAS No. 71.

Q. Please explain Exhibit No. 104 Schedule 2 (Inflation) Page 37.

A. Exhibit No. 104 Schedule 2 (Inflation) Page 37 calculates the inflation factor for the twelve months ending January 31, 2007 based on the March 10, 2006 Blue Chip Indicators. The inflation factor for the twelve months ending January 31, 2007 is 2.6250%.

Q. Please explain Exhibit No. 104 Schedule 3 Page 1.

A. Exhibit No. 104 Schedule 3 Page 1 shows the ratemaking cost elements for the twelve months ended January 31, 2005 and January 31, 2006 and annualized twelve months ending January 31, 2007 (reference Exhibit 104).

Q. Please describe the remaining schedules in Exhibit No. 104 that you are sponsoring.

A. Exhibit No. 104 Schedule 4 addresses the amortization of rate case

expense. Exhibit No. 104 Schedule 5 provides data concerning labor and benefits. Exhibit No. 104 Schedule 6 addresses advertising expense and Exhibit No. 104 Schedule 7 addresses research and development expenditures. Exhibit No. 104 Schedule 8 addresses Distribution's labor productivity.

Q. Please describe Exhibit No 106 Schedule 1 Page 1.

A. Exhibit No. 106 Schedule 1 Page 1 provides a summary of the Taxes Other Than Income Taxes normalized at January 31, 2006 (column (1)) and the rate year at January 31, 2007 in column (3). Taxes Other Than Income Taxes for the twelve months ended January 31, 2006 was $2,091,978. Adjusting the individual components as described below results in a $118,885 decrease or an annual total for the twelve months ending January 31, 2007 of $1,973,094.

Q. Please describe the adjustment to Exhibit No. 106 Schedule 1 Page 2 FICA tax.

A. Exhibit No. 106 Schedule 1 Page 2 outlines the FICA Base and Medicare tax as it corresponds to the adjustment in Pennsylvania labor found in Exhibit No. 104 Schedule 2 (PAD labor). The calculated factor of 7.2278 FICA O&M tax to O&M Labor ($1,014,000 / $14,029,186 = 7.2278%.) was multiplied by the forecasted operation and maintenance labor dollars of $14,678,652 calculated on Exhibit No. 104 Schedule 2 (PAD Labor). This equals $1,060,944 for FICA taxes applicable to the operation and

maintenance portion of labor expense.

Q. Please explain Exhibit No. 106 Schedule 1 Page 3.

A. Exhibit No. 106 Schedule 1 Page 3 outlines Distribution's responsibility for State Unemployment and Federal Unemployment Tax amounts that are charged to operation and maintenance expense.

Calendar 2006 Pennsylvania State Unemployment tax rate was 2.3152% capped at $8,000 per person. Multiplying $8,000 by the number of employees by the applicable rate of 2.3152% calculates a gross amount of $63,529. Applying Factor A achieves an annualized operation and maintenance expense amount of $48,917.

The Calendar 2006 Federal Unemployment rate was 0.8% capped at $7,000 per person. Multiplying $7,000 by the applicable rate of 0.8% by the number of employees calculates a gross amount of $19,208. Applying Factor A achieves an operation and maintenance expense amount of $14,790.

Q. Please describe the adjustment to Exhibit No. 106 Schedule 1 Page 4.

A. Exhibit No. 106 Schedule 1 Page 4 outlines the adjustment the Capital Stock Tax based on 2006 tax rates. The Capital Stock value of $495,045,036 is from the 2004 return. This value is then multiplied by the Pennsylvania Division applicable percentage of 29.2179% to determine the Pennsylvania taxable value. The 2006 capital stock rate of 0.499% was then applied to determine the Pennsylvania Division Capital Stock Tax taxable liability of

$721,762.

Q. Please describe Exhibit No. 108 and the associated schedules.

A. Exhibit No. 108 responds to regulations regarding the rate base. Exhibit No. 108 Schedule 1 provides a summary of rate base by rate base component for the twelve months ending January 31, 2007. Exhibit No. 108 Schedule 2 provides plant in service, Exhibit No. 108 Schedules 3 and 4 outlines the working capital requirement. Schedule 4 is sponsored by Ms.Truitt. Exhibit No. 108 Schedule 5 is sponsored by Mr. Malachowski and provides the Deferred Income Tax calculation. Exhibit No. 109 is sponsored by Mr. Spanos and provides the Accrued Depreciation calculation.

Q. Please describe Exhibit No. 108 Schedule 2.

A. Exhibit No. 108 Schedule 2 Page 1 starts with the adjusted gas plant in service at January 31, 2006 of $418,692,521. The schedule then adds the appropriate months of the Fiscal 2006 and 2007 construction program by plant type with the exception of the month of January 2007 which is reduced by revenue producing construction expenditures. Because revenue increasing plant additions are in service within 30 days, this eliminates any revenue producing CWIP at January 31, 2007. The total change to plant in service (Account 101000) from February 2006 to January 2007 is $12,680,302 for a plant in service balance at January 31, 2007 of $431,372,823. Next I calculate the investment in construction work in progress (Account 107000) that will be completed within the first six (6)

months rates will be in effect (on or before February 28, 2007). The investment in non revenue producing, non expense reducing construction work in progress necessary to maintain safety at existing facilities is based on plant expenditures for the time period February 2007 through June 2007 of $5,330,925 since all of such amounts will be in service by July 2007. This results in a total balance of $436,703,748.

Q. Please describe Exhibit No. 108 Schedule 2 Pages 2 - 5.

A. Exhibit No. 108 Schedule 2 Page 2 summarizes the Fiscal 2006 and 2007 construction expenditures by month by plant type. Exhibit No. 108 Schedule 2 Page 3 provides the retirements by month by plant type. Retirements to General Plant are separated into (1) retirements due to construction activity and (2) annual amortizations of general plant (as per AR-15) not related to construction activity. Exhibit No. 108 Schedule 2 Page 4 provides the Fiscal Year spending percentage by month for the last three fiscal years and the average which is used to allocate expenditures. Fiscal 2005 retirement percentages by month were used to forecast retirements due to expenditures as shown on Exhibit No. 108 Schedule 2 Page 5. Page 6 provides the retirement to additions percentage to determine the retirements for the fiscal years.

Q. Please describe Exhibit No. 108 Schedule 2 Page 7.

A. Exhibit No. 108 Schedule 2 Page 7 determines revenue producing construction expenditures that would be spent in the fiscal year but would

not included as part of Gas Plant in Service at the end of the fiscal year. The analysis for determining revenue producing construction expenditures focuses on Distribution's appropriations within Plant Accounts for fiscal 2005 spending to determine how much of the total expenditures were for revenue producing plant. For fiscal 2005, 0% of Transmission Plant construction expenditures and 20.1977% of Distribution Plant construction expenditures were for revenue producing plant. These percentage were calculated as described below:

Transmission Plant Account 367 Transmission Lines has several different designations embedded within it, appropriations 315A through 315E. Distribution uses appropriation numbers to provide further detail of the FERC Accounts. Appropriation 315A Transmission Lines Extensions is revenue producing, so 100% of the construction expenditures for fiscal 2005 of appropriation 315A ($0 were spent in fiscal 2005) were removed. Appropriation 315A represent 0% of Account 367 at September 30, 2005. Account 369 Measurement and Regulator Stations (delineated as appropriation 325X) is inter-related with Account 367 so 0% of appropriation 325X was removed as revenue producing.

Distribution Plant has several revenue producing appropriations. The first is appropriation 415A Customer Extensions Mains which is located within Account 376 Mainlines. All of appropriation 415A construction expenditures ($730,561.39) is revenue producing. Appropriation 415A

represents 13.59% of Account 376 Mainlines construction expenditures. Account 378 Measurement and Regulator Stations is inter-related with Account 376 so 13.59% of Account 378 (appropriation 425X) or $28,012.42 was removed as revenue producing. Account 380 Services (appropriation 452X new services) is also revenue producing and $1,559,492.65 was removed. Appropriation 455X Automatic Meter Reading Devices (part of Account 381 Measurement and Regulator Equipment) is inter-related with Account 380 Services therefore 25.20% (appropriation 452X percentage) of appropriation 455X expenditures were removed as revenue producing. Account 385 Industrial Measurement and Regulator Stations (appropriation 470X New Stations) was also removed as revenue producing. The total revenue producing fiscal 2005 construction expenditures for Distribution Plant was $2,595,619.56. Total fiscal 2005 construction expenditures for Distribution plant were $12,851,043.69. Revenue producing expenditures represent 20.1977% of total expenditures and was applied to the month of January 2007 Distribution Plant construction expenditures.

Q. Please describe Exhibit No. 108 Schedule 3 Page 1.

A. Exhibit No. 108 Schedule 3 Page 1 is the average balance of the components of the working capital claim (reference Exhibit No. 8 Schedule 3 Page 1) and the forecasted balances for January 2007. The Materials and Supplies, PPUC Assessment, Other Insurance and the AGA Dues balances are forecasted using the increases found in Exhibit No. 104 Schedule 1.

The Gas Storage Inventory balance of $10,083,672 (computed on a 12 month average) has been forecasted based on volumes forecasted for the future test year.

Q. Please describe Exhibit No. 113.

A. Exhibit No. 113 contains responses to miscellaneous regulations and factors that support the Distribution's calculations.

Q. Does this conclude your testimony?

A. Yes, at this time.

Docket No. R-00061493
Statement No. 103

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

Q. Please state your name and address.

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

Q. What is your present position?

A. I am Senior Manager of Tax Services for National Fuel Gas Distribution Corporation ("Distribution").

Q. Have you testified previously in these proceedings?

A. Yes, and my educational and business experience is set forth in my previous testimony, Statement No. 4.

Q. I show you what has been identified as Exhibit No. 107, Schedule 1, page 1 and ask you to explain the exhibit.

A. Exhibit No. 107, Schedule 1, page 1 is a summary of current income taxes and deferred income taxes at present and proposed rates, as adjusted for ratemaking purposes, for the twelve months ending January 31, 2007.

Q. I show you what has been identified as Exhibit No. 107, Schedule 1, page 2 and ask you to explain this exhibit.

A. Exhibit No. 107, Schedule 1, page 2 shows the calculation of federal and state income taxes at existing rates and at proposed rates. The starting point for the calculation of state and federal income taxes is the operating income before income taxes.

Q. Were there other adjustments required to the operating income?

A. Yes. Additional adjustments were made on Exhibit No. 107, Schedule 1,

page 2 in order to derive the income subject to income taxes at present and proposed rates.

The first adjustment is the deduction of interest expense in the amount of $9,413,000. The interest expense deduction is calculated by multiplying the Pennsylvania Division rate base times the debt ratio and embedded cost of debt used in the rate of return calculation.

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

The third adjustment in the amount of $4,838,000 is the additional depreciation allowed for Pennsylvania Income Tax purposes in excess of the annual accrual for rate making. This amount does not include federal bonus depreciation disallowed for Pennsylvania Income Tax.

The Pennsylvania Income Tax statutory rate of 9.99% is applied to income subject to Pennsylvania Corporate Net Income Tax at present and proposed rates to arrive at Pennsylvania Corporate Net Income Tax. The Pennsylvania Corporate Net Income Tax is then deducted to arrive at Income Before Federal Income Tax.

An addition is then made for bonus depreciation of $901,000 to arrive at Income Subject To Federal Income Tax. The federal income tax rate of 35% is applied in computing the federal income tax.

The amounts of current federal income tax and current Pennsylvania Corporate Net Income Tax are shown on Exhibit No. 107,

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

Schedule 1, page 1 on lines 1 and 3.

Q. Refer to Exhibit No. 107, Schedule 1, page 1 and explain the reduction of federal income taxes which results from amortization of the investment tax credit.

A. Federal Income Taxes are reduced by $4,000 per Exhibit No. 107, Schedule 1, page 1. This represents the annual amortization of the Investment Tax Credit applicable to eligible property installed prior to July 1, 1974. Exhibit No.107, page 19, shows the computation of this test year amortization. Option 2 treatment of the Investment credit as provided in Section 46(f)(2) of the Internal Revenue Code requires that deferred credits be amortized ratably over the life of the property as a reduction to the cost of service. This is accomplished on line 4 of Exhibit No. 107, Schedule 1, page 1. Option 2 credits may not be deducted from rate base.

Q. Refer to Exhibit No. 107, Schedule 1, page 1 and explain the deferred income taxes in the amount of $1,539,000 resulting from normalization of tax depreciation.

A. The amount of $1,539,000 is calculated on Exhibit No. 107, pages 5 through 17. Details are provided of accelerated and straight-line depreciation for the twelve months ending January 31, 2007 by vintage of property, from 1970 through 2007.

For 1970-vintage property, normalization is based upon the difference between straight-line tax depreciation, using guideline lives,

and depreciation calculated using the sum of the years digits method and guideline lives. For property of vintages 1971 through 1980, normalization is based upon the difference between straight-line tax depreciation, using guideline lives, and depreciation calculated using the sum of the years digits method and class life Asset Depreciation Range lives. For 1981 through 1986 vintages of property, deferred federal income taxes were computed, as required by Section 168(i) (9) of the Internal Revenue Code, based upon normalization of the difference between straight-line depreciation, computed by applying book rates to the tax basis of the property and tax depreciation using applicable Accelerated Cost Recovery System (ACRS) rates, under Section 168 of the Internal Revenue Code. Pursuant to the Tax Reform Act of 1986 (TRA-86), modified ACRS depreciation is computed on property placed in service on and after January 1, 1987. TRA-86 requires the normalization of these depreciation deductions per Section 203(e) of the act.

Distribution must be permitted to normalize the federal tax effect of the difference between accelerated and straight-line depreciation on property installed in 1970 through 1980, because Distribution's predecessors used straight-line depreciation as their applicable method of depreciation for pre-1970 property and Distribution is, therefore, not authorized by the Internal Revenue Code to deduct accelerated depreciation unless there is normalization. Normalization of the federal

tax effect of the difference between accelerated and straight-line depreciation for property installed in 1981 and thereafter is required by the Economic Recovery Tax Act of 1981, and the Tax Reform Act of 1986 (TRA-86). If Distribution is not permitted to recover the revenues necessary to provide for normalization of such tax effects, Distribution will not be permitted to deduct accelerated depreciation for income tax purposes.

Q. I refer you to Exhibit No. 108, Schedule 5, page 1 and ask you to explain the amount shown for Accumulated Deferred Investment Tax Credit.

A. Exhibit No. 108, Schedule 5, page 1, presents a computation of the Accumulated Deferred Investment Credit Balance as of the end of the future rate year. I have explained in detail in Statement No. 5, the derivation of the adjusted Accumulated Deferred Investment Credit balance at January 31, 2006. On Exhibit No. 108, Schedule 5, page 1 the adjusted balance of accumulated deferred investment tax credits for the Pennsylvania Division at January 31, 2006 is adjusted for amortization of investment tax credits during the future rate year. The balance of $1,869,449 is deducted in determining rate base.

Q. I refer you to Exhibit No. 108, Schedule 5, page 1, and ask you to explain the amount shown for liberalized depreciation.

A. Exhibit No. 108, Schedule 5, page 1 presents the calculation of the Accumulated Deferred Income Tax Balance applicable to the use of liberalized depreciation for tax purposes. The adjusted balance for the

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

Pennsylvania Division at January 31, 2006 is further adjusted to provide for additional deferrals applicable to the use of liberalized depreciation for tax purposes during the future rate year. The balance of $40,939,447 as of the end of the future rate year is deducted in determining rate base.

Q. Does this conclude your testimony?

A. Yes.

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

Q. Please state your name and address.

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

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

A. I am employed by Gannett Fleming, Inc., as Vice President

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. Are you a member of any professional societies?

A. Yes. I am a member of the Society of Depreciation Professionals and the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Have you taken the certification exam for depreciation professionals?

A. Yes, I passed the certification exam of the Society of Depreciation Professionals sponsored by the Society in September 1997 and was recertified in August 2003.

Q. Will you outline your experience in the field of depreciation?

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period June 1986 to December 1995, I took part in the preparation of numerous depreciation and original cost studies for utility companies in various industries. Depreciation studies of telephone companies were performed for United Telephone of

Pennsylvania, United Telephone of New Jersey and Anchorage Telephone Utility. My work in the railroad industry included depreciation studies for Union Pacific Railroad, Burlington Northern Railroad and Wisconsin Central Transportation Corporation.

Assignments in the electric industry included depreciation studies for Chugach Electric Association, The Cincinnati Gas and Electric Company, The Union Light, Heat & Power Company, Northwest Territories Power Corporation and the City of Calgary - Electric System. Pipeline industry assignments included studies for TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

My work for the gas industry included depreciation studies for Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, The Cincinnati Gas and Electric Company, The Union Light, Heat & Power Company, Lawrenceburg Gas Company and Penn Fuel Gas, Inc. Assignments in the water industry included depreciation studies for Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

My participation in each of the above studies included assembly and analysis of historical and simulated data, field reviews, the development of preliminary estimates of service life and net salvage, calculations of annual

depreciation, and the preparation of reports for submission to state Public Utility Commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies, in July 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies, and in December 2000, I was promoted to Vice President of Gannett Fleming Valuation and Rate Consultants, Inc. now the Valuation and Rate Division of Gannett Fleming, Inc. I am responsible for all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory body.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Hampton Water Works Company, Omaha Public Power District, Enbridge Pipe Line Company, Inc., Columbia Gas of Virginia, Inc., Virginia Natural Gas Company, National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions, The City of Bethlehem - Bureau of Water, The City of Coatesville Authority, The City of Lancaster - Bureau of Water, Peoples Energy Corporation, The York Water Company, Public Service Company of Colorado, Enbridge Pipelines, Enbridge Gas Distribution, Inc., Reliant Energy-HLP, Massachusetts-American Water Company, St. Louis County Water Company, Missouri-American Water Company, Chugach Electric Association, Alliant Energy, Oklahoma Gas & Electric Company, Nevada

Power Company, Dominion Virginia Power, NUI-Virginia Gas Companies, Pacific Gas & Electric Company, PSI Energy, NUI - Elizabethtown Gas Company, Cinergy Corporation – CG&E, Cinergy Corporation – ULH&P, Columbia Gas of Kentucky, SCANA, Inc., Idaho Power Company, El Paso Electric Company, Central Hudson Gas & Electric, Centennial Pipeline Company, CenterPoint Energy-Arkansas, CenterPoint Energy – Oklahoma, CenterPoint Energy – Entex, CenterPoint Energy - Louisiana, NSTAR – Boston Edison Company, Westar Energy, Inc., South Jersey Gas Company, Duquesne Light Company, MidAmerican Energy Company, Laclede Gas, Duke Energy Company, Bonneville Power Administration, NSTAR Electric and Gas Company, EPCOR Distribution, Inc. and B. C. Gas Utility, Ltd. My additional duties include determining final life and salvage estimates, conducting field reviews and presenting recommended depreciation rates to management for their consideration.

Q. What is the extent of your formal instruction with respect to utility plant depreciation?

A. I have completed the "Techniques of Life Analysis", "Techniques of Salvage and Depreciation Analysis", "Forecasting Life and Salvage", "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study" programs conducted by Depreciation Programs, Inc. Also, I have completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

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

A. My testimony concerns the depreciation study conducted under my direction and supervision for the Pennsylvania gas plant of National Fuel Gas Distribution Corporation ("National Fuel"). The study was prepared to determine the remaining life annual depreciation accrual and the annual amortization of net salvage to be used for ratemaking purposes.

Q. Have you previously prepared depreciation studies for National Fuel?

A. Yes. I was involved in the depreciation studies for National Fuel's rate proceedings at Docket Nos. R-942991, R-953299, R-00038168 and R-00049656. I have also prepared the last seven annual depreciation reports filed with the Pennsylvania Public Utility Commission.

Q. Have you previously testified on the subject of depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission, the Commonwealth of Kentucky Public Service Commission, the Public Utilities Commission of Ohio, the Nevada Public Utility Commission, the Public Utilities Board of New Jersey, the Missouri Public Service Commission and the Massachusetts Department of Telecommunications and Energy, the Alberta Energy & Utility Board, the Idaho Public Utility Commission, the Louisiana Public Service Commission, the State Corporation Commission of Kansas, the Oklahoma Corporate Commission, The Public Service Commission of South Carolina, Railroad Commission of Texas – Gas Services Division, the New York Public Service Commission, Illinois Commerce Commission, and the Indiana Utility Regulatory Commission.

Q. Please define depreciation as you have used it.

A. My use of the term "depreciation" is in accord with the definition set forth in the Uniform System of Accounts prescribed for Class A and Class B Natural Gas Companies. "Depreciation" refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, requirements of public authorities and the exhaustion of natural resources.

In the study, the straight line remaining life method of depreciation with the average service life and equal life group procedures was used for most of the gas plant. The unit of production method was used for gas production plant. The annual depreciation is based on a system of depreciation accounting which aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of the unit, or group of units, in a systematic and rational manner.

Q. Have you prepared exhibits presenting the results of your study based on gas plant at January 31, 2007?

A. Yes. Exhibit No. 109 Schedule 1, titled "Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant at January 31, 2007", presents the results of my depreciation study.

Q. Please describe the results of your study.

A. The results of the depreciation study as of January 31, 2007, are summarized in Tables 1 through 4 of Exhibit No. 109.

Table 1, Exhibit No. 109 Schedule 1 Pages III-4 through III-6 (also found in Exhibit No. 105) presents a summary of the results of the depreciation calculations by depreciable group related to the original cost of Gas Plant in Service. The table shows the estimated survivor curves, original cost, book reserve, future book accruals, composite remaining life and the calculated annual accrual rate and amount.

Table 2 on Exhibit No. 109 Schedule 1 Page III-7, presents the bringforward to January 31, 2007, of the book reserve as of January 31, 2006. The book reserve at January 31, 2007, by account, was determined by adding estimated accruals, salvage, and amortization of net salvage to and subtracting estimated retirements and cost of removal from the book reserve as of January 31, 2006.

Annual accruals were estimated using the accrual rates calculated as of January 31, 2006. The calculation of the accruals is set forth in Table 3 on Exhibit No. 109 Schedule 1 Page III-8. Salvage and cost of removal estimates were made by applying average salvage and cost of removal percents for the most recent five-year period to estimated retirements. The estimated book reserve by account was allocated to vintages for the purpose of the annual accrual calculation based on calculated accrued depreciation at January 31, 2007.

Table 4 on Exhibit No. 109 Schedule 1 Page III-9 presents a summary of the cost of removal and salvage data for the five-year period 2002-2006.

Q. Are the bases for National Fuel's annual depreciation accrual and depreciation deduction from original cost in this filing the same as the bases used in the previous rate proceeding?

A. Yes. National Fuel's depreciation deduction from original cost in the previous rate proceeding and this filing is the book accumulated provision for depreciation. The annual depreciation accrual used in the previous rate proceeding and this filing is determined on a remaining life basis.

Q. Please summarize the procedure used in performing the depreciation study.

A. The depreciation study consisted of two major parts. The first consisted of a study of service life and resulted in the estimation of service life characteristics for each depreciable group. The second consisted of calculating the annual depreciation.

The service life study consisted of assembling and compiling historical data from the records related to the Pennsylvania Division gas plant of National Fuel; statistically analyzing the data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning Company practices and plans as they relate to plant operations; observing the features of the visible plant in the field; and interpreting the above data to form judgments of service life characteristics.

Iowa type survivor curves were used to describe the estimated survivor characteristics of the mass property groups. Individual service lives were used for major individual units of plant, such as offices and service centers. The life span concept was recognized by coordinating the lives of associated plant installed in subsequent years with the probable retirement date defined by the life estimated for the major unit.

The remaining life depreciation accruals are based on the straight line method of depreciation, the book reserve and composite remaining lives and rates as of January 31, 2007. The composite remaining lives are based on the estimated survivor curves and the attained age of the property and are weighted using the average service life procedure for property installed prior to 1982 and the equal life group procedure for property installed subsequent to 1981.

Q. What statistical data were employed in the historical analyses performed for the purpose of estimating service life characteristics?

A. The data consisted of the entries made to record retirements and other transactions related to the gas plant. These entries were classified by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed. Types of transactions included in the data were plant additions, retirements, transfers and balances. These data were analyzed for the experience band 1960 through 2002.

Q. What was the source of these data?

A. They were assembled from Company property records related to its gas plant in service.

Q. What method was used to analyze the statistical service life data?

A. The retirement rate method was used. It is the most appropriate when aged retirement data are available.

Q. Did you physically observe the Company's plant and equipment in the field?

A. Yes. The field trips are described on Exhibit No. 109 Schedule 1 Pages II-6 and II-7.

Q. Are the factors considered in your estimates of service life presented in Exhibit No. 109?

A. Yes. A discussion of the factors considered in the estimation of service lives is presented on pages II-3 through II-10 of Exhibit No. 109 Schedule 1.

Q. Please use an example to illustrate the manner in which the depreciation study is presented in Exhibit No. 109.

A. I will use Account 376.1, Mains – Excl. Cathodic Protection, for the example, inasmuch as the original cost of distribution mains represents 47 percent of the total depreciable plant and the account serves as a typical illustration. Data were compiled for the statistical analysis for the years 1960 through 2002. The data were subdivided for study into two experience bands, 1960-2002 and 1983-2002. The resulting life tables are presented on pages II-53 through II-58 of Exhibit No. 109 Schedule 1. These two bands, as well as the Iowa 57-L1.5 survivor curve, which was selected to represent the average survivor characteristics are plotted on page II-52. The estimated

survivor curve, 57-L1.5, was based primarily on the original survivor curve for the two experience bands, 1960-2002 and 1983-2002.

The calculation of annual depreciation for the original cost of Mains in service at January 31, 2007, is presented, by vintage, on pages III-142 through III-145 of Exhibit No. 109 Schedule 1. In these calculations, a survivor curve was developed for each vintage, 1883 through 1981, through the use of a computer, using retirement ratios from the Iowa 57-L1.5 survivor curve through January 31, 2007. The expectancy and average life derived from the developed survivor curve for each vintage were used to calculate the accrued depreciation.

The accrued depreciation for vintages 1982 through 2007 is calculated by the equal life group procedure using the Iowa 57-L1.5 survivor curve. In the calculation, the surviving cost in each vintage was further subdivided, through the use of a computer, into depreciable groups according to the expected service lives as defined by the Iowa 57-L1.5 survivor curve. The accrued depreciation is derived for each equal life group, based on its service life, and the totals shown for the vintages are the summations of the individually derived amounts.

The book reserve was allocated to vintages based on the calculated accrued depreciation. The remaining lives and rates of the vintages were based on the Iowa 57-L1.5 survivor curve, the attained age, and the same group procedures as were used to calculate accrued depreciation. The future book accruals (original cost less allocated book reserve) are divided

by the remaining lives to derive the annual depreciation accruals by vintage. The totals at January 31, 2007, on Exhibit No. 109 Schedule 1 page III-145 are brought forward to Table 1 on page III-5 of Exhibit No. 109 Schedule 1.

Q. Is the procedure you described for Account 376.1 typical of that followed for most of the original cost?

A. Yes it is.

Q. Did you prepare the basis for the amortization of negative net salvage?

A. Yes. The salvage data are summarized on page III-9 of Exhibit No. 109 Schedule 1. Page III-9 presents the cost of removal and salvage related to regular retirements for the fiscal years 2002 through January 2006 and the estimated cost of removal and salvage related to projected retirements for the eight months ended September 2006, the resulting negative net salvage (cost of removal in excess of salvage) and the annual amount based on a five-year amortization period. Costs and receipts associated with the sale of operating plant were excluded from the presentation to the extent that they represent the recovery of original cost. Detailed data related to the experienced and estimated cost of removal and salvage are presented on pages III-176 through III-179 of Exhibit No. 109 Schedule 1.

Q. Does this conclude your direct testimony?

A. Yes, it does.

National Fuel Gas Distribution Corporation
Direct Testimony of Regina Truitt

Q. Please state your name and business address.

A. My name is Regina Truitt. My business address is 6363 Main Street, Williamsville, NY 14221.

Q. Did you submit previous direct testimony in this proceeding?

A. Yes, I submitted Statement No. 5 which related to the per book revenues and the adjustments to the per book revenues for the historic test year (twelve months ended January 31, 2006) for National Fuel Gas Distribution Corporation ("Distribution"). Statement No. 5 also supports the calculation of the lead/lag days used in the calculation of the cash working capital for the historic test year and the future test year.

Q. What is the subject matter of this statement?

A. This statement relates to the calculation of the revenues for the twelve months ending January 31, 2007. These calculations are presented in Exhibit No. 103. I will also address the cash working capital (Exhibit No. 108, Schedule 4) and the Cost of Service Studies presented in Exhibit No. 111.

Q. Please describe Exhibit No. 103.

National Fuel Gas Distribution Corporation
Direct Testimony of Regina Truitt

A. Page 1 of Exhibit No. 103 is the summary page of the revenues for the twelve months ending January 31, 2007. Column 1 presents the revenues projected for the twelve months ending January 31, 2007.

The second column presents the ratemaking adjustment to those revenues. No ratemaking adjustments are presented in this filing.

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

I have presented two columns four (4NS & 4S) and five (5NS & 5S) in order to provide more information in this filing. The fourth column represents the adjustment to price the future test year volumes at the proposed rates and the fifth column is the future test year volumes priced at the proposed rates. The columns four (4NS) and five (5NS) present the proposed rates using the non-seasonal rate design. This presentation is only for informational purposes. Columns four (4S) and five (5S) represent the proposed seasonal rate design.

Pages 2 through 7 contain the responses to filing requirements in the Commission's regulations pertaining to revenues in the future test year.

Q. Please describe Schedule 1 of Exhibit No. 103.

National Fuel Gas Distribution Corporation
Direct Testimony of Regina Truitt

A. Schedule 1 is the calculation of revenue during the future test year at current and proposed rates. The first three columns reflect the volumes projected during the future test year by Ms. Zablonski. The volumes are then priced at the rates that went into effect on April 15, 2005 in Supplement 52, which reflected the base rate change ordered by the Commission in Case R-00049656. The rates also reflect the gas cost rates that became effective on February 1, 2006 (Supplement 58 to Tariff PA P.U.C. No. 9). The exception is that certain surcharges were not included in the calculation of the revenues.

Q. You have reflected $.5806 per Mcf for the LIRA surcharge (Rider F) in the proposed rates. Is this the current rate?

A. No, it is not. The LIRA surcharge had to be adjusted due to the migration of customers from residential to the LIRA rates. The LIRA surcharge is premised on the idea that the residential customers will support the discount included in the LIRA rates. This makes the offering of the LIRA rates revenue neutral (based on normal weather) to the company. The LIRA surcharge is calculated quarterly based upon the forecast of discounts to be offered in the upcoming 12 months. In order

to reflect the revenue neutrality of the LIRA program, the LIRA surcharge was calculated to reflect the neutrality.

Schedule 1 then calculates the revenues at the proposed rates in the remaining columns. The seasonal rate design proposed necessitates that the revenues are calculated using a winter rate and a non-winter rate. The volumes were divided between the two periods based upon the monthly forecast and multiplied by the applicable rates. The two periods were then added together to calculate the Normalized Revenues at Proposed Rates. The final two columns shows the dollar and percentage increase for each rate schedule.

Q. Please describe Exhibit No. 103, Schedule 2.

A. Exhibit No. 103, Schedule 2 has been presented for informational purposes only. It provides the proposed revenues at the current non-seasonal rate design.

Q. Please describe Exhibit No. 103, Schedule 3.

A. Exhibit No. 103, Schedule 3 calculates the late payment revenues using the historic year factor, which is applied to the normalized volumes priced at current rates and at proposed rates, presented using the non-

seasonal rate design (for informational purposes only) and the seasonal rate design.

Q. What does Exhibit No. 103, Schedule 4 represent?

A. Schedule 4 shows the number of customers during the future test year and how many customers will experience a base rate increase under the proposed rates.

Q. Exhibit No. 108, Schedule 4 presents the calculation of the Cash Working Capital ("CWC") for the future test year. Are you responsible for this exhibit?

A. Yes, I am. Exhibit No. 108, Schedule 4 uses the values presented on Exhibit No. 102 and Exhibit No. 104 and the lead and lag days are the same that are described in my Statement No. 5.

Q. Are you also responsible for the cost of service studies presented in this filing?

A. Yes, I am.

Q. Would you state the purpose of a fully allocated cost of service study?

A. A fully allocated, cost of service study assigns to each revenue or customer class its proportionate share of the company's total cost of service. Fully allocated, cost of service study results can be utilized to

determine the relative cost of service for each class of customers and to help determine the individual class revenue requirements. Fully allocated, cost of service studies can also be used to determine the appropriate rate structures of individual customer classes.

Q. Describe the general procedure employed in performing fully allocated cost of service studies.

A. The general procedure employed in performing fully allocated, cost of service studies consists of four separate steps or phases. The four separate steps are: (1) functionalization of plant and operating expenses; (2) classification of costs; (3) derivation of allocation methods; and (4) the actual allocations of plant and expense items to the customer classes.

The first step, functionalization of plant and operating expenses, identifies and separates plant and cost elements into specific categories based on the various characteristics of utility operation. For Distribution, the functional cost categories for plant include natural gas production, transmission, distribution, general, and intangible plant. Operating expenses are functionalized as natural gas production, gas supply, transmission, distribution, customer accounts, customer service, and

administrative and general. The Federal Energy Regulatory Commission Uniform System of Accounts defines the standards for the functionalization of plant and operating expenses.

Step (2) of the general procedure used in performing fully allocated cost of service studies is the classification of costs. The classification of costs further separates the functionalized plant and operating expenses into four basic components. The four basic components of cost classification are: (1) demand or capacity-related, (2) commodity or energy-related, (3) customer-related, and (4) revenue-related.

Demand or capacity costs are related to plant and expenses incurred due to a customer's peak load requirement. The number of customers or the amount of annual usage does not directly impact the level of demand costs. Commodity or energy costs are incurred in proportion to the customer's volumetric gas consumption. Neither demand-related plant and expenses nor customer related plant and expenses impact upon the level of commodity costs. Costs associated with providing service to a customer are defined as customer related costs. Costs associated with the customer's total annual use of gas or

the customer's total peak demand for gas are not included in customer related costs. Revenue related costs are costs, which vary by the amount of revenue received by the utility. Each of the previously functionalized costs are further identified as related to one or more of these cost classes.

The third step of the general procedures used in performing fully allocated, cost of service studies is the derivation of allocation methods. The essential element in deriving reasonable cost of service allocation methods is the establishment of operating relationships between customer gas service requirements and the cost incurred by Distribution in meeting these requirements. These relationships are established by analyzing the gas system design and operations, Distribution's accounting records, and load data and sales revenues by revenue classifications. From the results of the analyses, methods of direct assignment and common plant allocation are chosen for all plant and expense elements.

Direct assignments of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are

developed by detailed analyses of maps and records, work order descriptions, property records and/or customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint-use plant.

Common or joint-use plant allocation methodologies are chosen by analyzing the distinguishing operating characteristics of each customer class. These operating characteristics include annual gas consumption, peak period usage, load factor, and the numbers of customers in a particular class.

The actual allocation of plant items and expense items to the customer classes is the fourth, and final, step in the procedure. Actual allocation entails the application of previously chosen common allocation methodologies to the functionalized and classified plant and expenses that have not already been directly assigned.

Q. What cost of service study allocation methodologies were utilized in developing class revenue levels to move toward equal rates of return?

A. Mr. Clark utilized a hybrid of the results from cost of service studies employing four different cost allocation methodologies. The four different methodologies used were: (1) Peak and Average allocation methodology with no customer component of distribution mains; (2) Peak and Average allocation methodology with distribution mains classified as demand and customer related; (3) Peak allocation methodology with no customer component of distribution mains; and (4) Peak allocation methodology with distribution mains classified as demand and customer related.

Q. Refer to Exhibit No. 111. Was this exhibit prepared by you or under your supervision?

A. Yes.

Q. Describe Exhibit No. 111.

A. Page 1 of Exhibit No. 111 provides responses to the filing requirements of the Commission's regulations pertaining to the cost of service studies in the future year. Cost studies were performed under both present and proposed rates utilizing the (1) Peak and Average allocation methodology with no customer component of distribution mains (100% demand related); (2) Peak and Average allocation methodology with distribution mains classified as demand and customer related; (3) Peak

allocation methodology with no customer component of distribution mains (100% demand related); and (4) Peak allocation methodology with distribution mains classified as demand and customer related.

Q. Please describe Exhibit No. 111, Schedule 4, Page 1.

A. Schedule 4, Page 1 of Exhibit No. 111 summarizes the results of the cost studies, which are included as Exhibits 111-A through Exhibit No. 111-H. This summary includes the type of cost study performed and the actual and relative (unitized) rates of return on net rate base for each customer classification analyzed.

Q. Describe Page 2 of Schedule 4 of Exhibit No. 111.

A. This exhibit presents a customer cost analysis that compiles customer related costs incurred by Distribution associated with having customers connected to the gas system without regard to the level of their gas consumption. The peak and average allocated cost of service study, with no customer component of distribution mains (100% demand related), as found in Exhibit No. 111-A provides the data required for the analysis. Page 2 of Schedule 4, Exhibit No. 111 summarizes the total annual customer related costs and develops a monthly customer related cost per customer.

National Fuel Gas Distribution Corporation
Direct Testimony of Regina Truitt

Q. Describe Exhibit No. 111, Schedule 4, Page 3.

A. This Schedule provides a demand cost analysis and compares the results of the analysis to Distribution's current LBS rates. Exhibit No. 111, Schedule 4, Page 3 provides a cost analysis of demand related costs based on the peak and average cost of service studies with distribution mains allocated as 100% demand related for the future test year (Exhibit No. 111-A). On November 28, 1988 Distribution filed Supplement No. 23 to National Fuel Gas Distribution Tariff Gas - Pa. P.U.C. No. 7. Supplement No. 23 proposed the establishment of Load Balancing Technology Service (LBTS) rates. The LBTS rates are designed to utilize a demand commodity rate structure. On April 6, 1989 the Commission approved, with modifications, the Company's LBS rates. Customers who qualify for Commercial and Public Authority, IVIS, LVIS, and LIS rates may be eligible to receive service under the Company's LBS rates. The demand cost analysis presented on Page 3 of Schedule 4 provides demand costs based on the peak and average cost of service studies with distribution mains classified as demand for all customer classes, which may have customers that could possibly qualify for the LBS rates.

National Fuel Gas Distribution Corporation
Direct Testimony of Regina Truitt

Q. Describe Exhibit No. 111, Schedule 4, Page 4 of 4.

A. The Company has proposed to facilitate the move to an unbundled rate design with the creation of a Merchant Function Charge ("MFC"). (See testimony of Mr. Meinl.) The analysis on Schedule 4, Page 4 of 4 details the allocation of the Uncollectibles and the Storage Inventory to Residential and Non-Residential Classes. The Uncollectibles were first allocated between Non gas cost and gas cost. The Gas Cost portion of the uncollectibles is the only portion included in the Merchant Function Charge. This was determined by examining Exhibit No. 103, which details the calculation of the revenues. The Gas Cost Revenues make up 75.54% of the total revenues in the future test year.

For the Storage inventory I used the allocation between Residential and the Non-Residential Classes found on Line 164 of Exhibit No. 111-A, Schedule 1.

I then determined the revenue requirement associated with the uncollectibles and the Storage Inventory, added them together to determine the Total to be Recovered by the MFC. This was divided by the Retail Volumes to calculate the MFC per Mcf. The MFC Percentage

is calculated by dividing the Total to be recovered by the Gas Cost Revenue (8,241,473 / 320,397,574).

Q. Describe Exhibit Nos. 111-A through 111-H.

A. Exhibit Nos. 111-A through 111-H present the different cost of service studies performed by the Company. Each exhibit is set up in the same manner. Schedule 1 of the exhibit is the cost of service study. Schedule 2 provides references for the allocation methods used to allocate each plant and expense item. Schedule 3 provides details for the allocation methods utilized in the cost studies. The following table shows the differences between each of the study. For example, Exhibit 111-A presents the cost of service study performed for the future test year based on present rates utilizing the peak and average method of allocation of demand related cost of service and allocating distribution mains as 100% demand related.

Method/Mains Allocation	Current Rates	Proposed Rates
Peak & Average No Customer Component	Exhibit 111-A	Exhibit 111-B
Peak & Average Customer Component	Exhibit 111-C	Exhibit 111-D
Peak No Customer Component	Exhibit 111-E	Exhibit 111-F
Peak Customer Component	Exhibit 111-G	Exhibit 111-H

These exhibits present the allocations of plant and expenses and present the resulting net rate base and net operating income by customer class for each of the cost studies presented.

Q. Please give an example of how to trace the allocation methods used in the cost allocation study using Exhibit 111-A.

A. Referring to page 1 of 11 of Schedule 1 of Exhibit No. 111-A, $34,697,699 is listed for transmission plant on line 16 under the TOTAL COMPANY column in the "Gas Plant in Service" section. Next, proceed to page 1 of 11 of Schedule 2 of Exhibit No. 111-A (allocation assignment report). From Line 13 of Schedule 2 of Exhibit No. 111-A, page 1 of 11, it can be seen that this page provides allocation assignments for the "Gas Plant in Service" report of the cost allocation study presented in Schedule 1 of Exhibit No. 111-A. Line 16 of the allocation assignment report provides allocation information concerning the transmission plant presented in the Gas Plant in Service section of the cost of service study report. From Column R, Line 16 of the allocation assignment report it can be seen that the $34,697,699 of transmission plant has been allocated using allocation factor number 50. Column S, Line 16 of the allocation report also indicates that

transmission plant is allocated on the peak and average basis without LIS. The transmission plant allocated to each of the classes is shown on line 16, page 1, columns V through AC, of Schedule 1 of Exhibit No. 111-A and totals the $34,697,699. The allocation methods for other plant items, revenues, operation and maintenance expenses, taxes other than income taxes, etc., may be found in a similar manner by referring to the column letters and row line numbers of the pages in Exhibits Nos. 111-A, which show the items allocated, and then referring to the corresponding allocation assignment reports in Schedule 2.

Q. Describe Schedule 3 of Exhibit Nos. 111-A through 111-H.

A. Schedule 3 of each exhibit lists the actual allocation factors and allocation percentages used to derive the cost allocations in each of the cost studies. The actual allocation percentages used to derive the allocated plant and expenses shown in Schedule 1 can be located in corresponding Schedule 3 of the exhibit by simply referring to the allocation factor number identified in Schedule 2. Continuing our previous example, the allocation percentages for Allocation Factor #50, used to allocate transmission plant on page 1 of Schedule 1 of Exhibit

No. 111-A, are provided on page 2 of Schedule 3 of Exhibit No. 111-A under allocation Factor #50 (Peak And Average w/o LIS).

Q. Would you please summarize the cost study exhibit relationships just discussed?

A. As an example, for the cost allocation study under present rates utilizing the peak and average allocation methodology, and classifying distribution mains as 100% demand related, the following exhibits include all cost study results, details, and supporting information:

Schedule 1 of Exhibit No. 111-A: Allocation Cost of Service Study

Schedule 2 of Exhibit No. 111-A: Allocation Report

Schedule 3 of Exhibit No. 111-A: Allocation Factors

Q. What was the source of the cost data analyzed in the class cost of service studies?

A. All cost of service data have been taken from the supporting data filed by Distribution in the exhibits of this case for the future test year. Where more detailed information was required to perform various special studies, the data were derived from the historical books and records of Distribution.

National Fuel Gas Distribution Corporation
Direct Testimony of Regina Truitt

Q. Which common allocation methodology was chosen to allocate demand related plant and expenses?

A. The peak and average allocation methodology with no customer component of distribution mains (100% demand related) was utilized in Exhibit Nos. 111-A and 111-B. The peak and average allocation methodology with distribution mains classified as demand and customer related was utilized in Exhibit Nos. 111-C and 111-D. The peak allocation methodology with no customer component of distribution mains (100% demand related) was utilized in Exhibit Nos. 111-E and 111-F. The peak allocation methodology with distribution mains classified as demand and customer related was utilized in Exhibit Nos. 111-G and 111-H. The peak and average cost of service studies are presented in compliance with the Commission directive given in the Commission's order in a previously filed Company base rate case, Case R-870719:

> "We do not endorse any of the cost of service study methods proposed by the various parties. We do, however, accept the OCA's study as the most useful guide to test the reasonableness of the various revenue allocation proposals. Therefore, we will require the Company to file a peak and average class cost of service study in its next base rate proceeding. " (Order entered May 27, 1988 at Docket No. R-870719, pg. 138)

National Fuel Gas Distribution Corporation
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Q. Describe the special studies that were performed and how they relate to the allocation methods presented in Exhibit Nos. 111-A through 111-H.

A. Special studies were conducted for the major distribution plant accounts of Distribution. These analyses were performed so that the particular plant accounts analyzed could be directly assigned to the customer classes.

For Account 376 - Distribution Mains, different methodologies were utilized under the various cost of service studies presented. For each study, distribution mains were directly assigned to the LIS class. For each LIS customer, the entire length of mainline pipe (by size) from the customer's facility to a National Fuel Gas Supply line or interstate pipeline was identified and then priced out at the average cost per foot for each size pipe. In order to be conservative, the LIS customer was assigned the full responsibility for the length of mainline identified as needed to serve the LIS customer, even if as is usually the case, other customers are served from that mainline. The fact is that a single main from a source of supply to an LIS customer together with a meter, service and regulator, are all that are required to serve LIS customers. This point has been demonstrated time and time again by the successful

use of bypass facilities, which generally consist of only these simple facilities. The direct assignment of distribution mains to the LIS class was approved by the PUC at R-942991.

Distribution's transmission mains were also not allocated to the LIS class since the entire length of main line used to serve LIS customers was priced out at the appropriate distribution main cost.

The allocation of the remaining mains in each study was shown in the table previously in my testimony.

For Account 380 - Services, an analysis was performed to directly assign the plant investment in this account to each of Distribution's customer classes. The first step involved determining the number of services and total costs, by service line type, from Distribution's Plant Accounting System. These data were then entered to develop an average cost by size of service as well as the total historical Account 380 balance. The second step utilized information linking individual service lines to a customer class wherein the number of service lines by size and customer class was developed. This data was then priced out at the average cost of the respective service line size to determine the preliminary costs assigned to each customer class. At this point,

approximately 98% of the total number of services had been directly assigned to the appropriate customer classes. Some of the services could not be directly assigned since there were a number of older service line records which do not have the information necessary to identify the customer's service class. The third step was to calculate the number of unassigned service lines and allocate them to the available customer classes. During this step, the number of unassigned services, by size, was allocated to each customer class based on the already assigned number of services, by size. The last step was to calculate the total Account 380 investment by customer class, which then provides the historical basis on which to allocate the Account 380 plant for the future rate year. This service allocation methodology was utilized for all the cost of service studies presented.

A detailed analysis was performed to determine the direct assignment of investment in Meters, Account 381. With the assistance of a computer program developed for meter analysis purposes, meter data providing the number of meters installed for each meter code by customer classification was extracted from the customer history records. The meter codes were then related to the various categories of meters

booked in Distribution's Continuing Property Records. The unit investment in each meter category was computed and then multiplied by the number of meters in each customer classification to derive the total investment in meters by customer classification.

Q. Does Distribution lease some of the meters, which are installed on the customer's premises?

A. Yes. However, the costs of leased meters are not included in Account 381. As a result, when the total meters installed on customers' premises were compared to the booked number of meters, the resulting amount of total meters installed was greater. A downward adjustment to the number of meters by customer classification was necessary to eliminate the leased meter costs from the computed meter investment.

Q. How was the leased meter adjustment made?

A. An analysis of meters leased was performed. This analysis consisted of the number of leased meters by meter category. After relating the meter categories to the meter codes from the previous computer analysis, leased meters were assigned to each customer classification in proportion to the previously derived number of meters by class. Subtracting the number of leased meters resulted in a meter investment

balance by customer class, which constituted the company owned meter investment corresponding to the Account 381 balance. The resulting direct assignment of this meter investment to the customer classes can be located on page 1, line 32 in the cost studies.

Q. Describe the special study performed for Industrial Measuring and Regulating Station Equipment - Account 385.

A. Distribution maintains property ledgers for Account 385 detailing the investment of each commercial, public authority, and industrial station and the customer for whom that station was installed. From these data, it is possible to directly assign this account's investment to the appropriate non-residential customer classifications. In cases where customer names have been changed since the original installation or a particular installed station did not have a specific customer designation, the investment was allocated to the non-residential classes in proportion to the direct assignments just mentioned. Page 1, line 26 in each of the cost studies provides the investment amounts associated with each customer class.

Q. How much of the total gross distribution plant did you allocate or directly assign to the customer classification based upon these special studies or Commission directive?

A. Approximately 94% of the total gross distribution plant was directly assigned or was allocated based on the special studies of Accounts 376, 380, 381, and 385. Since many operation and maintenance expense accounts are allocated based on their associated plant accounts, it was important to allocate as much plant using special studies as possible. Each component of the remaining 6% of total gross distribution plant was allocated among customer classes on the basis of demand or customer allocation factors. Judgment was exercised in determining which allocation factor should be applied to each component of the remaining 6% of gross distribution plant.

Q. Describe the method used to allocate the reserve for depreciation, and depreciation expenses.

A. These items were allocated by function in proportion to their associated plant accounts. The results of these allocations can be found in Exhibit Nos. 111-A through 111-H by referring to the "Accumulated Reserve for

Depreciation" and "Depreciation Expenses" reports on pages 2, and 3 respectively in each of the cost studies.

Q. How was the working capital component of rate base allocated?

A. Cash working capital was allocated in proportion to the sum of operation and maintenance expenses and taxes other than income taxes by class. This approach was consistent with the methodology used to derive the cash working capital requirement on a total company basis. The "Working Capital" report on page 4 in the cost studies provides the allocated class amounts. For the materials and supplies component of working capital, the Materials Management Department of Distribution provided an analysis of the average dollar value of materials and supplies inventory, broken down into the most common inventory items. Each of these items was allocated in proportion to its related plant account, and can also be found on page 4.

Q. Explain how Operation & Maintenance Expenses were allocated.

A. These expenses, excluding purchased gas expenses, were generally allocated on the basis of their associated plant accounts.

Q. Were purchased gas expenses included in the cost studies?

A. Yes they were included in the cost studies and assigned to the commodity function and allocated to each class using the actual costs as developed in Exhibit 103.

Q. Describe the method used to allocate Customer Service Expenses.

A. Through discussions with various Energy Services and Corporate Communication Department personnel of Distribution, Customer Service Expenses were broken down into specific departmental activities. Account 910 - Customer Assistance Expenses was analyzed by activity to ascertain the customer groups that were directly affected by this account's activities. Each activity was assigned to residential only, commercial/public authority, industrial, or all customer groups. Customer Assistance Expenses assigned to commercial/public authority, industrial, or to all customer groups were then allocated to the rate classes within these groups based on number of customers. Informational Advertising Expenses - Account 911 was allocated in a similar manner. Page 6, line 293, in Schedule 1 provides the allocation of total customer service costs to each customer class. Customer service expenses incurred exclusively to administer transportation service, are separately identified on line 294 of page 6 of Schedule 1. Transportation administration

expenses are allocated to the customers classes based on the number of transportation customers within each class.

Q. Describe the method used to allocate certain administrative and general expenses that were considered to be labor related.

A. To reflect, in the cost allocation process, the labor related nature of certain administrative and general expense items such as salaries, pensions and benefits, it was necessary to perform an analysis of direct labor expenses included in the previously allocated operation and maintenance expenses. This analysis can be located on page 5, in Schedule 1. The direct labor expense in each of the accounts on page 5 was allocated to the classes on the same basis as the corresponding expense accounts located in the operation and maintenance expense reports on pages 6, 7, 8, and 9. The resulting amounts allocated to each of the customer classes, when summed together by class, determined the direct labor expense allocation factors that were used for these and subsequent labor related cost allocations. It should be noted that the labor expenses as shown include the benefits from Account 926, which contains all of the Operations and Maintenance benefits such as

pension, OPEBs and Hospitalization. This reclassification was done in order to more accurately reflect the labor allocation.

Q. How were Taxes Other than Income Taxes allocated?

A. These taxes were allocated based on two tax groupings: (1) labor related and (2) plant related. Federal and state unemployment compensation and FICA, which are labor related, were allocated in proportion to the class allocated direct labor expenses using the direct labor expense allocation factors discussed above. Property, city license and capital stock taxes, being plant related, were allocated on a total plant basis. The resulting class allocated costs can be found in the "Taxes Other than Income Taxes" report on pages 9 and 10 in Schedule 1.

Q. How were Income Taxes determined for each customer classification?

A. Income Taxes were computed for each customer class by using class revenues, previously allocated expenses and certain income tax computation components, which were not already allocated. This approach made certain that the income tax computation for each customer class reflected the proper weighing of revenues and expenses. The "Income Taxes" report on page 10 in Schedule 1 provides the allocation results.

National Fuel Gas Distribution Corporation
Direct Testimony of Regina Truitt

Q. Discuss the results of the cost of service studies just described.

A. Page 1 of Schedule 4, Exhibit No. 111 summarizes the results at present and proposed rates for each of the cost of service studies conducted by Distribution.

Q. What changes to the Justified Investment Factor has Distribution proposed?

A: Distribution proposes to adjust the investment factors due to the proposed changes in rate of return, working capital, gross plant, depreciation, proposed rates, interest rates, federal and state income taxes, and retention factors.

Q. Does this complete your testimony?

A. Yes, it does.

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

Q. Please state your name and business address.

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

Q. Did you previously submit direct testimony in this proceeding?

A. Yes. I submitted Statement No. 6.

Q. Please refer to Exhibit No. 110, Schedules 1 through 7 and explain them.

A. These exhibits provide the same information as provided in Exhibit No. 10, Schedules 1 through 7, respectively, which have been previously explained.

Q. Please refer to Exhibit No. 110, Schedule 8 and explain it.

A. Exhibit No. 110, Schedule 8 provides the annualization of sales volumes, for the twelve months ending January 2007, for changes in the projected number of customers. The methodology employed and the volumetric adjustment by class are explained on Exhibit No. 110, Schedule 8.

Q. Please explain Exhibit No. 110, Schedule 9.

A. Exhibit No. 110, Schedule 9, Pages 1 and 2 summarize by month and in total of the projected sales and transportation volumes for the future test year, the twelve months ending January 2007. Pages 3 and 4 of Exhibit No. 110, Schedule 9 summarize by month and in total of the projected number of customers for the future test year, the twelve months ending January 2007. The commercial and public authority classes are segregated into customers consuming less than 250 Mcf per year (Lower Limit (LL)), customers consuming between 250 and 1,000 Mcf per year (Upper Limit

(UL)) and customers consuming greater than 1,000 Mcf per year (Large). The annual load growth adjustment defined on Exhibit No. 110, Schedule 8 is also included as an addition to the total projected sales volumes.

Q. What level of annual degree days was used to develop the projected sales volumes?

A. The level of degree days used to develop the projected sales volumes in this proceeding is 6,243. Normal degree day values are based on the period 1971 through 2000 as calculated and published by the National Oceanic and Atmospheric Administration (NOAA), for the first-order National Weather Service Office located at the Erie, Pennsylvania International Airport.

Q. Please explain Exhibit No. 110, Schedule 10.

A. Exhibit No. 110, Schedule 10 is a detailed description of the Company's sales and transportation forecast for the twelve months ending January 2007. Pages 1 and 2 describe the exhibit, pages 3 through 6 summarize the methodology employed.

Q. Please describe generally the sales forecast.

A. The forecast for the Company's Pennsylvania Division segments its markets into large and small volume sectors using an industrial throughput break point of 50,000 Mcf per year. The genesis of this segregation was the initial offering of transportation service to industrial customers consuming in excess of 50,000 Mcf per year. Although the volumetric

requirements for transportation service have been altered over the years, the 50,000 Mcf break point remains a legitimate segmentation point between large and small volume industrial customers.

The small volume sector consists of all residential, commercial, public authority and small industrial categories. Separate forecasts are made for use-per-account and the number of accounts using econometric models, when applicable, which describe average annual usage and number of accounts, for each class, as a function of one or more economic explanatory variables.

Q. Please explain why separate forecasts are specified for use-per-account and the number of accounts.

A. Each of these components of total consumption is influenced by different factors, which must be analyzed separately. Segregating total consumption into these components builds more structure into the analysis of the determinants of gas consumption. Total consumption for a customer class is the product of average use-per-account for that class and the number-of-accounts.

Q. Please continue.

A. The greater structure afforded by separate analyses of use-per-account and number-of-accounts is desirable for both model specification and forecast validation purposes. This is true for the residential, commercial and public authority customer categories.

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

With respect to model specification, from economic theory we expect customer usage of a product to be influenced by the price of the product and, in the case of natural gas, weather and conservation efforts.

Q. Why have you chosen econometric modeling to forecast use-per-account?

A. The word "Econo-metric" means measuring economic relationships. The technique of econometric modeling incorporates hypotheses from economic theory and statistical tests of those hypotheses. The economic theory of consumer behavior, for example, postulates that household income, the price of natural gas, weather and consumer preference are major determinants of household natural gas usage. Econometric techniques, such as regression analysis, allow for testing of these hypotheses and measurement of the relative impact of each postulated determinant on natural gas usage.

Q. What criteria did you use to select the final forecast equations for the residential, commercial and public authority categories?

A. The forecast equations were developed using regression analysis. The following criteria were used to evaluate each estimated equation: (1) the signs and magnitudes of the estimated coefficients of each potential explanatory variable; (2) the adjusted coefficient of determination, or R-squared, which is an indication of the explanatory power of the equation; (3) the t-ratios which test the significance of a particular coefficient; (4) the Durbin-Watson statistic, which tests for serial correlation in the residuals;

and (5) the standard error of the regression, which is an additional measure of the explanatory power of the equation.

Q. What was the first consideration used to evaluate each estimated equation?

A. The fundamental criterion used to evaluate potential forecast equations was to reject any equation, which included variables with coefficients whose signs were contrary to economic theory. For example, from economic theory, we would expect heating degree days to have a positive impact on natural gas usage. This variable then should have a positive coefficient estimate. We would also expect, based upon economic theory, that increases to the price of natural gas would have a negative impact on natural gas usage. This variable should have a negative coefficient estimate.

Q. Please describe the other statistics used to evaluate each estimated equation.

A. The adjusted coefficient of determination, R-squared, indicates the percentage of past movement in natural gas usage which is explained by the estimated equation. The highest coefficient of determination indicates the equation, which explains the largest percentage of the past movement in gas usage.

Other statistics used to evaluate the estimated forecast equations were the t-ratios and the Durbin-Watson statistic.

The t-ratio was calculated for each explanatory variable in the

estimated equations. The t-ratio is calculated as a variable's estimated coefficient divided by the associated standard error. As a general rule, the coefficient is statistically significant if the absolute value of the t-ratio is 2.0 or greater.

The Durbin-Watson (D-W) statistic tests for the presence of a pattern (i.e., serial correlation) in the residuals. A residual is the difference between the actual value of an observation and the corresponding fitted value from the regression equation. A fundamental assumption of regression analysis is that the residual is randomly distributed (i.e., not correlated). Generally speaking, the Durbin-Watson statistic will be close to 2.0 if the residuals are not serially correlated. A technique to address serial correlation is the first-order autoregressive correction [AR(1), AR(2).....], which computes the residuals from the regression, and then finds the best prediction of the residual from its own past value. Then it computes a new dependent variable by subtracting the predicted residual from the original dependent variable. This process continues until convergence (getting essentially the same answer each iteration).

Q. Please describe the residential sales forecast.

A. As stated earlier, the residential sales forecast is the product of separate forecasts for residential use-per-account and the number of accounts.

Q. Please describe the residential use-per-account model.

A. The econometric model used to forecast residential use-per-account is

presented in Exhibit No. 110, Schedule 10, page 8. This equation expresses average annual residential gas throughput volumes (Mcf per account) as a function of the economic variables, actual annual heating degree days [PADEGDAYS], residential annual price of natural gas (lagged 10 months) [PARESPRICE(-10)], a linear appliance replacement trend [PATREND] and two autoregressive terms [AR(1) and AR(2)].

The natural gas price is the average revenue per Mcf expressed in 2000 dollars through deflating by the Gross Domestic Product ("GDP") chained price index, as projected in the Blue Chip Economic Indicators, Vol. 31, No. 3, dated March 10, 2006. The natural gas price used is the residential price lagged 10 months. The price variable is specified in this form in order to measure lags in customer response to changes in price. The degree day data are on an average cycle billing month basis, consistent with the Company's volumetric normalization adjustment. The historic residential consumption per account, heating degree days, residential natural gas price data and the trend variable are presented in Exhibit No. 110, Schedule 10, pages 9 through 12.

Q. Please describe the results of the residential use-per-account model.

A. The regression results show that actual heating degree days [PADEGDAYS], 10 month lagged residential natural gas price [PARESPRICE(-10], and the appliance replacement trend [PATREND] are statistically-significant determinants of average use-per-account, with t-

values at 84.36, -4.06, and -14.40 respectively. Corresponding to economic theory, each variable has the expected sign, i.e., positive on degree days, negative on price and negative on appliance replacement trend. The adjusted coefficient of determination, R-squared, is .999, showing the model explains 99.9 percent of the observed variation in use-per-account. The standard error of the regression is 0.23% and the Durbin Watson statistic is 1.83. The residential consumption forecast can be located on Exhibit No. 110, Schedule 10, page 7.

Q. Please describe the residential customer forecast.

A. The number of residential accounts is projected to remain constant through the life of the estimate at the level observed during the twelve months ended December 2005. This projection is conservative because the change in the average number of residential accounts between the forecast and the most recent actual data (twelve months ended March 2006) has been a reduction of 259 accounts. The residential number of accounts forecast can be located on Exhibit No. 110, Schedule 10, page 7.

Q. Please describe the commercial sales forecast.

A. The commercial class, as with the residential class, has separate projections for average annual use-per-account and number of accounts.

Q. Please describe the commercial use-per-account model.

A. The econometric model used to forecast commercial throughput use-per-account is presented in Exhibit No. 110, Schedule 10, page 14. This

equation expresses average annual commercial use-per-account as a function of the economic variables, actual annual heating degree days [PADEGDAYS], commercial annual real gas price lagged 10 months [PACOMPRICE(-10)], trend variable [PATREND] and two autoregressive terms [AR(1) and AR(2)]. As presented in the residential model, the degree day data are on an average cycle billing month basis. The historic commercial consumption per account, heating degree days, commercial natural gas price data and the trend variable are presented in Exhibit No. 110, Schedule 10, pages 15 through 18. The commercial consumption forecast can be located on Exhibit No. 110, Schedule 10, page 13.

Q. Please continue.

A. The regression results show actual heating degree days [PADEGDAYS], the 10 month lagged commercial natural gas price [PACOMPRICE(-10)] and trend [PATREND] are statistically-significant determinants of average use-per-account, with t-values at 33.81, -5.21 and -4.19 respectively. Corresponding to economic theory, each variable has the expected sign, i.e. positive sign on heating degree days, negative on gas price and negative on trend. The adjusted R-squared is .996, showing the model to explain 99.6 percent of the variation in use-per-account. The standard error of the regression is 0.41% and the Durbin Watson statistic is 2.06.

Q. Please describe the commercial customer forecast.

A. The number of commercial accounts is projected to remain constant

through the life of the estimate at the level observed during the twelve months ended December 2005. The change in the average number of commercial accounts between the forecast and the most recent actual data (twelve months ended March 2006) has been a reduction of 26 accounts. The commercial forecasted number of accounts can be found on Exhibit No. 110, Schedule 10, page 13.

Q. Please describe the public authority sales forecast.

A. The public authority class, as with the residential and commercial classes, has separate projections for average annual use-per-account and number of accounts.

Q. Please describe the public authority use-per-account model.

A. The econometric model used to forecast public authority throughput use-per-account is presented in Exhibit No. 110, Schedule 10, page 20. This equation expresses average annual use-per-account as a function of the economic variables, actual annual heating degree days [PADEGDAYS], public authority annual real natural gas price lagged 10 months [PAPUBPRICE(-10)] and one autoregressive term [AR(1)]. The historic public authority consumption per account, heating degree days and public authority natural gas price data are presented in Exhibit No. 110, Schedule 10, pages 21 through 24. The public authority consumption forecast can be located on Exhibit No. 110, Schedule 10, page 19.

Q. Please continue.

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A. The regression results show actual heating degree days [PADEGDAYS] and the 10 month lagged public authority natural gas price [PAPUBPRICE(-10)] to be a statistically-significant determinant of average use-per-account, with a t-value at 13.46 and –4.21, respectively. Corresponding to economic theory, heating degree days has the expected positive sign and price has a negative sign. The adjusted R-squared is .976, showing the model to explain 97.6 percent of the variation in use-per-account. The standard error of the regression is 0.92% and the Durbin Watson statistic is 1.92.

Q. Please describe the public authority customer forecast.

A. The public authority customer forecast is expected to remain constant at the level observed for the twelve months ended December 2005. The change in the average number of public authority accounts between the forecast and the most recent actual data (twelve months ended March 2006) has been a reduction of 2 accounts. The forecasted number of public authority accounts can be found on Exhibit No. 110, Schedule 10, page 19.

Q. Please describe the Small Volume Industrial Service (SVIS) forecast.

A. The SVIS class consists of industrial customers consuming less than 1,000 Mcf per year. The volumetric forecast for SVIS customers is projected at the same level of throughput as observed during the twelve months ended December 2005. The number of SVIS customers is also projected to be the same as observed during the twelve months ended December 2005. The SVIS consumption and number of accounts projection can be found on

Exhibit No. 110, Schedule 10, page 27.

Q. Please describe the Intermediate Volume Industrial Service (IVIS) forecast.

A. The IVIS class consists of industrial customers consuming between 1,000 and 50,000 Mcf per year. The volumetric forecast for IVIS customers is projected at the same level of throughput as observed during the twelve months ended December 2005. The number of IVIS customers is also projected to be the same as observed during the twelve months ended December 2005. The IVIS consumption and number of accounts projection can be found on Exhibit No. 110, Schedule 10, page 28.

Q. How were the transportation volumes estimated for the residential, commercial, public authority, SVIS and IVIS classes?

A. Over the years transportation service to these classes has been increasing in volume. The increase in transportation volumes has generally been a shift from retail sales service. However, most recently, transportation service to these classes has seen a leveling off of volumes. Therefore, transportation volumes to the residential, commercial, public authority, SVIS and IVIS categories reflect the transportation volumes experienced during the twelve month ended December 2005.

Q. Please describe the industrial forecast for accounts consuming greater than 50,000 Mcf per year?

A. All industrial accounts with volumes in excess of 50,000 Mcf per year were forecasted individually.

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

Q. Why were industrial accounts in the greater-than-50,000 Mcf per year category forecasted individually, as opposed to an econometric derivation?

A. The lack of homogeneity renders it unsuitable for econometric forecasting. These larger accounts have different natural gas requirements, applications and alternate fuel-burning capabilities. Consequently, an individual customer forecast approach has been, and continues to be, the most appropriate. Moreover, the individual forecasts we have performed for this group in the past have proven to be quite reliable.

Q. How was the forecast prepared for industrial accounts consuming greater-than-50,000 Mcf per year?

A. The large volume industrial category consists of Large Volume Industrial Service (LVIS), industrial customers consuming between 50,000 and 200,000 Mcf per year, and Large Industrial Service (LIS), which consists of industrial customers consuming greater than 200,000 Mcf per year. Each customer was contacted by the Company's appropriate major account representative of the Energy Services Department, who is the closest liaison between the Company and the customer and is the individual most aware of each customers energy decisions. The customers were asked to estimate their usage, paying particular attention to any events that may alter their estimated future consumption levels. A summary of the individual LVIS / LIS estimates can be located on Exhibit No. 110, Schedule 10, pages 29 through 38.

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

Q. Would you please summarize the results of your forecast?

A. The Company's Pennsylvania Division volumetric forecast is shown on Exhibit No. 110, Schedule 9 for the Future Test Year (twelve months ending January 2007).

Q. Does the Company's sales forecast recognize customer conservation?

A. Yes. The individual forecasts for accounts consuming in excess of 50,000 Mcf per year recognize the most recent energy use decisions of those companies. Conservation is one component of those decisions. In addition, the econometric forecasts of consumption for accounts consuming less than 50,000 Mcf per year recognize conservation.

Q. Do you expect conservation to continue?

A. Yes. Even if Distribution's residential, commercial and public authority customers made no active effort to conserve natural gas, conservation will continue because changes in the standards for construction of buildings and improvements in the efficiency of natural gas furnaces and other gas appliances will result in our customers using less gas over time for equivalent comfort levels and uses.

Q. To what changes in standards of building construction are you referring?

A. Older homes in Distribution's service territory were not constructed using current building practices, and are less air tight and less insulated. As a result, they are generally less energy-efficient than newer homes. Consequently, over time, as more new homes are built and are occupied by

Distribution's customers, and as older homes are renovated or abandoned, the average annual volume of gas per account used by residential customers for space heating will decline.

Not only are energy efficient construction practices good business for builders and developers, because home purchasers desire such features, they are also required by law. In Pennsylvania, The Building Energy Conservation Act of December 15, 1980, 35 P.S. § 7201.010 et seq. and regulations of the Department of Community Affairs, at 16 Pa. Code § 30.1 et seq., and the Department of Labor and Industry, at 34 Pa. Code § 38.1 et seq. mandate that new homes, schools and office building meet modern energy efficient construction standards. The new standards for energy efficiency are applicable not only to new buildings but also to renovations of existing buildings.

Q. What improvements in natural gas appliances have occurred?

Not only are buildings, themselves, becoming more energy-efficient but also equipment used for space-heating is becoming more energy efficient. For example, high-efficiency furnaces can convert 92 percent or more of the heating value of natural gas into space heat. Although these extremely efficient models are more expensive than standard furnaces, even standard furnaces convert about 80 percent of the heating content of natural gas to space heat. In contrast, typical furnaces sold two decades ago converted only about 70 percent of the heating content of natural gas into space heat.

Over time, Distribution's residential customers are converting to more energy-efficient space-heating equipment. The average service life of a furnace is approximately 17 years and about 97% of Distribution's 197,792 residential customers have gas as their primary source of heat. Therefore, approximately 11,286 (197,792 residential customers * 97% heating saturation ÷ 17 years) existing gas furnaces are replaced annually by Distribution's residential heating service customers. Such replacements are significant because 79 percent of Distribution's normalized residential use per customer was for space heating (80.002 Mcf of 101.553 Mcf) for the twelve months ended January 2006.

If Distribution's residential customers that are replacing old furnaces purchased standard minimum efficiency furnaces (80 percent efficient), Distribution's sales volumes to residential customers would be reduced by 123,651 Mcf. The following calculation illustrates this reduction:

Let X = average annual heating load per residential customer with standard minimum efficiency furnace (80%).

X = 80.002 Mcf (normalized residential space heating usage) * 70% (average furnace efficiency) ÷ 80% (standard minimum furnace efficiency) = 70.002 Mcf per year.

Conservation per customer = 80.002 Mcf - 70.002 Mcf = 10.000 Mcf.

Total annual conservation = 10.000 Mcf per new standard minimum efficiency furnace * 11,286 new furnaces replacements = 112,860 Mcf per

year.

Even greater reductions in consumption would occur if residential customers replaced their heating equipment with high efficiency furnaces (92 percent efficient). The following calculation illustrates this reduction:

Let X = average annual heating load per residential customer with the high efficiency furnace (92%).

X = 80.002 Mcf (normalized residential space heating usage) * 70% (average furnace efficiency) ÷ 92% (high furnace efficiency) = 60.871 Mcf per year.

Conservation per customer = 80.002 Mcf - 60.871 Mcf = 19.131 Mcf.

Total annual conservation = 19.131 Mcf per new high efficiency furnace * 11,286 new furnaces replacements = 215,912 Mcf per year.

Based on the relatively modest equipment cost differential between an 80 percent efficient furnace ($660) and a 92 percent efficient furnace ($945), the payback period for the more efficient equipment is extremely short. The incremental consumption savings between the 80% efficient furnace v. 92% efficient furnace is 9.131 Mcf per year (70.002 Mcf – 60.871 Mcf) * $16.70 per Mcf (average of winter 2005-2006 $/Mcf [November 2005 – March 2006]) = $152.49. The actual furnace cost differential $285 ($945 - $660) / $152 (annual savings) = 1.9 years simple payback.

Similar advances in efficiency are offered through the replacement of water heaters. Contemporary water heaters, like contemporary furnaces,

are more efficient than older models. Therefore, simply as a result of routine replacement of older water heaters with more efficient water heaters, Distribution's annual sales to residential customers for water heating will be reduced. Another example of conservation through normal appliance replacement is ranges. Older gas ranges with pilot lights use more gas than pilot less ranges therefore, the routine replacement of older, less efficient ranges reduces Distribution's residential sales volumes. Similarly, older clothes dryers with pilot lights use more gas than pilot less clothes dryers. Consequently, through the normal and routine replacement of older, less-efficient clothes dryers, Distribution loses annual sales volumes.

As explained above, routine replacement of gas-fired heating equipment and appliances results in lost annual sales volumes, due to conservation, of at least 112,860 Mcf (furnaces only). Assuming customers replace their equipment with a high efficiency (92%) furnace the result is a loss in annual sales volumes of 215,912 Mcf (furnaces only).

Thus, sales to residential customers can be expected to decline from 0.57 Mcf to 1.09 Mcf per customer per year (112,860 Mcf ÷ 197,792 residential customers = 0.57 Mcf; 215,912 Mcf ÷ 197,792 residential customers = 1.09 Mcf) simply due to the replacement of furnaces.

Q. What other type of actions would have a downward effect on residential consumption?

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A. Any improvement to a residential envelope, i.e. insulation, replacement doors and windows, storm doors and windows, weather stripping and any other threshold improvement. Further, automatic set back thermostats, or for that matter any manual adjustments to a standard thermostat would also reduce residential consumption. Additionally, as discussed earlier, the average new home is more efficient than the average existing home and likely even more efficient than an existing home lost to demolition or attrition. In fact, the average normalized consumption (twelve months ended March 2006) for new residential accounts connected between January 1999 and March 2005, is 92.207 Mcf per account, compared to the average normalized consumption (twelve months ended March 2006) for existing residential accounts of 100.034 Mcf per account, for a variance of 7.827 Mcf per account. Put another way, the average existing residential customer consumes approximately 8.5% more gas than a new residential customer.

Q. Does this conclude your testimony?

A. Yes, at this time.