OSBA STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-00061493
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	:	

Direct Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Office of Small Business Advocate

ORIGINAL

Date Served: September 6, 2006

Date Submitted for the Record: _____

ORIGINAL

DIRECT TESTIMONY OF ROBERT D. KNECHT

1. Introduction and Overview

Q. Please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am a Principal and the Treasurer of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. As part of my consulting practice, I have prepared analyses and expert testimony in the field of regulatory economics on a variety of topics. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and an M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance. I am appearing in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). My résumé and a listing of expert testimony that I have filed in utility regulatory proceedings are attached in Exhibit IEc-1.

Q. Please describe the purpose of this testimony.

A. I was retained by the OSBA to review and analyze the base rates filing submitted by National Fuel Gas Distribution Corporation ("NFGD," "Distribution," or "the Company"), that requests a rate increase of $25.9 million for a test year ending January 31, 2007. Based on a preliminary review, and in conjunction with OSBA, I identified certain aspects of NFGD's filing that had the potential to result in excessive or unreasonable tariff rates for small business customers. I then evaluated those issues in more detail. To the extent that I concluded that NFGD's proposals in those areas were not consistent with sound economics and regulatory policy, I present my analysis and conclusions in this testimony. However, due to time and budget constraints, I did not conduct an exhaustive review of all aspects of NFGD's filing. To the extent I do not address a subject in this testimony, it cannot be inferred that I agree with the Company's proposal.

Q. Please summarize your conclusions and recommendations in this testimony.

A. My conclusions and recommendations are as follows:

1. For the purposes of this proceeding, I conclude that small business customers are served under four rate classes in NFGD's service territory:

   - Small Commercial and Public Authority Service, with customers consuming less than 250 Mcf per year ("SC&PA LE250");
   - Small Commercial and Public Authority Service, with customers consuming more than 250 Mcf per year ("SC&PA GT250");
   - Large Commercial and Public Authority Service ("LC&PA"); and,
   - Small Volume Industrial Service ("SVIS").

2. NFGD's proposed return on equity of 12.25 percent and its proposed return on rate base of 9.48 percent substantially exceed the cost of capital for a natural gas distribution company ("NGDC") that is exposed to NFGD's gas distribution business risk. Based on "top-down" and "bottom-up" analyses, I recommend that the return on equity be set no higher than 10.25 percent, and that the return on rate base be set no higher than 8.27 percent. I calculate that making the adjustment to an 8.27 percent return on rate base would reduce the Company's rate increase by $5.9 million. A reasonable range for the allowed return on equity is 9.75 to 10.25 percent, and for weighted average return on rate base it is 8.03 to 8.27 percent.

3. In its filing, NFGD forecasts that it will experience significant declines in gas use per customer for its residential and commercial customers, compared to the forecasts in its last base rates case for test year ending May 2005. This reduction contributes significantly to NFGD's need for a rate increase. While my analysis of this topic is not complete, NFGD's proposed reduction in the average size of its smallest commercial customers appears to be excessive. If so, NFGD's proposed rates for those customers should be adjusted downward.

4. None of the four cost of service study ("COSS") methodologies filed by NFGD in this proceeding represents a sound basis for allocating costs to the various rate classes in this proceeding. However, developing a corrected, accurate version of a COSS for NFGD is beyond the scope of this testimony. Nevertheless, using a simple average of NFGD's four methodologies should produce a reasonably

accurate estimate of the cost of service for each rate class. I have therefore used that average in developing my recommendations for assigning rate increases among the rate classes and for developing tariff charges for the rate classes under which commercial customers take service.

5. Despite having filed four COSSs, all of which show that the class rates of return for all of the four small business customer classes exceed the system average, NFGD proposes to assign above system average rate increases to the SC&PA and LC&PA rate classes. NFGD's proposal is not consistent with sound regulatory principles, and it is obviously inequitable to require that subsidies from small business customers increase. In this testimony, I propose a "first dollar rate relief" ("FDR") mechanism to achieve a more reasonable sharing of the rate increase among the various rate classes.

6. I recommend that NFGD's proposed revenue decoupling mechanism ("RDM") not be approved in this proceeding. First, this mechanism is not necessary to encourage ratepayer conservation -- ratepayers already face strong economic incentives to conserve, and businesses who supply insulation, set-back thermostats and other conservation technologies have incentives to encourage the use of their products. Second, this mechanism is an example of single-issue ratemaking, adoption of which would create a risky precedent for other utilities in Pennsylvania. Third, this mechanism will have the effect of deferring rate cases that NFGD would otherwise need to file, thereby making it much more difficult to move rates for small business customers in line with allocated costs. It will therefore have the effect of perpetuating the subsidy from those rate classes. Until such time as rates for small business are cost-based, this proposal is unduly discriminatory, in addition to it other flaws.

7. NFGD's proposal to adopt a merchant function charge ("MFC") to recover certain costs that are related to gas sales customers only from sales customers (and not transportation customers) is consistent with sound regulatory principles. However, establishing that charge as a percentage of the purchased gas charge may cause this

proposal to run afoul of legal proscriptions against automatic adjustments for uncollectibles costs.

8. NFGD's proposal to establish a pilot program to purchase receivables from alternative natural gas suppliers ("NGSs") in order to encourage competition is not necessarily unreasonable, although it has aspects that merit review.

9. NFGD's proposal to establish seasonal rates for purchased gas costs ("PGCs") is not, in concept, unreasonable. However, NFGD's proposed method for seasonalizing costs to develop the proposed seasonal rate differentials is not consistent with cost causation. As efforts to correct NFGD's inaccurate cost allocation are beyond the scope of this testimony, I recommend that this proposal be rejected pending the development of a more accurate cost seasonalization methodology.

10. NFGD proposes two alternative rate design packages for C&PA customers, one that is linked with its seasonal PGC rate proposal and one that is generally consistent with its existing tariff structure. I recommend that a number of aspects of both proposals be modified. First, the proposed increase of 62.5 percent for the customer charge for SC&PA LE250 customers is excessive, for reasons of both gradualism and cost of service. Second, NFGD's proposed increases for LC&PA sales customers are much higher than its proposed increases for LC&PA transportation customers, although NFGD has no cost justification for the difference. Third, in its seasonal rate designs for both SC&PA rate classes, NFGD's proposals to significantly increase the first block charges and significantly reduce the tail block charges are not consistent with any cost evidence on the record.

Q. Can you provide a little background regarding the size and load patterns for small business customers who take service from NFGD?

A. NFGD's commercial customers are those who participate in a wide variety of business activities, including wholesale or retail trade, agriculture, forestry, fisheries, transportation, communications, sanitary services, finance, insurance, and real estate. Religious and not-for-profit organizations also take service under this tariff category. Public authority customers are those entities that are financed by public funds. The

distinction between LC&PA and SC&PA customers is NFGD's requirement that LC&PA customers consume at least 1,000 Mcf per year. NFGD further segregates its SC&PA customers into those using less than 250 Mcf per year, and those using more than 250 Mcf per year.

Industrial customers are defined as customers who upgrade raw material into other products, and include both manufacturing and mining operations.

Table IEc-1 below summarizes some of the key characteristics of these classes:

Table IEc-1
Overview of Rate Classes that Include Small Businesses

	SC&PA LE 250	*SC&PA GT 250*	*LC&PA*	*SVIS*
Number of Customers	8,974	4,144	2,270	187
Avg Mcf per Year	108	446	2,774	426
Load Factor (%)	24.4%	24.5%	27.8%	49.7%
Avg Curr Dist'n Bill ($/Mo.)	$39	$97	$424	$136
Avg Curr Dist'n Rate ($/Mcf)	$4.30	$2.61	$1.84	$3.83
Transport Customers (%)	<0.1%	1.8%	33.6%	0.5%
Transport Volumes (%)	<0.1%	2.9%	73.2%	2.6%

Based on this information, it is likely that most of the customers in these classes, with the exception of the SVIS customers, use natural gas for space heating as evidenced by the relatively low class load factors.[1] Even as the customer size increases from the smaller SC&PA classes to the LC&PA class, the average class load factor increases only slightly.

Also, virtually all of the smaller customers take gas sales service from NFGD, while the larger customers, particularly within the LC&PA class, are more likely to be transportation customers. These transportation customers primarily take NFGD's Monthly Metered Transportation ("MMT") service, although there are some Daily Metered Transportation ("DMT") customers. Finally, note that there is a very wide range of customers and types of businesses within and among these rate classes. The smallest customers consume an average of 5 Mcf per month, while the largest LC&PA customers have average monthly loads in excess of 5,000 Mcf per month.

[1] In the current filing, the load factor for SVIS is more than double that from the last filing. However, based on my experience, the value reported in the current filing is more reasonable for customers classified as "industrial."

2. Cost of Capital

Q. Please summarize your analysis of NFGD's claimed rate of return.

A. My analysis of NFGD's claimed overall rate of return consists of three components:

- A "top-down" review of NFGD's proposed return on equity, based on various external sources regarding expectations for market and industry returns;
- A "bottom-up" evaluation of NFGD's return on equity, that relies primarily on NFGD's expert witness Mr. Hanley for methodology and assumptions, but makes adjustments to key parameters; and,
- A review of NFGD's proposed capital structure.

I have not evaluated NFGD's claimed cost of debt, and I therefore have used NFGD's cost of debt proposals for making my overall return on rate base calculations.

Q. Have you performed a detailed review of the analyses presented by NFGD's expert witness Mr. Hanley that lead to his recommendations?

A. I have replicated most of Mr. Hanley's Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM") and Risk Premium ("RP") analyses. Further, I have prepared my own version of those analyses, using assumptions that I believe to be reasonable. I have not analyzed Mr. Hanley's comparable earnings methodology in detail, because the mix of firms used by Mr. Hanley is not comparable to a NGDC, and the forecast earnings levels appear to be biased upwards.

In addition, I reviewed Mr. Hanley's analysis in support of his proposal for a deemed capital structure for NFGD.

My details regarding the cost of equity capital and the capital structure of the sample firms calculations are reported in my electronic workpapers.

2.1 Top-Down Comparisons

Q. Please describe your first top-down comparison of NFGD's proposed return on equity with external standards.

A. First, I compare the return on equity investments that NFGD expects to earn on its pension fund assets with the return the Company is requesting on its utility equity. It is important to recognize that the higher the assumed return on pension assets, the *lower*

will be the cost to ratepayers. Conversely, the higher the requested return on utility equity, the *higher* will be the cost to ratepayers. Both calculations rely, at least in part, on assumptions about overall stock market returns. Simple fairness suggests that comparable market assumptions be used in both sets of calculations. Moreover, NFGD's actuaries who make the assumptions about expected returns have much lower economic incentives to set expected returns above or below actual market expectations than do participants in an adversarial regulatory proceeding.

I recognize that the return on equity figures for NFGD and for return on NFGD's pension equity investments are not directly comparable for a variety of reasons. However, the key point to recognize is that pension funds are generally invested in a riskier portfolio of equities than those for which NFGD is requesting a return. Pension funds typically invest in a well-diversified portfolio of equities, which implies that the expected equity returns for a pension fund would be similar to expected overall market returns. Utility stocks, by contrast, exhibit lower risk properties than those of the average common stock, primarily because utilities are protected by regulation from many of the vagaries of competitive markets. Thus, before transaction costs, it is reasonable to expect that the average expected return for pension fund investments would be substantially higher than that necessary to finance utility assets.

Q. How does NFGD's requested return on equity compare with the assumptions used by NFGD's actuaries ("Mercer") in developing their proposed return for the Company's pension fund investments?

A. In the response to OSBA-I-7, Mercer indicates that its return on equity assumptions are based on compounded average equity returns of 8.16 percent and arithmetic average equity returns of 9.70 percent.[2] While Mercer uses the compounded average for determining its expected return on pension fund assets, it also assumes that returns will be higher than the median (in the 60th to 65th percentile). My calculations indicate that the implied return on equity used by Mercer is a little below the arithmetic average figure of 9.70 percent reported in OSBA-I-7.

[2] Referenced interrogatories are attached to this testimony as Exhibit IEc-2.

Of course, both of Mercer's values are far below the 12.25 percent requested by NFGD, despite the fact that the mix of equities in which NFGD's pension fund is invested are likely to have higher risk characteristics than NFGD equity.

It should also be noted that Mercer assumes a much lower risk premium for equity investments than that used by NFGD. Mercer's assumed return on fixed income investments (arithmetic average) is 5.30 percent, implying that its risk premium for average-risk equities is 440 basis points (4.4 percent). By comparison, NFGD's proposed return on equity is 12.25 basis points compared to the current yield on investment grade bonds in the range of 5.6 to 6.1 percent, which implies a risk premium of at least 615 basis points.

Q. Has any other regulatory commission considered the implications of discrepancies between the assumptions used by utility cost of capital experts and utility actuaries?

A. In a rate filing by Connecticut Light & Power ("CL&P"), the Connecticut regulator concluded:

> *Finally, expectation[s] for all stocks have generally declined since the market downturn from 2000 to 2002. Most analysts now estimate returns more in line with historical averages or lower. This is reinforced by CL&P's own testimony regarding its pension plan. CL&P testified that long-term expectation for its overall pension return, which is approximately 70% equity, should be lowered from 9.25% in 2002 to 8.75%.*[3]

The regulator approved a cost of equity capital of 9.85 percent, compared to the 10.75 percent requested by CL&P.

Q. How do Mercer's return on equity assumptions compare with those used in NFGD's last base rates case?

A. At the time of NFGD's last base rates case, Mercer assumed that the arithmetic average returns used to derive NFGD's pension fund returns for equity investments would be between 10.13. In the current case, Mercer's assumption is an equity return of 9.70 percent, some 43 basis points lower. By contrast, NFGD's proposed return on equity has

[3] In the Matter of an Application of the Connecticut Light and Power Company to Amend its Rate Schedules, 229 P.U.R. 4th 380, Ct. D.P.U.C. Docket No. 03-07-02 (Dec. 17, 2003).

increased from 11.875 percent requested in the last case compared to 12.25 percent in this case.

In short, NFGD's proposal relative to the last base rates case is to increase the revenue requirement associated with a lower expected return on pension equities and to also increase the revenue requirement associated with a higher claimed rate of return for its own equity. Both factors add to NFGD's proposed increase in this case.

Q. Have you reviewed any independent estimates of the cost of common equity for NGDCs?

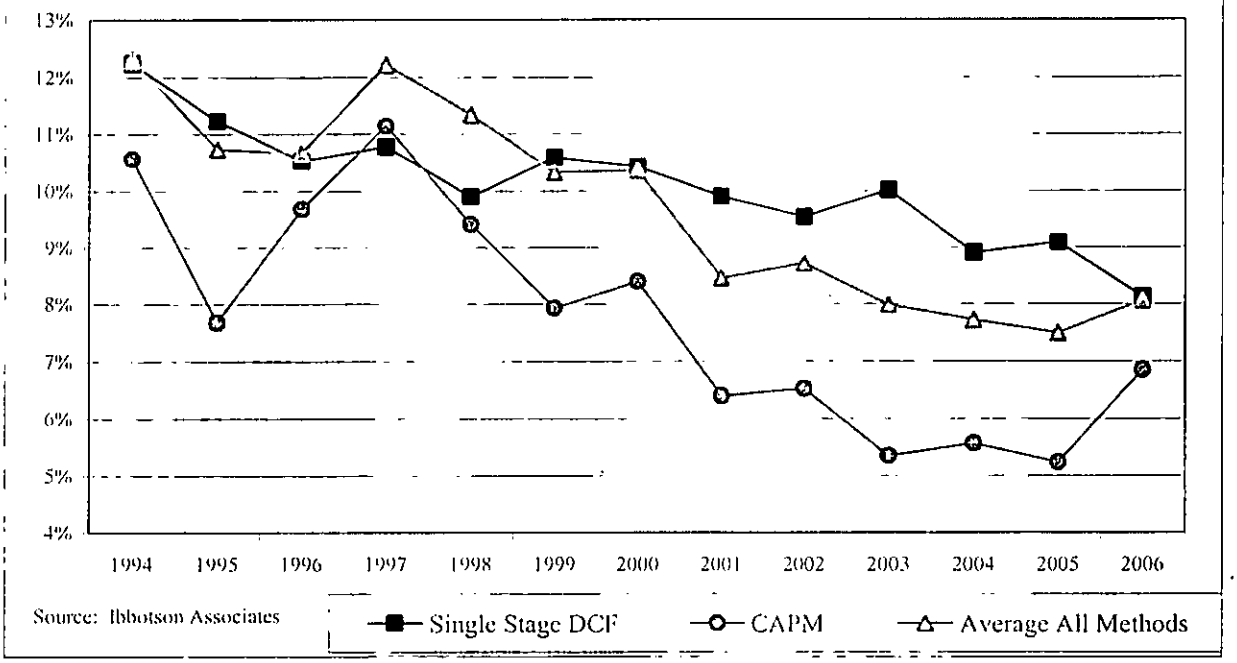
A. Yes I have. Ibbotson Associates prepares estimates of the cost of equity capital for various industries based on a variety of methodologies, including two methods used by Mr. Hanley, namely the capital asset pricing model ("CAPM") and single-stage discounted cash flow ("DCF") methodologies. Because Ibbotson Associates is not representing either the utility or the ratepayers in this proceeding, there is less reason to be concerned about potential bias in its calculations.

The Ibbotson Associates' estimates are presented in the Cost of Capital Yearbook, and they are based on methods that are similar to those used by NFGD's expert Mr. Hanley to estimate the cost of equity capital for firms in the natural gas distribution industry (SIC 4924). The CAPM method reported by Ibbotson Associates relies on adjusted Betas (as does Mr. Hanley, albeit using a different adjustment methodology), long-term yields on government bonds (as does Mr. Hanley), and the long-term actual equity premium over long-term government bonds. The single-stage DCF approach uses growth-adjusted dividend yields (as does Mr. Hanley) and earnings forecasts from institutional brokers ("I/B/E/S"). As shown in Figure IEc-1 below, Ibbotson Associates' DCF analysis indicates that the cost of equity capital for NGDCs declined steadily between the mid-1990s, and is now in the 8.0 percent range. The Ibbotson Associates CAPM analysis also suggests that the cost of equity capital for NGDCs has generally been declining, with an uptick in 2006, and that the CAPM analysis produces a distinctly lower cost of capital than the DCF methodology.

Figure IEc-1 below compares the CAPM and DCF costs of equity capital for the natural gas distribution industry as estimated by Ibbotson Associates for the past ten years.

Because Ibbotson Associates also develops cost of equity capital based on the 3-Factor Fama-French model, and the 3-Stage DCF approach, I have also included an average of all of their equity costs in Figure IEc-1. These other methodologies also imply that NFGD's proposed return on equity of 12.25 percent far exceeds the cost of capital for this industry.

Figure IEc-1
Median Historical Cost of Equity Capital
Natural Gas Distribution Industry (SIC 4924)



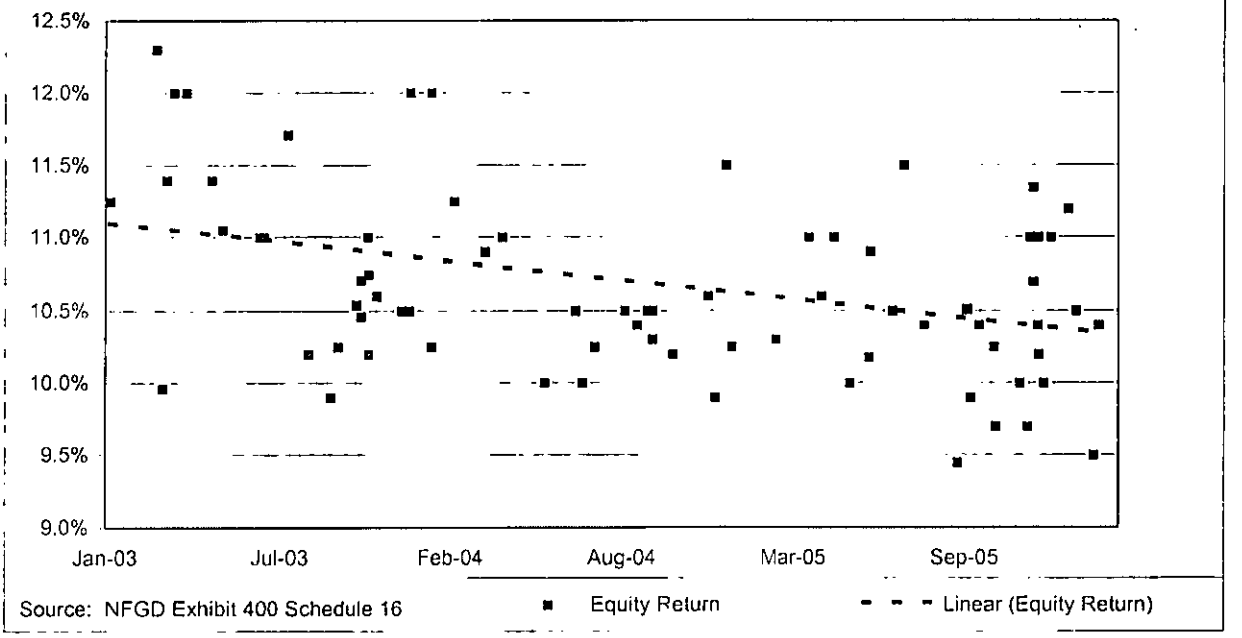
Q. Did you perform any other top-down analyses?

A. Yes I did. Mr. Hanley presents an exhibit that reports the allowed rates of return on equity for other NGDCs in the United States. I have presented that data in graphical form in Figure IEc-2 below.[4] As shown in that figure, Mr. Hanley's data suggest first that virtually all allowed rates of return for NGDCs in the last two years lie between 9.5 and 11.5 percent. Thus, NFGD's proposed return of 12.25 percent is well outside the recent range of equity cost awards. Moreover, Mr. Hanley's data indicate that, although there is

[4] Note that Figure IEc-2 also includes authorized returns on equity reported by Mr. Hanley in NFGD's last base rates case.

significant variation, there has been a declining trend in allowed rates of return on equity over the past three years. Based on this trend analysis, a typical NGDC return on equity award at present would be approximately 10.25 percent.

Figure IEc-2
Trends in Allowed Equity Returns



Q. What do you conclude from your top-down review of NFGD's proposal for return on rate base?

A. From this review, NFGD's proposed return on equity of 12.25 percent is excessive. It is beyond the high end of the range of recently allowed equity returns, and it is considerably higher than that implied by the market returns on equities assumed by NFGD's actuaries, even without adjusting for the relatively lower risk. Further, it is considerably higher than cost of equity estimates prepared by an independent analytical firm that uses methodologies very similar to those employed by NFGD's expert.

2.2 Risk Premium and CAPM Analyses

Q. Can you describe the basic approach for developing a cost of equity capital using the RP and CAPM approaches?

A. It is economic doctrine that the cost of capital for any particular form of investment must recognize the riskiness of that investment. As investors are assumed to be "risk averse,"

they require a higher *expected* return on riskier assets than on low-risk assets. That is, the investor will expect to earn more from an investment option that has a potential range from negative 10 percent to 30 percent than from an investment option that has a potential range from 5 percent to 15 percent.

Therefore, the expected return on equity investments must be higher than the returns on such relatively low-risk investments as government securities or high-grade corporate bonds. Similarly, the expected return on regulated utility equity investments should be lower than the expected returns on an average stock investment, because regulated utilities are generally lower-than-average risk investments.

The RP and CAPM approaches to deriving the equity cost of capital are both techniques for measuring the premium required by investors to take on the risk of the stock investment, relative to some low risk cost of capital.[5] Both methods begin by identifying a relatively low-risk interest rate, to which is added a premium to reflect the higher riskiness of the equity investment.

For his RP analysis, Mr. Hanley develops estimates of two different forms of risk premiums, one based on a risk-adjusted overall market risk premium and one based on a utility-specific risk premium.

In the overall market RP approach, Mr. Hanley's method is very similar to the CAPM approach. In both the market RP and CAPM models, Mr. Hanley uses the factor "Beta" to assess the riskiness of a regulated NGDC investment relative to the overall riskiness of average market investments. As discussed further below, Beta measures the relative riskiness of a particular stock compared to the riskiness of all stock investments.

In the utility risk premium analysis, Mr. Hanley uses a premium based on actual utility returns relative to the base interest rates.

[5] Note that the RP and CAPM approaches suggest that investors make a tradeoff between low-risk and high-risk investments. However, investors have also made a tradeoff between investing and consuming, suggesting that the expected inflation-adjusted rate of return for all kinds of investments is a key consideration for investors as well.

Thus, the RP and CAPM models take the following form:

Market RP and CAPM RoE = Interest Rate + (Utility Beta*Market Premium)

Utility RP RoE = Interest Rate + Utility Risk Premium

Simple as these equations seem, however, each parameter in the equations is subject to significant analytical scrutiny and debate.

The key issues for interest rates are whether to use short-term or longer-term rates, and how to incorporate forecasts for interest rate changes.

The market risk premium should reflect current expectations of what kind of risk premium investors require in order to make equity investments. While it is common to use historical risk premiums as part of the process, most analysts (including NFGD's expert Mr. Hanley) believe that current expectations for market returns are lower than historical observations. However, how current expectations are developed can be a matter of significant debate.

Moreover, estimating the relative riskiness of NFGD stocks compared to average market stocks, namely the computation of Beta, can be performed using a variety of analytical and adjustment techniques. I briefly review each of these issues below.

2.2.1 Interest Rates

Q. What interest rates are used in the CAPM and RP methods?

A. The CAPM specifies that a "risk-free" rate be used. It is common practice to use the interest rate on U.S. government Treasury securities for the risk-free rate. For the market RP, Mr. Hanley uses the return on high-grade corporate bonds; for the utility RP analysis, he uses return on A-rated utility bonds. To develop the prospective interest rate values, Mr. Hanley averages six quarters of the experts' forecasts that were available to him at the time he filed his testimony, beginning with the second quarter of 2006.

Q. Have current interest rates shifted since Mr. Hanley filed his testimony?

A. Yes, to a certain extent. Short-term interest rates have risen modestly, while longer-term rates have declined slightly. For that reason, in my RP and CAPM analyses, I have generally relied on more recent interest rates in my calculations than those used by Mr.

Hanley. A graphical depiction of the longer term pattern of short-term and long-term interest rates is included in my workpapers.

Q. Is there anything particularly significant about the current market situation for interest rates in preparing utility cost of equity estimates?

A. Yes. One common method for developing an equity cost of capital is to estimate the risk premium by looking at the historical relationship between equity returns and interest rates, and then applying that premium to current interest rates.

In his CAPM analysis, Mr. Hanley uses a market risk premium relative to 20-year Treasury bonds, and in his RP analysis, Mr. Hanley uses a market risk premium relative to 20-year corporate bonds. For much of his analysis, Mr. Hanley relies on the historical relationship between equity yields and these bond yields. Mr. Hanley uses no short-term interest rates or historical premiums over short-term rates at all.

One issue that is associated with using only historical market premiums relative to *longer-term* bonds is that the current yield curve is relatively flat. That is, the current difference between longer-term yields and short-term yields is relatively low by historical standards -- in fact, the yield curve is slightly inverted. For example, the yield at this writing on 20-year Treasury bonds is 5.03 percent, compared to 5.10 percent for 3-month Treasury bills, a spread of negative 7 basis points. Over the 1926 to 2005 period reported by Ibbotson Associates, that spread was 140 basis points. Thus, use of historical premiums relative to shorter-term bonds will produce higher expected returns on equity than using premiums relative to short-term bonds under current market conditions.

Q. Is Mr. Hanley's approach of using RP and CAPM analyses that only measure returns relative to longer-term interest rates reasonable in this case?

A. I do not believe so. The literature indicates that the risk-free rate used in CAPM calculations should at least consider the short-term risk-free rate. First, Ibbotson Associates credibly argues that the risk-free rate should reflect the investment horizon.

The horizon of the chosen Treasury security should match the horizon of whatever is being valued.[6]

As NFGD has filed three base rates cases in the past five years, use of a short-term risk-free rate and associated market premiums should be considered. Second, Dr. Morin's treatise indicates, "In practice, sensitivity analysis employing various input values for the risk-free rate can produce a reasonably good range of estimates of equity costs."[7] For that reason, I consider the implications of the CAPM using both short-term and longer-term risk premiums.[8]

Q. How did you develop short-term interest rates for your CAPM analyses?

A. Market expectations for changes in the yield curve for Treasury securities are currently quite flat (and even slightly inverted), suggesting that there is no market expectation that interest rates will rise in the future. I therefore rely only on the current yield on 3-month U.S. Treasury Bills of 5.10 percent.

Q. Please contrast your approach for developing longer-term interest rates with that used by Mr. Hanley.

A. Mr. Hanley generally relies on an average of the six-quarter forecast for bond yields available at the time he filed his testimony, beginning with the second quarter of 2006. For Aaa-rated corporate bonds, that forecast implies a yield of 5.9 percent. Because longer-term interest rates have declined since that time, and because the yield curve is currently flat, I generally rely on current interest rates. For Aaa-rated corporate bonds, that rate is now 5.6 percent. However, the interest rate premium for Aaa-rated securities above Treasury securities is currently a little below historical standards. Thus, in deriving the expected future returns for Aaa-rated securities, I use the current 20-year

[6] Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2004 Yearbook, Ibbotson Associates, 2004, page 53.

[7] Regulatory Finance: Utilities' Cost of Capital, Morin, Roger A., Public Utilities Reports, Inc., 1994, page 309.

[8] It should be noted that the use of short-term risk premium models will *increase* my estimated cost of equity capital relative to Mr. Hanley's methods, all other factors being equal. Of course, in NFGD's last base rates case, the situation was reversed. I therefore have continued to use both approaches in my risk premium analysis.

Treasury bond rate plus the historical premium for Aaa-rated securities. In the end, I use an interest rate for corporate bonds that is similar to that used by Mr. Hanley.

Q. How does Mr. Hanley estimate the total market risk premium for equities?

A. Mr. Hanley generally uses two approaches in developing his market risk premiums in the CAPM and RP analyses. First, he uses long-term historical arithmetic averages, based on information published by Ibbotson Associates. For CAPM analysis, that premium is a long-term equity return of 12.3 percent less the long-term average risk-free rate of 5.2 percent, yielding 7.1 percent. His second method is to use the forecast return on the market as implied by a forecast from Value Line, which he calculates as implying a market return for the next three to five years as being 10.18 percent.[9] For the CAPM analysis, he deducts the forecast long-term Treasury bond rates of 5.05 percent, to get a prospective market risk premium of 5.13 percent. Mr. Hanley then averages the 5.13 percent and the 7.1 percent to produce a CAPM risk premium of 6.12 percent.

His approach for the RP analysis is very similar, except that the premiums are measured relative to corporate bond yields.

Q. Do you have any reason to believe that Mr. Hanley's market risk premium metrics are excessive?

A. Yes, albeit by much less than in the last NFGD base rates case. In his averaging calculation, Mr. Hanley essentially concludes that the expected return on market investments will be almost 100 basis points lower than the historical average. There are several reasons why the current expected market premium may be lower:

- The riskiness of bonds has increased relative to the riskiness of stock investments;
- The increasing life expectancy of investors has increased the investment term for many investors, making longer term risky investments more attractive;
- Technological innovations have made stock market investments much more liquid and much less administratively costly than they were historically. Investors can now access a fully diversified market portfolio (index fund) with relatively small investment amounts for administrative costs of only 10 basis points; and

[9] In NFGD's last base rates case, Mr. Hanley derived this value as 12.19 percent.

- Recent reductions in the federal individual tax rates for dividends and capital gains improve the net returns on market investments for investors subject to income taxes, thereby implying that these investors now require a lower pre-tax return than they required previously.[10]

Professors Brealey and Myers agree that future expected rates are likely to be lower than historical averages, suggesting a discount of 70 to 350 basis points,[11] implying a risk premium range of 4.1 to 6.9 percent (over 10-year Treasury securities).

In addition, NFGD's actuaries currently assume that the equity market return is 9.70 percent, implying a premium over current 20-year Treasury securities of 4.7 percent.

Q. How did you develop market risk premiums for your analysis?

A. I made calculations similar to those made by Mr. Hanley, averaging the long-term historical market risk premium and a measure of current expectations. Like Mr. Hanley, I use a simple average of the long-term historical risk premiums, based on the 1926 to 2005 Ibbotson data. However, for current expectations, I use the premium as implied by NFGD's actuaries. For the CAPM analysis, the historical risk premium analysis implies a premium over long-term Treasury securities of 7.1 percent, and a premium over short-term Treasury securities of 8.5 percent. For current expectations, the Mercer expected return on the market implies a market risk premium of 4.7 percent over long-term risk-free rates, and a premium of 4.6 percent over short-term risk-free rates.

For the RP analysis, I adjusted the market premiums to be consistent with the long-term differences between corporate or utility bonds and Treasury securities.

Q. Did you make any adjustments to Mr. Hanley's utility risk premium calculations?

A. In his market-based risk premium analysis, Mr. Hanley recognizes that future expectations for investment returns will be below those experienced historically. I make

[10] Many stock market investors are not subject directly to dividend and capital gains taxes, because the investments are made by pension plans or tax-deferred defined contribution retirement plans. However, this reduction in tax rates improves the net returns from the market for those investments that produce returns subject to income taxation.

[11] Principles of Corporate Finance, Brealey, Richard A. and Stewart C. Myers, Sixth Edition, 2000, pages 156-160.

a similar adjustment, although I use modestly different values regarding the magnitude of the effect. However, in the utility risk premium analysis, Mr. Hanley uses only the historical premium return on utility stocks. This historical premium is overstated as a measure of future expectations, for all of the reasons cited earlier regarding market returns. Moreover, the historical utility return may also reflect a riskier mix of utility businesses than NGDCs, because fully integrated utilities were subject to other risks.[12] For that reason, I have also included an expected future utility risk premium in my calculations. To estimate that future utility risk premium, I made an adjustment that is consistent with my adjustment to the market risk premium.

2.2.3 Beta

Q. What is Beta?

A. Beta is a measure of the risk of an individual stock relative to that of all risky investments. All investment returns are subject to risk. However, an investor can reduce his risk by diversifying his investment into a wide variety of types of investments. Under CAPM theory, the only investment risks that are not diversifiable are those that are correlated with the overall market. The more that the return from an individual stock is correlated with the market, the riskier it is.

Beta is the measure of that non-diversifiable risk in the CAPM. A stock with a Beta of 1.0 has the same riskiness as that of the market as a whole. Betas below 1.0 are relatively low risk stocks, while Betas above 1.0 are higher risk stocks. In theory, stock returns that are negatively correlated with the market exhibit a negative Beta, though there are very few examples of such securities.

Q. How does Mr. Hanley develop estimates for Beta, in preparing his CAPM analyses?

A. Mr. Hanley uses the average "Value Line Adjusted Beta" for his 4-firm sample, and he uses the average of eight of the nine Betas in his 9-firm sample group. He excludes one observation because it produces a cost of equity capital that he deems to be too low to be reasonable.

[12] For example, integrated electric utilities were subject to the risk that major plant investments could be disallowed for imprudence, as in the case of nuclear power plants.

Q. How does Value Line develop "Adjusted Betas" for each company?

A. Value Line's documentation indicates that it computes unadjusted Betas by performing a regression analysis over five years of monthly data, to determine the correlation between market return for the stock and total market return, measured by return on the New York Stock Exchange Composite. Value Line then applies an adjustment to the Betas to reflect its hypothesis that, over time, individual company Betas move toward unity. The formula for this adjustment (the "Blume Adjustment") is:

Adjusted Beta = 0.35 + (0.67 * Estimated Beta)

This adjustment formula has the impact of increasing the observed Betas for stocks of below-average risk such as the stock of NGDCs. For example, if the unadjusted Beta for an individual stock is 0.50, the Value Line adjustment will produce an adjusted Beta of 0.685.[13] By itself, this adjustment increases Mr. Hanley's CAPM cost of equity by more than 70 basis points. This adjustment therefore has a significant impact on the CAPM cost of equity.

Q. Do the unadjusted Betas for NGDCs suggest that Betas have moved toward unity over time and that the Value Line adjustment is reasonable for NGDCs?

A. No, the unadjusted Betas for the natural gas distribution industry (SIC 4924) prepared by Ibbotson Associates indicate that Betas in this industry declined steadily from 1995 to 2002-2003. While the reported Betas have increased modestly since then, they remain below values in the mid-1990s. Moreover, this pattern is not at all consistent with the expectations in the Blume adjustment.

Q. Do all analysts agree with the Value Line adjustment mechanism?

A. No. While many analysts recommend that adjustments to the estimated Betas be made, various alternatives can be used. Ibbotson Associates indicates that the adjustment mechanism it uses is to recognize that the Beta for an individual stock within an industry tends to move toward the industry average (the "Vasicek Adjustment"). In light of the

[13] The adjusted Beta is 0.35 + 0.67 * 0.50, or 0.685.

observed trend of NGDCs' Betas moving away from unity, the latter adjustment approach appears to be superior for this industry.

Q. In the end, how do you develop a Beta for your analysis?

A. I considered four methods for calculating Betas: (a) a simple average of the Value Line adjusted Betas presented by Mr. Hanley (although I did not exclude the one that he rejects); (b) a simple average of the Value Line unadjusted Betas; (c) the Betas reported by Quote.com and Yahoo Finance data sources that are readily available to investors, and (d) the 2006 Beta estimate for SIC 4924 by Ibbotson Associates.[14] A simple average of these three sources implies a Beta of 0.58.

Q. Mr. Hanley's CAPM analysis includes an Empirical Capital Asset Pricing Model ("ECAPM") calculation. Did you include ECAPM calculations?

A. Yes. Although the ECAPM has no sound theoretical justification, and the specific model used by Mr. Hanley has limited empirical support, I have included this approach. The ECAPM attempts to address one of the major criticisms of the CAPM, namely that the actual premiums in stock returns associated with increasing risk (as measured by Beta) are less than those implied by the CAPM. The ECAPM therefore implies higher returns for low-risk stocks (like regulated utilities) and lower returns for higher-risk stocks.

2.2.4 CAPM and RP Summary

Q. Can you summarize the differences between your CAPM and RP analyses with those presented by Mr. Hanley?

A. Table IEc-2 below provides a comparison of the basic assumptions used in our respective analyses:

[14] For the Ibbotson estimate, the current value is similar to the 10-year average value.

Table IEc-2 Comparison of CAPM and Risk Premium Approaches Factors Considered		
	IEc	*Hanley*
Current L-T Risk-Free Rate	Current Treasury Bond Yields	Not Considered
Future L-T Risk-Free Rate	Yield Curve	Blue Chip Financial Forecasts
Current S-T Risk-Free Rate	3-Month T-Bill	Not Considered
Future S-T Risk-Free Rate	Current 3-Month T-Bill and Yield Curve	Not Considered
Corp. and Utility Bond Yields	Historical Premiums over T-Bonds	Blue Chip Financial Forecasts
Beta	Value Line Adjusted Betas Value Line Unadjusted Betas Quote.com Betas Ibbotson Associates Beta for SIC 4924	Value Line Adjusted Betas
Market Risk Premium	L-T Historical Premium Mercer Forecast Premium	L-T Historical Premium Value Line Implicit Forecast
Utility Risk Premium	L-T Historical Premium Adj. L-T Historical Premium	L-T Historical Premium
Empirical CAPM	Yes	Yes

Q. Of the differences that you report in Table IEc-2 above, which have the most significant effect on equity cost calculations?

A. The major differences between Mr. Hanley's analysis and mine are (a) I use a number of different approaches to derive Beta, and these sources imply that NGDCs are lower risk than the Beta determined by Value Line, and (b) I use Mercer's expected returns on equities as a measure of future market returns, whereas Mr. Hanley relies on Value Line, or, as in the case of his utility risk-premium analysis, none at all.

Q. Can you summarize the impacts of your adjustments to Mr. Hanley's analysis for the RP and CAPM methods for the cost of NGDC equity?

A. Table IEc-3 below summarizes the differences in the implied equity cost of capital resulting from the various methodologies. The key differences between my analysis and that of Mr. Hanley are the use of updated, lower interest rates; the inclusion of unadjusted

and alternative adjusted Betas; and the use of NFGD's actuarial assumptions for expected market returns.

Table IEc-3 Comparison of Equity Cost of Capital Risk Premium and CAPM Methodologies		
	IEc	*AUS/NFGD*
Beta-Adjusted Market RP	8.7%	10.8%
Utility Risk Premium	9.0%	10.6%
Long-Term CAPM	8.3%	10.4%
Long-Term ECAPM	9.0%	10.4%
Short-Term CAPM	8.8%	N/A
Short-Term ECAPM	9.5%	N/A
Simple Average	**8.9%**	**10.6%**

2.3 Discounted Cash Flow Analysis

Q. Can you summarize Mr. Hanley's DCF analysis?

A. Mr. Hanley applies the standard DCF cost of equity model, in the form:

DCF Cost of Equity = Dividend Yield + Growth Rate

DCF Cost of Equity = $D_1 / P_0 + g$

Because NFGD's parent corporation, National Fuel Gas ("NFG"), is not a pure NGDC, and to avoid other problems with applying the DCF model to a single firm, Mr. Hanley performs his DCF analysis on two proxy groups of NGDCs. The first group contains four NGDCs, and the second group contains nine NGDCs, including the four in the first group. Mr. Hanley's standards for whether the companies are NGDCs are slightly relaxed for the second sample. Mr. Hanley then computes the average dividend yield for each company over the period February to April 2006, and adjusts that dividend yield for one-half the expected growth rate, consistent with the Gordon model. (This adjustment is necessary to meet the requirements of the model, in which the dividend yield is computed as the dividend in the first period divided by the stock price in the base period.)

To develop estimates for the rate of growth, Mr. Hanley averages the 3-year earnings-per-share growth forecast from Value Line with the 5-year forecast from ThomsonFN/First Call for each company in the sample.

Without any further adjustment, this approach would produce a DCF return of 9.7 percent for the four-firm sample and a 9.4 percent return for the nine-firm sample. Thus, Mr. Hanley's unadjusted DCF analysis implies a cost of common equity that is substantially below NFGD's proposal.

However, for developing his recommended cost of equity, Mr. Hanley makes two other adjustments. First, he makes an adjustment for financial leverage, to recognize that NFGD has different financial leverage on a market basis than on a book basis. Second, as what appears to be a check on the average of all four methodologies, Mr. Hanley computes a "practical" adjusted DCF calculation. This calculation excludes those sample companies whose implied DCF return falls below 9.45 percent. This criterion eliminates two of the four companies in the smaller sample, and five of the nine companies in the larger sample. In the end, Mr. Hanley's DCF analysis is based on four sample firms.

Q. Is it appropriate for Mr. Hanley to eliminate most of the NGDCs in his sample in developing the DCF cost of equity estimates?

A. No. Mr. Hanley excludes the implied cost of equity from any firm that is lower than the lowest recent allowed return on equity, namely 9.45 percent. As I noted in my testimony in NFGD's last base rates case, Mr. Hanley's sample companies are like the children in Lake Wobegone -- they are all above average.[15] Mr. Hanley simply eliminates the data related to firms that exhibit below-average DCF returns.

It is unreasonable to exclude below-average observations. The regulatory commissions that approve relatively low rates of return on the order of 9.45 percent presumably considered a sample of utilities whose cost of capital included observations both above and below that 9.45 percent. By arbitrarily excluding all observations below 9.45

[15] With apologies to Garrison Keillor, "A Prairie Home Companion." Also, it must be noted that Mr. Hanley is not directly relying on this practical DCF calculation for recommending a cost of equity, as he did in the last case.

percent, it is impossible for Mr. Hanley's analysis to produce a recommended return on equity of 9.45 percent, even though a regulatory authority has approved that rate of return. Further, by excluding the observations that are below the lowest actual allowed rate, Mr. Hanley's approach will not recognize the declining trend in allowed returns on equity discussed above.[16]

Q. Is it reasonable for Mr. Hanley to rely only on earnings estimates from Value Line and First Call in developing DCF growth rates?

A. No. Many analysts include historical growth trends and sustainable growth trends in preparing DCF analyses.[17]

Q. How have you modified the analysis to correct these issues?

A. For the purpose of this analysis, I have adopted Mr. Hanley's two sample sets, but I have not excluded any observations. In developing growth rates, I used the two earnings forecasts presented by Mr. Hanley, but also added ten-year historical average growth rates in book value per share, earnings per share, and dividends per share. I use the historical averages because it is likely that investors consider both actual historical performance and analysts' forecasts, particularly in light of the historical bias in analysts' forecasts. I include both cash flow and dividend growth rate measures as well, because these are more consistent with the DCF theoretical model. A summary of the impacts for unadjusted DCF analysis is shown in Table IEc-4 below. I note that the DCF range from this analysis, which implies a DCF cost of equity of 8.5 to 8.6 percent, is a little higher than the Ibbotson Associates' 2006 DCF estimate of 8.1 percent for NGDCs.

[16] Note that, even after having excluded all below-average observations, Mr. Hanley recommends adding a market-to-book adjustment factor. Even if it were reasonable to exclude observations for the reasons Mr. Hanley suggests, he should exclude only those observations whose *adjusted*-DCF values, rather than unadjusted DCF values, fall below the 9.45 percent.

[17] Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, page 319.

Table IEc-4 Comparison of DCF Analyses				
	NFGD Analysis		*IEc Analysis*	
	2-Firm Sample	*4-Firm Sample*	*4-Firm Sample*	*9-Firm Sample*
Adj. Dividend Yield	***4.59%***	***4.62%***	***4.48%***	***4.57%***
Growth Rates				
Value Line F'cast Earnings	7.75%	7.38%	6.38%	5.17%
First Call F'cast Earnings	4.50%	4.95%	4.05%	4.53%
10-Year Actual Earnings	NA	NA	2.38%	3.33%
10-Year Actual Dividends	NA	NA	2.63%	2.28%
10-Year Actual Net Book	NA	NA	3.50%	383%
Average Growth Rate	***6.13%***	***6.16%***	***4.02%***	***4.00%***
DCF Equity Cost	**10.72%**	**10.78%**	**8.50%**	**8.57%**

Note also that the few companies that Mr. Hanley includes in his analysis exhibit a very wide discrepancy in growth rates between the Value Line and First Call earnings forecasters. This differential is one of the serious problems associated with using so small a sample and then relying only on earnings forecasts. By way of contrast, the average forecast earnings from the larger sample are at least somewhat closer together, and they are also reasonably consistent with the historical average actual growth rates.

Q. Can you comment on the adjustment mechanism used by Mr. Hanley to account for market-to-book equity price premiums?

A. I do not agree that a market-to-book adjustment mechanism is theoretically sound, for DCF analyses or for other equity cost methods. In the theoretical world, if equity returns exactly match the cost of equity capital, utility market-to-book ratios would be unity. While there are many factors that can lead to utility market-to-book ratios being in excess of unity, a significant factor is the expectation for allowed returns. Increasing allowed returns when market-to-book ratios are high leads to circularity problems. Higher returns will increase market prices, which increase the market to book ratios, which then lead to larger adjustment factors. Since my analysis indicates that regulatory commissions have

been awarding equity returns that are generally higher than the cost of equity capital, it is likely that the allowed returns have already contributed significantly to the high market-to-book ratios. The proposed adjustment factor will only make the problem worse.

Having said that, I recognize that the Commission has allowed similar adjustments in the past. Therefore, in developing my recommendation for the allowed return in this matter, I have qualitatively considered the implications of Mr. Hanley's adjustment calculations.

2.4 Deemed Capital Structure

Q. Turning to Mr. Hanley's proposal for a deemed capital structure for NFGD, does Mr. Hanley adopt the average capital structure of his sample group of utilities?

A. No. Mr. Hanley argues for a heavier weighting toward equity because of the higher risk of both NFGD and its parent NFG as perceived by the rating agencies, notably Standard & Poors ("S&P"). S&P assigns NFG a business risk factor of 7, while the proxy groups of NGDCs exhibit average ratings of 1.8 to 2.3. Mr. Hanley concludes, based on his review of the S&P report, that as a stand-alone distribution company, NFGD's business risk rating would be no better than a 4. He uses that rating to recommend a capital structure with 51.5 percent equity.

However, my review of the S&P report suggests that the vast majority of the higher risk for NFG as perceived by the rating agencies is related to its unregulated activities and its high debt burden, which S&P reports at 60 percent of capital. The only reference in the S&P report cited by Mr. Hanley in support of his conclusion that NFGD is riskier than his sample of NGDCs is that NFGD faces "a sluggish local economy that provides minimal growth opportunities, [and] a service territory that is somewhat saturated with natural gas." Mr. Hanley also cites S&P's favorable reference to the weather normalization clause in NFG's New York service territory as an indication that the lack of a weather normalization clause in Pennsylvania is a risk factor.

A business profile rating of 4 would put NFGD in the bottom 22 percent of S&P's rated transmission and distribution utilities. S&P considers regulated distribution utilities, on average, to be much less risky than utility and power companies generally.

Q. What do you propose for NFGD's deemed capital structure?

A. I believe that an average of the actual capital structure from Mr. Hanley's sample of firms is reasonable for two reasons. First, there is very limited evidence that NFGD's Pennsylvania gas distribution business is any more risky than the sample of NGDCs that are used to derive cost of equity estimates. Second, if NFGD is assumed to have a less leveraged capital structure than the sample utilities, the cost of equity estimates from that sample should be adjusted downward for the reduced leverage. Rather than go through the convoluted process of adjusting all of the sample firms' equity costs for a different level of leverage, I simply use an average capital structure from the set of sample firms to be consistent with the cost of equity derived from those sample firms.

To avoid short-term effects, I use an average of the most recent capital structure with the average of the past five years. Table IEc-5 below compares the capital structure that I propose with that adopted by Mr. Hanley.

Table IEc-5
Deemed Capital Structure Comparison

	NFGD Proposed	*Recent 5-Quarter Average*	*5-Year Sample Average*	*IEc Recom-mendation*
Short-Term Debt	8.46%	9.27%	12.64%	10.83%
Long-Term Debt	40.04%	42.92%	41.76%	42.20%
Total Debt	48.50%	52.19%	54.40%	53.03%
Common Equity	51.50%	47.81%	45.60%	46.97%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Note: The sample average represents a simple average of Mr. Hanley's 4-firm sample and Mr. Hanley's 9-firm sample.

2.5 Other Adjustments

Q. What other adjustments does Mr. Hanley propose in his return on equity recommendation?

A. Mr. Hanley proposes that the equity return calculated using the various equity cost methods be incremented by 30 to 60 basis points to reflect the relatively small size of NFGD relative to the sample firms. He also proposes an adder of 13 to 17 basis points to reflect the absence of a weather normalization adjustment at NFGD in Pennsylvania.

Note that Mr. Hanley's calculations indicate that he believes a size premium of 188 basis points is justified, but he uses a 30 to 60 basis point premium to be conservative.

Q. Do you agree with Mr. Hanley's proposal for a size adjustment for NFGD's return on equity?

A. Generally, I do not. I do agree with Mr. Hanley that there is substantial evidence that smaller firms averaged across all industries have historically exhibited higher rates of return, adjusted for systematic risk, than larger firms. However, one obvious reason for this superior performance is that these smaller firms have greater growth potential than larger firms. As evidenced by Mr. Meinl's testimony and the S&P report referenced earlier, this greater growth potential does not apply to NFGD.

In addition, the smaller firms that exhibit the higher-than-modeled returns also have above-average systematic risk characteristics. In developing his calculated premiums, Mr. Hanley relies on an analysis performed by Ibbotson Associates that shows that the returns for small firms lie above the CAPM security market line. (See Exhibit 400, Schedule 1, page 24.) However, that analysis also shows that, as average firm size gets smaller, the systematic risk increases. In that analysis, firms of NFGD's size (as determined by Mr. Hanley) have Betas of 1.34 to 1.43. These firms are not comparable to NGDCs, for whom Ibbotson Associates estimates a median industry Beta of 0.25.

If evidence were presented demonstrating that the historical market returns for small firms that exhibit both limited growth potential and well below average risk, as NFGD does, a size factor adjustment might be appropriate. However, it is not reasonable to add a size premium to NFGD based on the historical excess returns of high-risk, high-growth firms.

Finally, I note that NFGD's size is a management decision. If NFGD can reduce its cost of equity capital (and possibly operating costs as well) by merging with other NGDCs, perhaps it should do so. It is not clear that NFGD should be rewarded with an equity return adder because NFGD chooses to remain a small gas distribution company.

Q. Do you agree with NFGD's proposed adder for the absence of a weather normalization adjustment in Pennsylvania?

A. No, as NFGD has not proposed a weather normalization adjustment in this proceeding, nor did it in either of its last two base rates cases.[18] As such, a risk premium for the lack of such an adjustment is not appropriate.

2.6 Summary of Rate of Return

Q. In light of both the top-down and bottom-up analyses, what do you recommend for NFGD's rate of return in this proceeding?

A. First, I recommend that the Commission approve a return on equity in the range of 9.75 to 10.25 percent. In preparing this recommendation, I have considered the results of my detailed analyses, the issue of consistency with actuarial assumptions, the allowed returns from other regulatory jurisdictions as well as this Commission's PPL decision discussed below, and the DCF adjustment factor that Mr. Hanley recommends. In general, the detailed DCF, CAPM and RP analyses indicate that the cost of equity capital for a typical NGDC should be at or below 9.0 percent. Furthermore, the market assumptions used by NFGD's actuaries also suggest that a risk-adjusted return on equity for typical NGDCs should be below 9.0 percent.

Nevertheless, the recent decisions by regulatory commissions across the country for NGDCs and EDCs, combined with this Commission's decision in PPL, suggests that investors currently expect returns substantially in excess of 9.0 percent. Therefore, setting the return on equity substantially below that approved for other utilities would potentially result in a significant drop in the common stock price for the affected utility, and would conflict with the normal regulatory practice of gradual change. Thus, I recommend that the Commission make a modest step in the direction of moving allowed equity returns into line with the analytical cost of equity by setting the allowed return in this case in the 9.75 to 10.25 percent range. In so doing, the Commission will implicitly recognize the market to book adjustment recommended by Mr. Hanley, because it will be cognizant of the potential market impact on NFG's shareholders that would result from strict application of the DCF analysis.

[18] As I will explain below, and as I believe NFGD recognizes, its proposed revenue decoupling mechanism is not really a weather normalization adjustment because it lacks the bill stabilization benefits of other WNAs.

Second, I recommend that the deemed capital structure that arises from an average of the NGDCs selected by Mr. Hanley be adopted. With that capital structure and NFGD's proposed debt costs, I recommend an average return on rate base of 7.8 to 8.0 percent. I estimate that this rate of return reduces NFGD's proposed rate increase by $5.4 million to $6.6 million.

Q. Your proposed range 9.75 of 10.25 percent is below the 10.7 percent approved by the Commission for PPL in 2004. Can you explain why a lower rate is appropriate for NFGD?

A. At the outset, let me acknowledge that there are many reasons why the allowed return on equity for PPL would be expected to be different from the cost of equity for NFGD. As a theoretical matter, it is probably inappropriate even to make the comparison, in light of all of the differences. Nevertheless, from a practical perspective, that decision will likely have a precedential impact on any fully litigated rate case.

Also, for the record, the equity share of total capital approved by the Commission in PPL was 46.6 percent, a value much closer to my recommendation in this proceeding than NFGD's.

In the PPL decision, the Commission also indicated that, in reaching its determination, it would rely primarily on the DCF methodology, but would also "use the results of the CAPM and RP methods as a check of the reasonableness of our DCF calculations." Note that, while PPL did submit equity cost estimates based on the "Comparable Earnings" approach, the Commission appears to have not relied on them in reaching its decision.

In reaching its decision, the Commission relied on the unadjusted DCF analysis of EDCs, which implied a cost of equity of 10.25 percent. However, the Commission increased that value to 10.70 percent, based on consideration of PPL's high market to book ratio, with due consideration of the CAPM and RP results.

In this matter, Mr. Hanley's unadjusted DCF analysis indicates that the DCF cost of equity is 9.4 to 9.7 percent, if NGDCs are not arbitrarily excluded from his sample, while my DCF analysis suggests a cost of equity capital of 8.5 to 8.6 percent. Moreover, the Ibbotson Associates' independent DCF analysis for the natural gas industry indicates a median DCF return of 8.1 percent for 2005. Even applying the Commission's 45 basis

point increase for Mr. Hanley's unadjusted DCF estimates will produce equity returns that are lower than my upper bound recommendation of 10.25 percent.

3. Test Year Throughput Forecast

Q. Please provide an overview comparison of NFGD's proposed throughput forecasts between its last two base rates cases and the present filing.

A. Exhibit IEc-3 presents a comparison of the number of customers, the throughput, and the throughput per customer for each rate class in each of NFGD's last three base rates proceedings (including the current one). Those proceedings involved test year volume forecasts for the test year ending September 2003, May 2005, and January 2007. Note that all test year volume forecasts are based on normal weather conditions. Thus, the differences between these forecasts are generally based on non-weather factors.

That exhibit shows that NFGD's forecast for usage per customer for residential and small commercial customers was not very different between the 2003 and 2005 test years, whereas the usage per customer drops significantly in the present case. It also shows that the forecast number of residential customers has declined modestly since 2003, while the number of commercial customers has remained relatively flat.

In Exhibit IEc-3, I also provide a rough estimate of the lost revenue associated with the reduction in usage per customer between the 2005 test year and the current filing. Had the usage per customer remained constant since the 2005 case, I estimate that NFGD's test year revenues in this proceeding would be at least $4.3 million higher.[19]

Q. Is there any aspect of the values in Exhibit IEc-3 that causes you some particular concern?

A. Yes. NFGD forecasts a use per customer reduction of some 7.8 percent for residential customers, and of some 5.2 percent for the three commercial/public authority classes combined. While these are fairly large reductions, the effects among the various different commercial/public authority classes are more surprising. In particular, NFGD is forecasting that use per customer for the smallest commercial customers, in the SC&PA

[19] Because I assume that the entire reduction in use per customer would have been priced at tail block rates, this value is a minimum.

LE250 class, will be more than 15 percent lower than it was less than two years ago. A change of that magnitude deserves some explanation.

Q. Please provide your general understanding of how NFGD develops its forecasts of usage per customer for each customer class.

A. NFGD prepares econometric analysis of per-customer throughput for three separate customer groups: residential, commercial, and public authority. That econometric analysis estimates a statistical relationship between NFGD's historical per-customer use and several explanatory variables. In NFGD's formulation, those explanatory variables include heating degree days, inflation-adjusted prices paid for gas, and a trend variable designed to reflect non-price-related efficiencies and conservation. The statistical relationship is estimated based on actual monthly per-customer throughput volumes and the other variables from February 1991 to December 2005, for each of the three groups.

NFGD then forecasts usage per customer for the test year using its econometric equations, for the residential, commercial and public authority customer groups.

Finally, NFGD translates its commercial and public authority volume forecasts into rate class volume forecasts, using a procedure that I do not currently understand.

Q. Before we get to the issue you do not understand, please explain the basis for NFGD's forecast of declining usage per customer for the three major groups of customers from its econometric forecast.

A. NFGD's econometric analysis indicates that all three rate classes exhibit the effect that we all learned in Economics 101, namely that as price rises, demand falls. In addition, in NFGD's analysis of both residential and commercial customer groups, usage per customer is declining over time, for reasons other than the estimated effect of rising prices.

For the residential class, the decline in usage per customer is related significantly to both the trend effect and the price effect. The residential trend effect is a decline of approximately 1.8 percent per year, which means that about half the decline in usage per customer since the May 2005 test year is related to this factor. The price effect represents the balance of the change.

When evaluating the price effect, economists often think in terms of a "price elasticity of demand." This elasticity represents the percentage change in demand that results from a particular percentage change in price. For example, if a 10 percent increase in price results in a 3 percent reduction in demand, the price elasticity of demand is -0.3. Based on NFGD's residential equation, I estimate that the residential price elasticity of demand is about -0.14.[20] From a practical standpoint, this is actually a relatively low value, more consistent with a short-run price effect than a long-run price effect. Therefore, the reduction in NFGD's usage forecast is not a result of a particularly high elasticity value -- it is a result of a large increase in price.

To understand the price impact, it is necessary to recognize that, in its analyses, NFGD uses a price variable that is lagged ten months. This means, for example, that the consumption for the period January to December 2005 is estimated as a function of gas prices between March 2004 and February 2005. Thus, when NFGD turns to forecast consumption for the test year ending January 2007, it will rely on the average gas price paid by ratepayers between April 2005 and March 2006. And, yes, that means the test year forecast in this case is significantly affected by the large increase in gas prices in the fall of 2005, exacerbated by Hurricane Katrina.

NFGD's econometric analysis of its commercial customers shows a similar pattern, although the trend variable is lower (a 0.6 percent per year decline) and the price elasticity effect is a little higher (-0.19). For the public authority class, the price elasticity of demand is -0.18, and there is no trend effect.

Q. You mentioned earlier that you do not understand how NFGD takes its commercial and public authority forecasts and translates them into throughput volumes for the SC&PA and LC&PA classes. Can you elaborate?

A. OSBA-29 requested that NFGD explain how the forecasts by customer group were translated into specific rate class forecasts. While NFGD's response shows that this allocation was done, it provides few hints as to the methodology that was employed.

[20] NFGD's econometric equations are estimated in a linear rather than a constant elasticity specification. Thus, the elasticity implied by the equation will vary depending on the particular volumes and prices at which it is evaluated. For the purposes of elasticities reported in this testimony, I have used values as of January 2006.

Moreover, it does not provide any explanation of why the usage per customer for the SC&PA LE250 customers is so much lower than it was in the last base rates case.

The OSBA has therefore submitted additional interrogatories in an effort to shed light on this anomaly. If my analysis of those responses indicates that NFGD's method is flawed, I will update this testimony promptly.

Q. What would the implications be if NFGD has improperly allocated the volumes among the commercial customer classes, such that the SC&PA LE250 customers' volumes were understated?

A. If that were the case, NFGD's COSSs would overstate the cost of providing service to the SC&PA LE250 customer and understate the cost of providing service to other commercial customers. Depending on the magnitude of the impact, it may be necessary to modify my revenue allocation recommendations in this proceeding.

4. Cost Allocation

Q. *Please describe the key features of NFGD's approach in this proceeding with respect to preparing a COSS.*

A. NFGD filed COSSs that employ four different methodologies, each at present and proposed rates. This approach produces eight COSSs, presented in NFGD's Exhibits 111-A through 111-H. The methodological differences among the studies relate only to the classification and the allocation of distribution mains costs, with two alternatives for each. For mains cost *classification*, NFGD presents studies that assume that all mains costs are 100 percent demand-related, as well as studies that assume that mains costs are classified into both customer and demand components using a "zero-intercept" methodology. For mains cost *allocation*, NFGD presents studies that allocate the mains demand-related costs using a "peak and average" ("P&A") allocator, and studies that allocate those costs using a design day peak demand allocator. The various NFGD studies are summarized in Table IEc-6 below:

Table IEc-6 NFGD Cost of Service Study Methodologies		
	100 % Demand Mains Classification	*Zero-Intercept Mains Classification*
Peak & Average Allocator	A: Present Rates B: Proposed Rates	C: Present Rates D: Proposed Rates
Design Day Peak Allocator	E: Present Rates F: Proposed Rates	G: Present Rates H: Proposed Rates

Q. Did you replicate NFGD's COSSs as filed?

A. Yes. As part of my replication analysis, I identified minor errors in NFGD's results, but these do not have a material impact on the results.[21]

Q. Do you agree with NFGD's methodological approach?

A. Individually, all of NFGD's studies contain economic or analytical flaws. In particular:

- Natural gas distribution systems exhibit economies of scale, meaning that many small customers are more expensive to serve than are a few larger customers with the same peak demand. Moreover, distribution mains must be installed with sufficient capacity to meet peak demand, and with sufficient length to interconnect all of the customers. Classifying mains costs into both demand and customer components properly recognizes these cost causation factors. Thus, the NFGD studies that have no customer component (A, B, E, and F) are not consistent with cost causation.

- Natural gas distribution mains are sized to meet the peak demand served by those mains. The size of the main is in no way related to the average throughput. If mains were sized to meet "peak and average" demand, the distribution system would not be capable of meeting customers' needs on a cold winter day. Thus, the NFGD studies that rely on the P&A allocator (A, B, C, and D) are not consistent with cost causation.

[21] The errors that I identified are in the versions of NFGD's COSS that contain the zero-intercept classification of mains costs, namely versions C, D, G, and H. In those studies, NFGD incorrectly excludes the mains customer-related costs from its mains/services allocator (allocation factor #32). For the purposes of this testimony, I corrected this error, to be consistent with the approach that NFGD used in the past.

- NFGD's zero-intercept analysis that classifies mains costs into demand and customer components contains a number of methodological flaws that likely result in an overestimate of the customer component of costs. Therefore, the NFGD studies that use the zero-intercept classification approach (C, D, G, and H) likely overstate the customer component of costs that would result from an accurate classification analysis.

Q. Can you elaborate on your concerns regarding NFGD's zero-intercept analysis?

A. Due to budget constraints and based on consultation with OSBA counsel, I have not performed a detailed review of NFGD's zero-intercept analysis. However, in NFGD's base rates case in 2003 (R-00038168, as presented in my direct testimony dated July 25, 2003), I conducted a thorough evaluation. Based on that analysis, combined with my review in this case, I conclude that NFGD's approach is flawed because it:

- Did not adjust plant cost data for inflation;
- Relied solely on a quadratic formulation for the regression analysis;
- Does not differentiate mains pipe by material (plastic, steel, cast iron, etc.), which is standard practice;
- Improperly assigned large weights to relatively insignificant data observations in the statistical analysis;
- Included very large diameter pipe in the analysis that likely has no customer component; and
- Failed to weight recent information more heavily than older data (which included mains plant installed over 100 years ago).

In my analysis in 2003, correcting for the errors led me to conclude that NFGD's customer component of 41 percent was excessive, and that a 25 percent customer component was consistent with reasonable analysis. Moreover, based on my experience with zero-intercept analyses at other NGDCs, NFGD's estimate of 52.6 percent is relatively high.

Thus, NFGD's proposed customer component of 52.6 percent in this proceeding is likely to be too high. In effect, the customer component of costs in studies A, B, E, and F is unreasonably low (zero), while the customer component of costs in studies C, D, G, and H is overstated.

Q. Do you have any concerns about NFGD's cost allocation studies that imply that costs may be over-assigned to small business customers?

A. NFGD's COSSs appear to assign excessive costs to small business customers in a couple of areas. These include:

- NFGD's COSS does not recognize the higher working capital costs imposed by residential customers than business customers. A utility's revenue lag from residential customers is generally considerably higher than it is from business customers, which causes higher working capital costs.
- While NFGD's COSS assigns all direct customer assistance program costs to the residential class, consistent with cost causation principles, it appears to assign the administrative costs to all classes. As the administrative costs are incurred only for residential customers, they should be allocated accordingly.

Q. In the end, what COSS methodology did you rely upon for developing your class revenue requirement proposal in this proceeding?

A. In general, correcting the major methodological errors that I identify above would have the tendency to produce COSS results that lie within the range of the four studies presented by NFGD. Moreover, it is unlikely that correcting the biases against small business customers that I identify would have a material effect on the implications from these COSSs. Therefore, for the purposes of this proceeding, I use a simple average of the four NFGD studies, with the proviso that I have corrected the programming error that I mentioned earlier.

Note, however, if NFGD's use per customer forecast for the SC&PA LE250 customers proves to be materially in error, the COSS analysis may need to be modified.

Q. What are the results of that analysis?

A. Table IEc-7 below shows the class rates of return and class revenue-cost ratios under present rates for each rate class, using an average of the four methodologies.

Table IEc-7
Average NFGD Cost of Service Study Results
Present Rates

Rate Class	*Class Rate of Return*	*Normalized Class Revenue-Cost Ratio*
Residential	2.63%	91.9%
SC&PA LE 250	6.14%	107.0%
SC&PA GT 250	10.96%	135.8%
LC&PA	11.52%	135.4%
SVIS	19.32%	160.8%
IVIS	12.11%	132.8%
LVIS	11.91%	122.5%
LIS	7.43%	110.6%
Total	***4.48%***	***100.0%***

Overall, Table IEc-7 demonstrates that under present rates, the residential class is substantially subsidized by the other rate classes, all of which contribute to the subsidy. Further, the table indicates that the SVIS class is providing the largest subsidy in percentage terms, and that the subsidy provided by the SC&PA GT250 and LC&PA rate classes is as large or larger than that provided by the large industrial classes (IVIS, LVIS, and LIS).

Moreover, as detailed in Table IEc-8 below, the residential class is subsidized in all four of the COSS methodologies, and *all* of the non-residential classes contribute to that subsidy in almost every case. Thus, despite the significant methodological differences in the studies, the basic cost signals remain the same.

Table IEc-8 NFGD Cost of Service Study Results Class Rates of Return				
	A: 100% Demand; P&A	*C: Z-I Customer; P&A*	*E: 100% Demand; Peak*	*G: Z-I Customer; Peak*
Residential	3.4%	2.2%	3.0%	2.0%
SC&PA LE 250	7.0%	5.8%	6.4%	5.4%
SC&PA GT 250	9.4%	13.5%	8.4%	12.5%
LC&PA	7.8%	15.6%	7.5%	15.1%
SVIS	16.2%	19.2%	20.0%	21.8%
IVIS	6.2%	14.9%	8.8%	18.6%
LVIS	2.7%	11.4%	9.8%	23.7%
LIS	4.8%	5.1%	9.9%	9.9%
Total	***4.5%***	***4.5%***	***4.5%***	***4.5%***
Note: Rate classes exhibiting rates of return below system average, i.e., subsidized rate classes, are shaded in this table.				

Q. What are the implications of NFGD's COSS results?

A. From a cost of service perspective, the residential rate class' revenues currently under-recover allocated costs, while the rest of the rate classes provide that subsidy.[22]

5. Revenue Allocation

Q. What are the key rate design principles that most utilities use for allocating the revenue increase among the rate classes?

A. The process generally begins with the revenues produced under existing rates from each class. These revenues are included in the COSS analysis at present rates. The "present rates" study shows each class' over- or under-recovery of allocated costs at the existing rates. The relative over- or under-recovery of costs is evaluated using a variety of different metrics that depict the relationship between revenues and allocated costs. Most utilities and regulators adopt a policy in a base rates proceeding of attempting to move

[22] Note that I use the term subsidy as it is commonly used in regulatory proceedings involving embedded cost of service studies, namely as the difference between allocated costs and class revenues. The theoretical economics definition of a subsidy is different.

revenues more in line with allocated costs by varying the magnitude of the rate increases for the various classes, but they also subject the rate increases to other non-cost criteria of ratemaking. Of the traditional rate design criteria, the most common non-cost considerations in the revenue assignment process are:

- the gradualism principle (or avoidance of "rate shock"), in which large rate increases for individual customers or classes of customer are avoided; and
- the value of service principle, which is often used to mitigate rate increases for customers or customer classes with relatively elastic demand.

Using these criteria, the utility will develop a proposal for assigning the increase in the revenue requirement among the classes that reflects both cost and non-cost considerations. With this proposal, the COSSs are then re-simulated to show the impact on cost recovery at "proposed rates." With the two sets of COSSs, at existing and proposed rates, the utility can evaluate whether any "progress" has been made toward the policy of achieving cost-based rates. The results of this analysis of progress study may then be used to develop a revised revenue allocation proposal, and an iterative process follows until the rate designer is satisfied.

Q. What is NFGD's proposal for assigning the revenue increase among the rate classes in this proceeding?

A. In this proceeding, NFGD is proposing to change both distribution rates and gas sales rates, both of which have impacts on class revenue increases. For the purpose of this section of my testimony, I address NFGD's proposals for distribution revenue allocation, as reported in Exhibit 103 Schedule 1A. Because NFGD simulated its COSSs using all of its proposed rate changes, its COSS results are slightly different than mine.[23] However, the primary focus of NFGD's COSSs is on base rates costs, and the allocation of purchased gas costs in its COSSs is not consistent with its proposed changes in the

[23] It appears that NFGD's treatment of revenues and gas costs in its COSSs is not consistent. The proposed revenues reported on page 4 of the proposed-rates COSSs (B, D, F, and G) are based on NFGD's proposed rates from Exhibit 103 Schedule 1; i.e., including the proposed seasonalization of the demand-related portion of PGC cost recovery. However, the gas costs reported on page 6 of the COSSs are based on the purchased gas revenues from Exhibit 103 Schedule 1A; i.e., non-seasonalized PGC rates. The implications of this apparent inconsistency are relatively small, however.

purchased gas cost rates. Therefore, to compare apples to apples, I compare the proposed increases exclusive of PGC effects to the results of NFGD's COSS analyses.

With that caveat, NFGD's proposal is summarized in Table IEc-9 below. In that table, I report the average revenue-cost ratio for each class that comes from averaging the four NFGD COSS methodologies, all at present rates. I also show the proposed percentage rate increase and the dollar value of the increase proposed by NFGD to achieve its claimed increase of $25.8 million.

Table IEc-9
NFGD Proposed Distribution Rate Increases

	Avg. Class Rate of Return Present Rates	*NFGD Proposed Percentage Increase*	*NFGD Prop. Distribution Rate Increase $mm*	*Avg. Class Rate of Return Prop. Rates*
Residential	2.63%	27.0%	20.236	7.94%
SC&PA LE 250	6.14%	27.1%	1.145	12.30%
SC&PA GT 250	10.96%	26.9%	1.330	16.56%
LC&PA	11.52%	27.2%	3.180	16.58%
SVIS	19.32%	0.0%	0.000	18.48%
IVIS	12.11%	0.0%	0.000	10.63%
LVIS	11.91%	0.0%	(0.000)	9.07%
LIS	7.43%	0.0%	0.000	7.20%
Total	***4.48%***	***24.5%***	***25.892***	***9.48%***

Note: Distribution increase is both rate revenues and other revenues, based on NFGD proposal in Exhibit 103 Schedule 1-A (excluding seasonalized PGC rates).

As shown in Table IEc-9, NFGD recognizes that its larger industrial customers are currently providing subsidies to the residential class, and it therefore proposes a below-system-average increase (i.e., zero) for those classes. NFGD also at least partly recognizes that the residential class is receiving a subsidy, and it therefore proposes an above-system-average rate increase for that class. However, NFGD proposes to assign an above-system-average rate increase to all of the commercial classes, despite the fact that all of its COSS analyses indicate that these classes are providing subsidies.

NFGD's proposal is therefore hopelessly inconsistent with the principle of recognizing costs in its revenue allocation, as far as its commercial customers are concerned.

Q. Do you have an alternative proposal for assigning the revenue requirement among the various rate classes?

A. Yes I do. From Table IEc-9 above, it is apparent that NFGD should assign a larger rate increase to residential customers and a smaller increase to commercial customers. It also suggests that a rate increase should be applied to the LVIS and LIS rate classes, for whom NFGD proposes zero rate increases.

However, if NFGD's total proposed increase of $25.9 million is approved, a proposal for a larger increase would involve assigning a larger rate increase to residential customers than that originally proposed, and therefore a larger rate increase than the one for which customers already received notification. In addition, NFGD has indicated that it cannot apply rate increases to its large industrial customers without the significant risk of load loss.

I have therefore developed a proposal for first dollar relief ("FDR") for commercial customers, in the event that NFGD's proposed rate increase is reduced by the Commission. As I will demonstrate, if the eventual approved rate increase is materially below the increase proposed by NFGD (as it was in NFGD's last two base rates cases), my proposal will result in reasonable progress toward cost-based rates for all rate classes, relative to NFGD's proposal.

Q. What is first dollar relief ("FDR")?

A. First dollar relief is a revenue allocation approach that is designed to provide relief to rate classes whose revenues, under utility-proposed rates, are higher than their allocated costs. If (and when) the Commission reduces the overall revenue requirement that was proposed by a utility, that reduction may be used to specifically offset part of the rate increase that the utility proposed for a particular customer class (or classes). Under FDR, some specific dollar amount of the reduction is first assigned to the rate class (or classes) whose proposed rates exceed allocated costs. The remaining reduction is then allocated among all of the classes.

Q. How did you arrive at your proposal for FDR for the commercial classes?

A. The objective of FDR is to start with the increases as originally proposed by the Company and to reduce the proposed increases to the general service classes until those classes are on a par with the other rate classes in terms of overall cost recovery. In Exhibit IEc-4, I prepared a specific example showing how this mechanism should work. In this example, I assume that the Commission will award a rate increase to NFGD that is $10.0 million below its proposed rate increase of $25.9 million.

Column (1) of that exhibit shows the costs allocated to each rate class, at NFGD's full proposed revenue requirement, based on a simple average of NFGD's four COSSs. These allocated costs include all operating costs, taxes, and returns. NFGD's total revenue requirement (excluding gas costs) as filed is 131.4 million.

The next four columns show the revenues from each class, at present rates (Column (2)), then NFGD's proposed rate increase (Column (3) excluding other revenues and Column (4) including other revenues), and then NFGD's originally proposed revenues (Column(5), being the sum of Columns (2) and (4)). As shown in those columns, NFGD's current rates produce revenues of $105.5 million, and NFGD proposed a $25.9 million increase to $131.4 million.

Column (6) then reports the ratio of revenues to costs for each rate class. As shown, for example, the revenue-cost ratio for LC&PA customers is 132.3 percent, which implies that under NFGD's proposed rate increases, LC&PA customers would pay 132.3 percent of their allocated costs.

Column (7) then shows the cost basis for each rate class at the reduced revenue requirement; i.e., NFGD's proposed $131.4 million less the $10.0 million in costs that are assumed to not be approved in this example. Because the specific nature of all of the cost reductions is not known, this column simply scales back the allocated costs from Column (1) proportionally. That is, I assume that the reductions in NFGD's proposed revenue requirement affect the costs allocated to each class in the NFGD COSS proportionally. This column therefore provides the revised cost basis for each rate class.

Q. Please continue with your example. How do you calculate FDR for commercial customers?

A. To get the commercial rate classes on a par with the average of the rest of the rate classes, I calculate the FDR amount as follows. First, I define the objective of first dollar relief as bringing the commercial classes in line with the average of all of the other non-residential rate classes. In essence, the FDR is designed to bring the subsidy provided by the commercial class into balance with the subsidy provided by the other business classes.

To determine the FDR, I calculate the difference between the revenue-cost ratio for each commercial class and the revenue-cost ratio for the other business classes, which provides a measure of the excess paid by each commercial class in percentage terms. For example, the difference for the LC&PA class is 132.3 percent minus the 99.5 percent value for the industrial classes, yielding a percentage excess of 32.7 percent. I then multiply that difference by the costs allocated to the LC&PA class at the full proposed revenue requirement, which is the $11.253 million shown in the LC&PA row in column (1).

However, in making that calculation for some of the commercial classes, the amount of FDR exceeds the dollar value of the rate increase proposed by NFGD. Therefore, unless the Commission would approve a rate decrease for those classes, it is impossible to fully balance the subsidy provided by some of the commercial classes with the average from the rest of the rate classes. In my experience, the Commission will award a rate decrease to some rate classes while other receive rate increases only in extraordinary circumstances (such as those involving the potential loss of load). I therefore constrain the amount of FDR to be no more than NFGD's proposed increases. Thus, after FDR, the SC&PA GT250 and LC&PA rate classes are assigned a zero increase. For the SC&PA LE250 class, the FDR reduces the subsidy to a level equal to that of the other business classes.

In total, the first $5.04 million in reduction from NFGD's originally proposed system-wide increase of $25.9 million should be used to offset NFGD's proposed increases to the commercial classes. With that relief, the revenue-cost ratio for the SC&PA LE250 class is brought into line with the average of the non-commercial business classes, while the other commercial classes continue to provide above-average subsidies.

Q. Is this $5.04 million figure dependent on how large the reduction is to NFGD's overall proposed increase?

A. No it is not. To get the commercial classes to be on a par with the other business classes for cost recovery, without imposing rate decreases, it is necessary to take that $5.04 million away from NFGD's proposed increases to the commercial classes, even if the reduction in the approved revenue requirement is more than $10.0 million.

Q. Please continue with the example shown in Exhibit IEc-4.

A. Exhibit IEc-4 then shows the allocated cost implications of a reduction in NFGD's proposed increase.

Column (8) then shows the $5.04 million reduction from first dollar rate relief. Column (9) reports the rate increase after first dollar rate relief, and it is simply NFGD's proposed increases less the first dollar rate relief. Column (10) shows the total revenues that NFGD would earn at its proposed rates less the first dollar rate relief. Because the reduction in the revenue requirement ($10.0 million) was greater than the first dollar rate relief ($5.04 million), the total revenues in Column (10) are still greater than costs. Column (11) reports the revenue-cost ratios after first dollar rate relief. As shown in the exhibit, the revenue-cost ratio for the SC&PA LE250 class is exactly equal to the revenue-cost ratio for the average of the non-commercial business classes, at 107.7 percent. Because FDR was constrained, the revenue-cost ratios for SC&PA GT250 and LC&PA are still higher than the average ratio for the non-commercial business classes.

Q. How do you then adjust the rate increases to bring rates in line with allocated cost?

A. The traditional approach in Pennsylvania is to use a proportional scaleback of the remaining proposed increases. This scaleback is shown in Exhibit IEc-4 in column (12).

The proportional scaleback calculation works as follows. The overall allowed increase in this example is $15.89 million (NFGD's proposal of 25.89 less the $10.0 million reduction assumed in this example). After FDR, NFGD's increase is the originally proposed $25.89 million less the $5.04 million in FDR or $20.85 million. This leaves $4.96 million to be distributed among the other classes. In the proportional scaleback method, that amount is assigned to each class in proportion to the originally proposed increase after FDR. That calculation is shown in Column (12).

Thus, in Column (12), I distribute the $3.51 million in proportion to the rate increases after FDR, as shown in Column (9). For example, the Column (9) increase for the residential class is $20.24 million, which represents 97.0 percent of the increase of $20.85 million after FDR. The residential class is therefore assigned a credit of 97.0 percent of the $4.96 million in column (12), or $4.81 million.

This adjustment brings the overall revenues down to the allowed costs, as shown in Column (13).

Q. At a $10.0 million reduction in NFGD's proposed rate increase, what is the impact of your FDR proposal?

A. Under my proposal, rate increases are assigned only to the residential and SC&PA LE250 rate classes. For those classes, the residential percentage increase is 20.6 percent, compared to NFGD's proposed increase for that class of 27.0 percent. Moreover, the residential class rate increase is modestly above the system average increase of 15.1 percent, recognizing the fact that the residential class is subsidized under every COSS filed by NFGD in this proceeding. The rate increase for the SC&PA LE250 class is a little more than half that of the residential class and modestly below system average, at 11.1 percent, reflecting the fact that that class has a rate of return above system average in all COSSs filed by NFGD. These rate increases are well within the usual "rule-of-thumb" that rate increases be no more than 1.5 to 2.0 times system average.

Moreover, with the reduced revenue requirement, the LVIS and LIS class produce revenues that are reasonably consistent with allocated cost. Thus, I have not attempted to conduct a detailed analysis to determine whether the competitive threats referenced by NFGD are credible and that these customers should be subsidized.

Q. Can you provide an overall summary of the impacts of your proposal?

A. Table IEc-10 shows my proposed rate increase for each rate class. It also shows class revenue-cost ratios at present rates and at the rates that would result from a $10.0 million reduction in the revenue requirement and the FDR that I propose. As that table shows, all rate classes make significant progress toward cost-based rates under my proposal. Moreover, while the LVIS and LIS classes receive subsidies in my scenario, those

subsidies are much lower than those implied by NFGD's full revenue requirement proposal.

Table IEc-10
IEc Proposed Allocation of Revenue Increase with FDR
Assumed Reduction of $10.0 Million in NFGD Revenue Requirement

	Rate Increase $mm	Percent Distribution Increase	Present Revenue-Cost Ratio	Proposed Revenue-Cost Ratio
Residential	15.423	20.6%	91.9%	97.0%
SC&PA LE250	0.469	11.1%	107.0%	104.4%
SC&PA GT250	--	0.0%	135.8%	113.2%
LC&PA	--	0.0%	135.4%	112.6%
SVIS	--	0.0%	160.8%	142.6%
IVIS	--	0.0%	132.7%	112.5%
LVIS	--	0.0%	122.4%	105.4%
LIS	--	0.0%	110.6%	98.7%
Total	**15.892**	**15.1%**	**100.0%**	**100.0%**

Notes:
1) Revenue-cost ratios are measured based on average of four COSS methodologies.
2) Detailed calculations are provided in electronic workpapers and Exhibit IEc-4.

6. The Proposed Revenue Decoupling Mechanism

Q. Please summarize your understanding of NFGD's proposed RDM.

A. NFGD is proposing a RDM under Rider I, the Enhanced Energy Efficiency Program Cost Recovery Rider (also known as the "EEE Rider"), whereby NFGD would recover any lost distribution margin associated with reduced consumption in average usage per account. Through the EEE rider, the margin lost due to usage declines per account would be recovered by a surcharge applied across all accounts within the customer class. NFGD is proposing to apply the EEE Rider to customers within the residential, commercial/public authority, and small volume industrial classes. Each customer class would have its own separately calculated EEE rate.

The first step in computing the EEE surcharge is to subtract the annual usage per account from an imputed annual usage per account. Assuming this difference is negative (i.e., indicating a decline in usage per account), the amount of total lost margin is calculated by multiplying the total annual consumption difference with the sum of the tailblock margin

and LIRA Rider surcharge for the respective classes. The EEE surcharge would then be total lost margin divided by the annual normalized consumption.

The mechanism is designed to be bi-directional. That is, if the difference between annual usage per account and the imputed annual usage per account is positive (i.e., reflecting an increase in usage per account), the EEE rate calculation would result in an EEE credit on the customer bill.

In addition, the EEE mechanism as proposed by NFGD includes a weather normalization effect. That is, the changes in usage per account for the EEE calculation reflect both weather and conservation effects. As NFGD readily admits, a revenue decoupling mechanism could be devised that adjusts only for weather-normalized changes in usage per account, but that is not the Company's proposal. As noted above, NFGD is willing to reduce its RoE claim if the EEE rider is approved with the weather normalization provision.

Q. What is NFGD's rationale for implementing an RDM?

A. NFGD argues that it wants to be a good public citizen and encourage energy conservation. However, because its distribution rates are substantially based on volumetric charges while its costs are generally fixed in the short-run, it loses margin each time a customer conserves. Thus, NFGD argues that it has no economic incentive to encourage conservation; in fact, it has an economic incentive to discourage conservation.

Q. Is NFGD's assessment of the economic incentives correct?

A. From a narrow, short-term focus, it is. In the short-run, reductions in use per customer result in lower earnings for NFGD. However, in the longer-term, NFGD has the opportunity to file base rates cases to reflect the lower consumption levels that result from conservation. Moreover, NFGD may potentially experience longer-term benefits from more efficient use of natural gas, including increased market share and a modest

benefit to the local economy.[24] Finally, as NFGD recognizes, it earns public relations benefits from encouraging conservation.

Q. Is it necessary that NGDCs like Distribution be a primary instrument for energy conservation in Pennsylvania?

A. I do not believe so. Requiring NGDCs to encourage conservation is akin to requiring Exxon-Mobil to encourage automotive fuel economy.

The motivation for utilities to encourage and even subsidize conservation comes out of an economic environment that is very different than the present. In the 1970s and 1980s, when the cost of new energy supply assets (particularly electric generation) was much higher than the average cost of generation, utilities faced the opposite incentives to those now faced by NFGD. That is, increases in demand would cause utility costs to increase more than the associated revenues. These higher costs would then be passed on to ratepayers in the form of higher electric rates. Because the price signals, based on average costs, were below the incremental costs of providing service, it was often less expensive for utilities to subsidize conservation than to install new energy supply capacity. This economic environment led, quite rationally, to the development of utility-financed demand side management ("DSM") programs. It also engendered the idea among ratepayers and regulators that it was the local utility's job to encourage conservation.

As I mentioned, however, that economic environment no longer exists. The question then becomes whether the regulator should continue to try to require the utility to serve as a primary motivating force for encouraging conservation, in light of the changed economic circumstances. And my recommendation is that the Commission move away from this model, for several reasons.

First, as NFGD indicates, it will at best have mixed motives for encouraging conservation. As I explain below, to improve NFGD's motivations, it will be necessary

[24] I recognize that the market share of natural gas for home heating in Distribution's service territory is already fairly high, and therefore NFGD's potential for load and customer growth is relatively low. Nevertheless, Mr. Meinl's testimony indicates that NFGD believes that customers can achieve significant savings by switching to natural gas. (NFGD Statement No. 11-S at page 7) Moreover, it must be recognized that approving Distribution's proposal would set a precedent for other NGDCs in Pennsylvania, where there is more inter-fuel competition. These other NGDCs may experience a greater longer-term benefit from efficient use of natural gas than NFGD.

for the Commission to move away from one of the precepts of test-year regulation, namely the avoidance of single-issue ratemaking. Second, customers are already facing very significant economic incentives to conserve. The rapid rise in natural gas prices over the past few years will have a profound effect on conservation and efficient energy use. NFGD is already experiencing the demand-reduction effects of this price rise, and these effects will almost certainly continue.[25] Third, other private businesses have incentives to encourage conservation. Sellers of home insulation surely tout the benefits of using those products, and they may offer incentives such as discounted installation costs to increase sales. Similarly, manufacturers and sellers of set-back thermostats (not to mention electricians) have incentives to encourage the use of these products. Finally, to the extent that it is government policy that energy conservation be encouraged, government-financed education programs can be adopted.

Q. You indicated that NFGD's proposed RDM is an example of single-issue ratemaking. Can you explain what you mean?

A. Yes. When a utility has its base rates set for a test year, the revenue requirement reflects a wide range of business assumptions. These assumptions include the load forecast (usually based on weather-normalized load), the utility's forecast capital and operating costs, and its rate base. Its operating costs are based on numerous factors, including inflation, labor costs, pension and OPEB costs, and its capital costs are based on interest rates, income tax rates, etc. Once those base rates are set, any and all of those assumptions may change. The effects of the changes can be to either raise or lower the rate increase that would have been awarded, if those changes had been known.

Single-issue ratemaking involves making rate adjustments for one, or even a small subset, of all of the factors that can influence a utility's rates. There is a strong temptation for a utility to argue that it should be allowed to adjust its rates for one particular factor that is causing its earnings to decline, without affording the regulator and ratepayer advocates the opportunity to evaluate all of the other issues that may be providing a benefit to

[25] As economists say, the long-run price elasticity of energy demand is much higher than the short-run price elasticity. Energy consumption is significantly determined by the capital stock of energy consuming equipment. For example, increases in natural gas prices make high efficiency home furnaces much more economically attractive. However, not every homeowner will install a new furnace when gas prices increase. Over time, however, the price increase will cause a shift to more efficient furnaces.

earnings, relative to the base rates assumptions. For that reason, single-issue ratemaking is generally avoided by regulators.

In this case, NFGD argues that the single-issue is the trend in reduced consumption per customer, which causes its earnings to decline. NFGD therefore proposes an automatic adjustment mechanism for this particular issue, without the opportunity for regulatory review of all of the other factors, including the beneficial ones.

Q. What kind of changes tend to have a dampening effect on base rates?

A. One common example is increases in both number of customers and throughput volumes. For an NGDC, the incremental cost of providing service to new customers or increased loads is less than the revenues earned from those customers. (In fact, most utilities have contribution policies for new customers to ensure that new customers provide sufficient revenues to recover the incremental costs.) Thus, growth in customer count can offset the effects of declining use per customer. In addition, utility capital costs are based on test year rate base. For mature utilities, it can be the case that depreciation exceeds new investment costs, thereby resulting in capital cost declines over time. Also, utilities may experience cost savings through operating efficiencies and improvements in labor productivity. In addition, modifications such as NFGD's conversion of new employees to defined contribution pension plans and the gradual elimination of past service liabilities can cause costs to decline.

Q. Is NFGD likely to experience any of these gains in earnings?

A. To be quite frank, I do not expect so. NFGD's customer growth has been negligible (or negative). Moreover, in the three base rates cases that NFGD has filed in the past four years, there is no obvious reduction in the dollar value of its operating costs.

Nevertheless, establishing a RDM at NFGD will establish a precedent for other NGDCs in Pennsylvania, which may not be experiencing the same cost and growth trends. Moreover, it would establish a precedent for other single-issue ratemaking schemes.

Q. Do you have any other concerns about establishing an RDM at NFGD at this time?

A. Yes I do. One objective of the RDM is to reduce the need for expensive base rates proceedings. By making automatic upward adjustments to rates to offset declines in per-customer use, this mechanism will implicitly reduce the ability of those customer classes

whose rates exceed allocated costs to make progress toward cost-based rates in the base rates proceedings. If NFGD's rates were currently based on cost, this issue would not be important. However, as I explained above, all four cost allocation methodologies indicate that small business customers are paying revenues in excess of allocated costs, and are very likely to continue to do so at the end of this proceeding.

Until such time as NFGD gets its rates set equal to allocated costs, any automatic adjustment mechanism that has the effect of deferring base rates proceedings is unduly discriminatory to those rate classes that are providing the subsidies. As a matter of basic fairness to small business customers at NFGD who have been net providers of subsidies for years, it would be grossly inequitable to establish automatic rate adjustment mechanisms at this time.

Q. NFGD argues that, as proposed, its RDM incorporates a weather-normalization effect, because changes in usage per customer due to weather factors will be incorporated into its tariff charge adjustments. Mr. Meinl indicates that NFGD would be willing to reduce its claimed return on equity in exchange for adoption of the RDM, if it includes this weather-related aspect of the proposal. Please comment.

A. First, as NFGD recognizes, the RDM proposal is very different from a typical weather-normalization adjustment. A traditional weather normalization mechanism can provide risk reduction benefits to both the utility and to ratepayers, because it will cause rates to be adjusted in "real time" with changes in the weather. For example, the Philadelphia Gas Works' ("PGW") weather normalization clause adjusts distribution rates based on the difference between actual heating degree days ("HDDs") in the billing cycle and the normalized HDDs for that cycle. Thus, when the weather is colder than normal and ratepayers' gas consumption is high, the weather normalization mechanism provides a modest offset to high bills by setting distribution rates lower than they otherwise would be. In effect, the bills paid by ratepayers and the margins earned by the utility are stabilized from year to year.

This pattern is not the same for NFGD's proposed RDM. NFGD proposes to make the usage adjustment annually. Thus, for example, if NFGD experiences a relatively warm winter, it will increase its rates associated with the weather-related reduction in usage per

customer. However, because it is an annual adjustment, that rate increase will be imposed on ratepayers in the next winter, which may of course be colder than normal. In short, NFGD's proposal provides more longer-term revenue stability for itself, but does not provide the short-term revenue stability for the ratepayers associated with a weather normalization clause.

In addition, NFGD's proposed adjustment to the return on equity is very small. NFGD's expert Mr. Hanley has added only 16 basis points to NFGD's claimed return on equity to account for the lack of a weather normalization clause. By contrast, the RDM proposed by NFGD would eliminate one of its major sources of financial risk. Because this factor is such a large component of NFGD's risk, any adjustment to the return on equity should represent a significant percentage of the difference between the allowed return on equity without RDM and the utility's incremental cost of debt.

7. The Proposed Merchant Function Charge

Q. Please summarize NFGD's proposal for a Merchant Function Charge ("MFC").

A. NFGD is proposing to establish a MFC that is designed to recover certain base rates costs that are incurred on behalf of gas sales customers. It will be imposed only on those customers who use NFGD as their natural gas supplier. As proposed, the MFC is based on the Company's costs related to the working capital associated with gas in storage and the uncollectibles costs associated with gas sales. Moreover, NFGD proposes to establish this charge as a percentage of the PGC charge, so that when PGC costs move up and down, the MFC will as well.

Note also that NFGD proposes that this charge be differentiated by rate class. The proposed residential charge is about 39 cents per Mcf (at approximately 3.07 percent of the PGC charge), while for commercial customers it is 10 cents per Mcf (at approximately 0.81 percent of PGC costs), reflecting the higher uncollectibles rate for residential customers.

NFGD also recognizes that NGSs may cherry-pick low collection risk customers, leaving higher risk customers on sales service. In effect, low-risk customers could avoid their obligation to contribute to the funding of gas sales uncollectibles costs in the MFC by opting for transportation service. (They cannot avoid that obligation now, because

uncollectibles are recovered in base rates.) NFGD therefore indicates that it will review the program after one-year and make adjustments to the MFC if necessary.[26]

Q. Is NFGD's proposal for an MFC consistent with sound cost causation principles?

A. In my view it is. The genesis for this proposal comes from the basic issue that the Commission has historically used the PGC charge for two different purposes. The PGC charge was originally established to consist only of relatively volatile gas supply costs, including both commodity and upstream pipeline and storage costs, that were deemed to be outside the control of the NGDC. Because the costs were deemed to be beyond the control of the NGDC, they were subject to regular reconciliation, outside of base rates cases. Because they were volatile, these costs were passed on to customers through PGC charges that varied quarterly. My understanding of the PGC charge is that it was not originally intended to include all costs associated with providing system gas supply, because it was set up during a period of bundled rates.

However, when rates were unbundled, the PGC charge was adopted as the shopping credit. Because of its history, however, this shopping credit necessarily excluded certain costs directly associated with gas supply, notably the working capital, uncollectibles and company supply costs -- costs that were deemed to be at least partly under the control of the NGDC. The PGC charge also excluded any marketing and administrative costs incurred by the NGDC related to gas supply (that gas marketers often argue should be included in the gas supply charge).

NFGD's proposal in this case is to take the specific costs that are directly related to providing gas supply services and assign them only to gas supply customers. By "directly related," I refer to costs that will increase when gas sales increase, and costs that will decrease if customers switch to supply from NGSs. Both of the cost items that NFGD proposes to include in this charge generally meet that definition. Regarding uncollectibles costs, for those customers who switch to alternative suppliers, the risk of

[26] As I explain further below, NFGD also proposes to implement a receivables purchase program for NGSs who use NFGD's billing services. Because NFGD will purchase those receivables at a discount, those NGSs will not be able to benefit by selecting only low-risk customers. Thus, if that program is adopted as well, any adjustments at the end of the year to the MFC would apply only to customers whose NGSs do not use NFGD's billing option.

non-payment of the gas supply charge shifts to those suppliers. Therefore, unless the suppliers can somehow identify and serve only low-risk customers, NFGD's costs will decline if customers shop. Regarding the working capital costs, these are costs associated with sales customers' gas held in storage by NFGD. If customers shift to NGSs, NFGD will be able to reduce its gas storage inventory and its rate base will decline.

Q. What is the rationale for proposing this change?

A. NFGD indicates that it offers this proposal as an effort to spur competition. Under current rates, competing NGSs incur the costs for uncollectibles and gas in storage and must recover it in the rates they charge to customers. However, they compete against the utility PGC charge that is not burdened with those costs. Thus, they are at a competitive disadvantage. In theory, NFGD's proposal may improve competition.

However, from a practical perspective, this proposal will only directly affect the rates for the retail transportation customers (those served under Schedule SATC), for which there are currently almost no volumes. Because NFGD establishes rates separately for MMT and DMT transportation customers, it is not obvious whether this change will have any effect on those rates, since they are not directly comparable to the sales rates.

In addition, I expect that one of NFGD's objectives for this charge is to reduce its exposure to gas price fluctuations. When gas prices rise, NFGD's uncollectibles and working capital costs increase, but they get no additional revenues from the traditional PGC. By establishing the MFC as a percentage of purchased gas costs, its exposure to those fluctuations is reduced.

Q. What, then, is your recommendation regarding this proposal?

A. I have no objection to NFGD establishing an MFC, based on gas sales uncollectibles costs and gas-in-storage working capital costs, particularly since the proposal leaves open the possibility of an adjustment for potential cherry-picking by NGSs.

Moreover, I do not have a conceptual disagreement with the idea of basing this charge on a percentage of the PGC charge, since these costs would generally be expected to fluctuate with overall gas prices. If the MFC is adopted on this basis, the Commission should recognize that this proposal will modestly reduce NFGD's revenue volatility, and

therefore it may wish to make a modest downward adjustment to NFGD's allowed rate of return on equity.

Further, while I am not an attorney, I am informed by OSBA counsel that applying this charge as a percentage of the PGC may be unlawful.

I am informed by counsel that, to the extent the OSBA determines that NFGD's proposal is not consistent with the law, it will present its legal arguments in its briefs in this proceeding.

8. The Proposed Receivables Purchase Pilot Program

Q. Please summarize NFGD's proposal for purchasing receivables from NGSs.

A. NFGD is also proposing a two-year pilot program for the purchase of receivables from retail suppliers serving small customers. The customers who take retail transportation service take it under NFGD's SATC tariff, and the NGSs provide service under the SATS tariff. NFGD reports that 81 of its 210,000 customers take service under Schedule SATC, accounting for about 0.2 percent of NFGD's total throughput.

The essence of the proposal is that NFGD will purchase the receivables of those NGSs who use NFGD's billing system at a discounted rate. As I understand it, NFGD will require NGSs who use the Company's billing system to accept this program. The discount is 3.07 percent for residential customers and 0.81 percent for all other customers (reflecting the higher risk of uncollectibles for residential customers). The percentage discounts are the same percentages used by the Company to establish the MFC, and they therefore include both uncollectibles and gas-in-storage working capital costs.

In exchange for the discount, the Company will assume collection responsibility and risk. The NGS will be paid 23 days after the bill is issued, and NFGD will retain the right to impose late charges and retain those revenues.

NFGD proposes to establish the program for a minimum of two years, with the agreement cancelable by NFGD with one year notice to the NGSs.

Q. *What is the motivation for this program?*

A. NFGD indicates that this program is designed to encourage retail competition.

Q. What are your views regarding this proposal?

A. The advantage of the proposal is that it may help competition, by making it less costly for NGSs to collect payment from retail customers, thereby improving the attractiveness of this market to NGSs.

I have a couple of concerns about the proposal. First, NFGD appears to set the discount too high. As I mentioned, NFGD includes the working capital costs for gas-in-storage in the discount percentage. However, NGSs supplying retail gas customers will also incur these costs independently. In effect, under NFGD's proposal, they will pay for these costs twice. Second, by transferring the collection responsibility to NFGD, NGSs will have less incentive to provide superior customer service. For example if the NGS changes its rates, NFGD will simply pass those rates on to the customers, and will assume responsibility for collecting those bills. However, NFGD will not be able to explain why the bills have changed, and the NGS may have little incentive to respond promptly to customer questions.

9. The Proposed Seasonalization of Purchased Gas Cost Rates

Q. Please summarize NFGD's proposal for seasonalizing purchased gas cost rates.

A. NFGD splits its PGC charges into commodity ("PGCC") and demand ("PGDC") components. The commodity portion includes the cost of the gas itself, plus the commodity charges from the interstate pipeline suppliers for transmission and storage service. The PGDC includes the demand charges from the pipelines for transmission and storage service.

In its filing, NFGD proposes to establish seasonal rates for recovery of the PGDC; more specifically, it proposes to recover all of its PGDC costs in the winter months (December through March). At the PGDC rates used by NFGD in its filing, this proposal implies a PGDC winter charge of about $2.64 per Mcf, compared to an annual charge of $1.75 per Mcf.[27]

Because the seasonalization proposal applies to purchased gas costs, it applies primarily to PGC customers. However, because part of NFGD's PGDC costs are incurred to

[27] Note also that NFGD proposes to seasonalize its proposed MFC, presumably to reflect the fact that the gas-in-storage working capital costs are winter-related. (Based on my analysis, it does not appear that NFGD has assumed that all MFC working capital costs are related to winter consumption, for reasons that are unknown at this writing.) Conceptually, I agree that gas-in-storage working capital costs are causally related to winter consumption.

provide services for retail gas transportation customers (who take service under Schedule SATC), those customers will also see a modest seasonal differential.[28]

Q. Is this proposal consistent with sound cost causation principles?

A. No, it is not. On the surface, NFGD's proposal sounds like it should make sense. Demand charges from upstream pipelines and storage facilities seem like they should be related only to winter season demand, and therefore it does not seem unreasonable to recover those costs only from winter volumes. However, when this matter is considered more carefully, it becomes clear that the cost causation factors for storage-related demand costs are very different from the cost causation factors for "long-haul" pipeline demand costs. Just because an interstate pipeline imposes a "demand" charge, it does not mean that the NGDC will decide how much capacity it needs based on the peak or even winter demands of its customers. An NGDC uses very different criteria for determining how much "long-haul" pipeline capacity to buy, and how much storage capacity to buy.

The issue arises because it is usually much more expensive to purchase peak day capacity in the form of pipeline capacity than it is to buy peak day capacity through storage supplies. Thus, NGDCs (including NFGD) try to operate their long-haul pipeline capacity at very high load factors, and to meet their peak day demands primarily through storage contracts or other peak shaving options.

In the ideal circumstances, an NGDC will purchase enough pipeline capacity to meet its average daily load. It will then use that capacity to haul the same amount of gas every day for the vast majority of the distance from the wellhead either to the city gate or to its storage facilities. In the summer, gas will be injected into storage. In the winter, gas will be withdrawn from storage.

Thus, all costs associated with storage injection, withdrawal and delivery from storage to the city gate are winter-related costs. In fact, summer consumption should be eligible for a cost credit for reducing the need for storage capacity. There is no theoretical reason not to recover storage/load balancing costs from winter volumes.

[28] At the PGC rates used in NFGD's filing, SATC customers will face a winter charge for load balancing services of 46.32 cents per Mcf, compared to current average annual rates of 30.39 cents per Mcf.

However, that argument does not hold for pipeline demand charges. The interstate pipeline capacity is generally sized to meet annual demands. Increases in either summer or winter consumption will increase the need for pipeline capacity. (Increases in summer consumption will also then reduce the need for storage capacity.)

Thus, it is simply wrong to assume that all pipeline demand charges are related to winter consumption.

Q. Are you aware of any real-world examples of the problems associated with NFGD's proposals?

A. Yes. Two major gas distribution utilities in Canada used cost allocation methodologies that were conceptually similar to that implied by NFGD's proposal in this matter. Both utilities proposed to allocate all pipeline and storage demand costs on a peak demand basis. Both utilities then discovered that this allocation approach resulted in rates for the high load factor classes that were lower than the 100 percent load factor pipeline toll. In effect, a 100 percent load factor customer could purchase long-haul transportation capacity from the NGDC's unbundled rates at a price that was lower than that charged by the pipeline.

Such a result was obviously unreasonable, and both NGDCs eventually adopted cost allocation approaches in which pipeline capacity costs were generally allocated on a volumetric basis, and storage capacity costs were generally allocated on an excess demand basis.

Q. Mr. Knecht, is it your testimony that NFGD has understated the cost differential between providing winter and non-winter service?

A. No. NFGD has proposed only to seasonalize one component of its costs, while other costs are likely to have seasonal components. As Mr. Meinl recognizes in his supplemental direct testimony (at page 11), gas commodity costs have a seasonal component that could be recognized in seasonal PGC rate differentials. Moreover, those distribution costs that are related to peak demand are sized to meet winter peak demands, and therefore can very credibly be defined as partly or wholly winter-related. However, NFGD has not offered either of these options as a specific proposal, and evaluating either option would require detailed analysis that is beyond the scope of this testimony. For

example, seasonalizing gas commodity costs would require a thorough review of NFGD's gas procurement policies, including all of its price hedging arrangements, to develop the actual seasonal differentials contained in its current PGC rates. Absent such analysis, I cannot recommend that either of these alternative seasonal approaches be adopted.

Q. What is your recommendation regarding NFGD's proposal for seasonal rates for PGDC charges?

A. NFGD's proposal is not consistent with sound cost causation regarding the way it incurs those costs. NFGD's proposal could have the effect of causing higher load factor transportation customers to switch back to sales service, and cause NFGD to incur higher pipeline costs than these customers would provide under NFGD's proposed seasonal PGDC rates. Thus, as proposed, NFGD's seasonalization of purchased gas costs should be rejected.

10. Rate Design for Commercial and Public Authority Rate Classes

Q. Please summarize the rate design proposals for NFGD for the C&PA customers that you address in this section of your testimony.

A. As I mentioned in my summary, NFGD puts forward two alternative rate design packages for C&PA customers. One of those packages is linked with its seasonal PGDC rate proposal (the "seasonal rate design") and one is generally consistent with its existing tariff structure (the "non-seasonal rate design"). This section of my testimony will address certain aspects of both proposals. In particular, I review the following:

- NFGD's proposed increases to the monthly customer charges for the SC&PA classes under both rate design proposals;
- The proposal to significantly shift cost recovery from the tail block to the first block charges for the SC&PA classes in the seasonal rate design; and,
- The proposal to impose much larger commodity charge increases on LC&PA sales customers than on LC&PA transportation customers.

As I will explain, all of these proposals should be modified.

Q. Please summarize NFGD's proposal for changes to the distribution charges for SC&PA customers.

A. Table IEc-11 below shows NFGD's proposals for distribution rates under both the seasonal and non-seasonal rate designs:

Table IEc-11
NFGD Proposed Rates for SC&PA Classes

	Present Rates	Proposed Rates		
		Non-Seas.	Seasonal	Percent
SC&PA LE 250				
Customer Charge	$17.00	$27.50	$27.50	61.8%
First 5 Mcf	$2.6041	$2.5129	$4.2290	-3.5 / 62.4%
Over 5 Mcf	$2.2994	$2.2069	$1.2321	-4.0 / -53.6%
SC&PA GT 250				
Customer Charge	$26.50	$35.50	$35.50	34.0%
First 20 Mcf	$1.9583	$2.3712	$4.0873	21.1% / 108.7%
Over 20 Mcf	$1.8271	$2.2057	$1.1158	20.7% / -38.9%

Note: Percentage increases are reported as non-seasonal/seasonal where NFGD proposes different rates.

These proposals obviously exhibit a number of significant departures from the current tariff. For the SC&PA LE250 non-seasonal tariff, NFGD proposes an enormous increase in the customer charge, with modest reductions in both commodity blocks. For the SC&PA GT250 customers, NFGD's non-seasonal tariff proposal is reasonably consistent with the existing structure, although a larger percentage increase is applied to the customer charge than to the commodity block charges.

For the seasonal tariff proposal for both classes, NFGD combines very large increases in the customer charge with enormous increases in the first block commodity charges, offset by large reductions in the tail block charges.

Q. Well, let's start with the non-seasonal rate design proposal for both classes. Are NFGD's proposals justified on the basis of allocated costs?

A. For the SC&PA LE250 class, the customer-related costs at proposed rates in NFGD's COSSs average about $32 per month, ranging from $28 to $36 per month depending on the methodology chosen.

For the SC&PA GT250 class, the customer-related costs average $39 per month, ranging from $35 to $43.

However, it is important to recognize that NFGD's tariff design for these two rate classes recovers these customer-related costs in two ways. First, it recovers customer-related costs in the customer charge. Second, however, it recovers customer-related costs in the first block tariff premium. NFGD's approach is similar to that used by many NGDCs. Because customer charges are often set below allocated customer costs for reasons of customer (and regulatory) acceptance, utilities often set a higher first block charge to recover those costs.

Q. But Mr. Knecht, doesn't NFGD also use a declining block tariff charge to recognize that larger customers' demand-related costs are lower per-unit of throughput than for smaller customers in these classes?

A. No it does not. NFGD has no evidence that larger customers within these classes are any less costly to serve per-unit of throughput, except for the customer-related cost effect. At some NGDCs, larger customers within the commercial classes have higher load factors than the smaller customers within the class, and they therefore cost less to serve per unit of throughput. In those cases, it is not unreasonable to reflect that pattern with declining block rates. However, at NFGD, the SC&PA classes contain relatively small customers, and it is unlikely that larger customers within these classes exhibit higher load factors than smaller customers. In fact, it is possible that the smaller customers within the classes are non-heat customers with higher load factors, while the larger customers within the class are heat customers with low load factors.

Thus, NFGD's only justification for the declining block rate for these classes is to supplement the recovery of the customer costs.

Q. With that explanation, how do the customer costs recovered in NFGD's proposed rates compare with the customer costs from NFGD's COSS?

A. For the SC&PA LE250 class, I calculate that NFGD's proposed tariff will recover approximately $28.50 in customer-related costs, compared to the allocated cost range of $28 to $36. Thus, from a cost perspective, NFGD's proposal is just barely justified.

For the SC&PA GT250 class, the proposed tariff will recover approximately $38 per month, compared to the COSS range of $35 to $43 per month. Again, NFGD's proposal is either barely justified or perhaps slightly high.

Q. What other considerations come into play when setting customer charges?

A. Most NGDCs consider customer acceptance and the principle of gradualism as criteria when designing rates. In this case, NFGD's proposal for SC&PA LE250 to increase the customer charge by 61.5 percent, compared to an average increase for the class of 27.4 percent, is certainly pushing the limits of gradualism. I recommend that, for the SC&PA LE250 class, the increase in the customer charge be no more than 1.5 times the average increase for the class, at NFGD's proposed overall increase.

Q. *What are your specific recommendations for setting the customer charge for the* SC&PA rate classes?

A. For SC&PA LE 250, the limit of a 1.5 times system average recommendation would still permit an increase in the customer charge to about $24 per month, at NFGD's overall proposal. Of course, if NFGD's revenue allocation to this class is reduced, the increase in the customer charge would be reduced proportionately.

For the SC&PA GT250 class, I recommend that the customer charge be set such that it will recover the low-end of the customer-related costs from the COSS studies, namely $35 per month. I recommend using the low end of the range because it is likely that the COSSs overstate customer-related costs for this class. Within this class, the larger customers generally require more expensive meters, services and regulators than the small customers within the class. However, all of this plant is classified as customer related. If the customer charge is set at the full customer cost, smaller customers in the class will implicitly be contributing to the cost of the more expensive meters of the larger customers.

At NFGD's proposed revenue requirement, I estimate the customer charge needed to recover $35 per month in customer costs (in conjunction with the first block tariff premium) is approximately $32.50 per month, an increase of 22.6 percent or a little below NFGD's proposed increase for the class.

If NFGD's proposed increase for the SC&PA GT250 class is scaled back, I recommend that the customer charge be set at the lesser of $32.50 or the average increase for the class applied to the current customer cost. Thus, if the allowed increase for the SC&PA GT250 class is set at 10 percent, the customer charge would increase from $26.50 to $29.15.

Q. Please refer now to NFGD's seasonal proposal for the SC&PA classes. Are these proposals consistent with NFGD's allocated costs?

A. No they are not. For SC&PA LE250, NFGD's seasonal rate design proposal will implicitly recover customer-related costs in excess of $37 per month, compared to a cost basis of $28 to $36 per month.

Similarly, for SC&PA GT250, NFGD's seasonal rate design proposal will recover more than $77 per month in customer-related costs, compared to a cost basis of $35 to $43 per month.

These proposals are simply not consistent with NFGD's COSS analyses. Moreover, they represent a massive shift in the rate burden from large customers to small customers within each of these classes. As NFGD has no cost basis for this redistribution, I recommend that it be rejected.

Q. Can you respond to Mr. Meinl's assertions that NFGD's costs are essentially fixed, and therefore it is appropriate to recover them with fixed charges?

A. Yes. Mr. Meinl argues that, because most of NFGD's distribution costs are associated with plant that is already bought and paid for, its costs will not vary as throughput or peak demand levels. In the short-run, Mr. Meinl is correct -- these costs are essentially fixed.

However, NFGD's COSSs do not assume that these costs are fixed. NFGD's COSSs assume that its demand-related distribution costs will, over the long term, vary with the peak demands on the system. As Ms. Truitt testifies, demand-related costs are related to customers' peak load requirements, and they are not impacted by the number of customers or gas throughput.

Thus, for example, if some customers within the SC&PA classes increase their consumption (and peak demand) levels, these customers will cause NFGD's COSSs to

allocate more demand-related costs to the class. Unless demand-related costs are recovered in the commodity charges, the increase in costs allocated to the class will be disproportionately borne by the smaller customers within the class.

It is therefore inappropriate to recover costs that are classified as demand-related in the COSS in a customer charge, even if those costs are mostly fixed in the short-run. It is equally inappropriate to burden the first block commodity charge with those costs, because all demands contribute equally to costs allocated to the SC&PA classes.

Q. What, then, is your proposal for SC&PA commodity charge increases?

A. I recommend that the customer charges be set as I explained earlier. For the approved class revenue increase that is not recovered by the customer charge increase, a constant percentage markup should be applied to the current commodity charges.

Q. Let's turn now to the LC&PA rate design. What is NFGD's distribution rate design proposal for these customers?

A. For these customers, NFGD does not propose radically different seasonal and non-seasonal options. However, for this class, it is important to recognize that there are significant volumes associated with both sales and transportation customers. With that background, Table IEc-12 below summarizes NFGD's distribution rate design proposal for this class.

Table IEc-12
NFGD Proposed Rates for LC&PA Classes

	Present Rates	Proposed Rates	
		Rate	Percent
Sales Customers			
Customer Charge	$121.01	$121.01	0.0%
0-300 Mcf	$1.2753	$2.0975	64.5%
300-2000 Mcf	$1.1802	$1.9391	64.3%
Over 2000 Mcf	$1.0059	$1.6487	63.9%
MMT/DMT Customers			
Customer Charge	$121.01	$121.01	0.0%
Admin Charge	$70.00	$ 0.00	-100.0%
Intrastate Mcf	$1.1876	$1.6877	42.1%
Interstate Mcf	$1.2757	$1.6877	32.3%

Q. Well, let's break this one up into its pieces. Do you agree with NFGD's proposal to impose no increase to the customer charge?

A. Yes I do. The customer cost basis for LC&PA is $63 to $71 per month. While a reduction in the customer charge is justified on a cost basis, I accept NFGD's proposal for reasons of gradualism and customer acceptance. However, if the Commission materially reduces the rate increase imposed on LC&PA customers (as I recommend), it may be reasonable to scale back all of the proposed LC&PA charges, thereby including a reduction in the current LC&PA customer charge.

Q. Do you agree with NFGD's proposal to eliminate the administrative fee for transportation customers?

A. I do. While NFGD likely incurs costs associated with nominations and billings for these customers, it is not clear that these costs would be avoided if these customers returned to sales service. Because purchased gas cost charges are calculated on an incremental cost basis, it is not unreasonable to compute transportation administrative charges using the same approach. Absent solid evidence that NFGD incurs avoidable costs associated with providing these administrative services, I recommend that no additional charges be imposed on transportation customers.

Moreover, because it has been imposed as a cost per bill, the administrative charge tends to discourage shopping by the smaller customers within this rate class.

Q. Do you agree with NFGD's proposal to harmonize the transportation rates for delivery of interstate and intrastate gas?

A. Yes I do. There is no distribution cost to serve difference between delivering inter- and intra-state gas, and the differential adds unnecessary complexity to the tariff.

Q. Do you agree with NFGD's proposal to assign a much larger percentage increase to its sales customer commodity charges than to its transportation customer commodity charges?

A. No I do not. NFGD offers no evidence as to why transportation customers cost any less to serve per unit of throughput than sales customers. However, under NFGD's proposed rates, the average transportation customer (with a monthly throughput of 517 Mcf) would

pay $2.03 per Mcf in commodity charges under the sales rate schedules but would pay only $1.69 per Mcf under the transportation schedules.

Because there is no cost basis for this proposal to transfer the revenue requirement from transportation customers to sales customers, I recommend that NFGD's proposal be modified such that the commodity charge increases for LC&PA sales and transportation customers be set at approximately the same level. At NFGD's proposed increase for that class, that percentage increase should be approximately 36.3 percent.

Q. Suppose your proposal for FDR is approved and the LC&PA class is assigned a zero increase. How would you modify the tariff charges?

A. In that event, I recommend keeping NFGD's proposal to eliminate the transportation administrative charge, and I recommend reducing the customer charge for all customers by $10 per month. The reduction in revenue associated with those changes should be recovered with an across-the-board commodity charge increase. That increase would be approximately 14.1 cents per Mcf for all commodity blocks.

Q. Does this conclude your direct testimony?

A. Yes it does.

EXHIBIT IEc-1

Résumé and Expert Testimony List

for

Robert D. Knecht

IEc

INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

Robert D. Knecht specializes in the practical application of economics, finance and management theory to issues facing public and private sector clients. Mr. Knecht has more than twenty years of consulting experience, focusing primarily on the energy, metals, and mining industries. He has consulted to industry, law firms, and government clients, both in the U.S. and internationally. He has participated in strategic and business planning studies, project evaluations, litigation and regulatory proceedings and policy analyses. His practice currently focuses primarily on utility regulation, and he has provided analysis and expert testimony in numerous U.S. and Canadian jurisdictions. In addition, as Treasurer of IEc since 1995, Mr. Knecht is responsible for the firm's accounting, finance and tax planning, as well as administration of the firm's retirement plans. Mr. Knecht's consulting assignments include the following projects:

- For the Pennsylvania Office of Small Business Advocate, Mr. Knecht provides analysis and expert testimony in industry restructuring, base rates and purchased energy cost proceedings involving electric, steam and natural gas distribution utilities. Mr. Knecht has analyzed the economics and financial issues of electric industry restructuring, stranded cost determination, fair rate of return, claimed utility expenses, cost allocation methods and rate design issues.

- For independent power producers and industrial customers in Alberta, Mr. Knecht has provided analysis and expert testimony in a variety of electric industry proceedings, including industry restructuring, cost unbundling, stranded cost recovery, transmission rate design, cost allocation and rate design.

- For industrial customers in Québec, Mr. Knecht has prepared economic analysis and expert testimony in regulatory proceedings regarding cost allocation, compliance with legislative requirements for cross-subsidization, and rate design.

- As part of international teams of experts, Mr. Knecht has prepared the economic and financial analysis for industry restructuring studies involving the steel and iron ore industries in Venezuela, Poland, and Nigeria.

- For the U.S. Department of Justice and for several private sector clients, Mr. Knecht has prepared analyses of economic damages in a variety of litigation matters, including ERISA discrimination, breach of contract, fraudulent conveyance, natural resource damages and anti-trust cases.

- Mr. Knecht participates in numerous projects with colleagues at IEc preparing economic and environmental analyses associated with energy and utility industries for the U.S. Environmental Protection Agency.

Mr. Knecht holds a M.S. in Management from the Sloan School of Management at M.I.T., with concentrations in applied economics and finance. He also holds a B.S. in Economics from M.I.T. Prior to joining Industrial Economics as a principal in 1989, Mr. Knecht worked for seven years as an economic and management consultant at Marshall Bartlett, Incorporated. He also worked for two years as an economist in the Energy Group of Data Resources, Incorporated.

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ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN UTILITY REGULATORY PROCEEDINGS

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
R-00061365	Pennsylvania Public Utility Commission	PG Energy	July 2006	Pennsylvania Office of Small Business Advocate	Merger savings, cost allocation, revenue allocation, rate design.
R-00061519	Pennsylvania Public Utility Commission	PPL Gas Utilities, Inc.	July 2006	Pennsylvania Office of Small Business Advocate	Design day weather and throughput forecasts; gas supply hedging.
R-00061518	Pennsylvania Public Utility Commission	PG Energy	July 2006	Pennsylvania Office of Small Business Advocate	Design day weather and throughput forecasts; gas supply hedging.
A-125146	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Southern Union Company	June 2006	Pennsylvania Office of Small Business Advocate	Public benefits of proposed sale of PG Energy to UGI; transfer to upstream asset contracts.
R-00061355	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2006	Pennsylvania Office of Small Business Advocate	Gas supply and hedging plan; procedural issues
R-00061296	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2006	Pennsylvania Office of Small Business Advocate	Gas procurement and procedural issues.
R-00061246	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2006	Pennsylvania Office of Small Business Advocate	Gas procurement; unaccounted for gas retention rates
2005-002 Refiling	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	February 2006	New Brunswick Public Intervenor	Cost allocation, rate design
P-00052188	Pennsylvania Public Utility Commission	Pennsylvania Power Company	December 2005	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design for POLR supplies.
R-3579-2005	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2005	AQCIE/CIFQ	Generation cost allocation; cross-subsidization; revenue allocation

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EXPERT TESTIMONY SUBMITTED IN UTILITY REGULATORY PROCEEDINGS

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
2005-002	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	August 2005	New Brunswick Public Intervenor	Cost allocation, rate design
R-00050538	Pennsylvania Public Utility Commission	PG Energy	July 2005	Pennsylvania Office of Small Business Advocate	Gas procurement diversification
R-00050540	Pennsylvania Public Utility Commission	PPL Gas Utilities, Inc.	July 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, hedging, retention rates, sharing mechanism
R-00050340	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, hedging and diversification.
R-3563-2005	Régie de l'Énergie, Québec	Hydro Québec Distribution	April 2005	AQCIE/CIFQ	Generation cost allocation; industrial demand response
R-00050264	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, risk hedging, financing costs in the gas cost rate.
R-00050216	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2005	Pennsylvania Office of Small Business Advocate	Gas supply procurement and forward pricing policies.
EB-2004-0542	Ontario Energy Board	Union Gas Limited	March 2005	Tribute Resources Inc.	Cost allocation and rate design for service to embedded storage pools.
R-00049884	Pennsylvania Public Utility Commission	Pike County Light and Power (Gas Service)	January 2005	Pennsylvania Office of Small Business Advocate	Fair rate of return, cost allocation, class revenue assignment.
R-00049656	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	December 2004	Pennsylvania Office of Small Business Advocate	Fair rate of return, uncollectibles costs, automatic rate adjustments, cost allocation, rate design.
R-3541-2004	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2004	AQCIE, CIFQ	Allocation of post-patrimonial generation costs.

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Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
C-20031302	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	July 2004	Pennsylvania Office of Small Business Advocate	Customer assistance program funding and cost allocation.
R-049255	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	June 2004	Pennsylvania Office of Small Business Advocate	Transmission and distribution cost allocation, rate design, automatic distribution increases.
P-042090 et al.	Pennsylvania Public Utility Commission	Philadelphia Gas Works	June 2004	Pennsylvania Office of Small Business Advocate	Collections and universal service cost issues.
RP-2003-0203	Ontario Energy Board	Enbridge Gas Distribution	May 2004	Vulnerable Energy Consumers Coalition et al.	Cost allocation, rate design for pipeline and storage costs
R-049157 P-042090	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2004	Pennsylvania Office of Small Business Advocate	Cash receipts reconciliation clause
R-049108	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2004	Pennsylvania Office of Small Business Advocate	Uncollectible cost responsibility for standby charges
Application 1306819	Alberta Energy and Utilities Board	ENMAX Power Corporation	January 2004	Calgary Industrial Group Calgary Building Owners	T&D cost allocation, rate design, ratepayer equity funding
R-3492-2002 Phase 2	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2003	AQCIE, CIFQ	Rate policy, cross-subsidization
R-038168	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	July 2003	Pennsylvania Office of Small Business Advocate	Cost allocation, deficiency assignment, rate design, pension cost reconciliation, rate of return
R-3492-2002 Phase 1	Régie de l'Énergie, Québec	Hydro Québec Distribution	January 2003	AQCIE, AIFQ	Cost allocation; maintenance of historical cross-subsidization
M-021612	Pennsylvania Public Utility Commission	Philadelphia Gas Works	September 2002	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, cost allocation, rate unbundling
R-027385	Pennsylvania Public Utility Commission	PG Energy (Southern Union)	July 2002	Pennsylvania Office of Small Business Advocate	Purchased gas cost incentive mechanisms.

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Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
1250932	Alberta Energy and Utilities Board	Aquila Networks Canada (Alberta) Ltd.	July 2002	Senior Petroleum Producers Association	Distribution plant and cost allocation, rate design.
R-027204	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2002	Pennsylvania Office of Small Business Advocate	Purchased gas cost incentive mechanisms, rate design
R-3477-2001	Régie de l'Énergie, Québec	Hydro Québec Distribution	May 2002	AQCIE, AIFQ	Classification/allocation of generation costs, subject to constant unit cost constraint.
1248859	Alberta Energy and Utilities Board	ESBI Alberta Limited	March 2002	IPPSA	Transmission congestion management principles
R-016378	Pennsylvania Public Utility Commission	Philadelphia Gas Works	August 2001	Pennsylvania Office of Small Business Advocate	Cost of gas: commodity price forecasting
R-016179	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2001	Pennsylvania Office of Small Business Advocate	Recovery of CAP costs: PGC treatment of pipeline credits
R-005277	Pennsylvania Public Utility Commission	PFG Gas Inc. and North Penn Gas Company	November 2000	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design.
R-3443-2000	Régie de l'Énergie, Québec	Société en commandite Gaz Métropolitain	November 2000	Industrial Gas Users Association (ACIG)	Tariff unbundling
990005	Alberta Energy and Utilities Board	ESBI Alberta Limited	November 2000	IPPSA	Location-based credits for transmission rates
R-005119	Pennsylvania Public Utility Commission	PG Energy (Southern Union)	July 2000	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, weather normalization
R-994788	Pennsylvania Public Utility Commission	PFG Gas, Inc. and North Penn Gas Company	February 2000	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design
R-994785	Pennsylvania Public Utility Commission	National Fuel Gas Distribution Corp.	December 1999	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design

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EXPERT TESTIMONY SUBMITTED IN UTILITY REGULATORY PROCEEDINGS

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
R-994783	Pennsylvania Public Utility Commission	PG Energy, Inc.	November 1999	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design
99005	Alberta Energy and Utilities Board	ESBI Alberta Limited (Transmission Administrator)	September 1999	IPPSA	Transmission tariff cost allocation, rate design, industry restructuring
RE95080	Alberta Energy and Utilities Board	Alberta Power Limited	December 1998	Independent Power Producers Society of Alberta and SPPA	Electric industry restructuring, rate unbundling, cost allocation and rate design.
RE95081	Alberta Energy and Utilities Board	TransAlta Utilities Corporation	November 1998	IPPSA and Senior Petroleum Producers Assn.	Industry restructuring, cost allocation, rate design.
Expansion Feasibility Test	Public Utilities Board of Manitoba	Centra Gas Manitoba	August 1998	Simplot Canada Limited	Expansion feasibility and customer contribution methodology
R-984280	Pennsylvania Public Utility Commission	PG Energy, Inc.	August 1998	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue deficiency assignment, rate design
EO97070455	New Jersey Board of Public Utilities	Atlantic City Electric Company	February 1998	New Jersey Board of Public Utilities	Industry restructuring, audit of unbundled rates
R-973981	Pennsylvania Public Utility Commission	Allegheny Power (West Penn Power)	January 1998	Pennsylvania Office of Small Business Advocate	Industry restructuring, cost unbunding, cost allocation, and rate design.
R-973954	Pennsylvania Public Utility Commission	Pennsylvania Power & Light	August 1997	Pennsylvania Office of Small Business Advocate	Restructuring, stranded costs, market price forecasting, cost allocation, and rate design.
1996 Electric Utility Tariff Applications	Alberta Energy & Utilities Board	TransAlta Utilities, Alberta Power Edmonton Power, Grid Company of Alberta	October 1996	Independent Power Producers Society of Alberta (IPPSA)	Industry restructuring; transmission cost allocation and rate design.
R-963612	Pennsylvania Public Utility Commission	PG Energy, Inc.	October 1996	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and rebuttal.

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EXPERT TESTIMONY SUBMITTED IN UTILITY REGULATORY PROCEEDINGS

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
R-953444	Pennsylvania Public Utility Commission	Trigen-Philadelphia Energy Corp.	November 1995	Pennsylvania Office of Small Business Advocate	Steam energy cost rate -- direct and rebuttal.
R-953406	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	October 1995	Pennsylvania Office of Small Business Advocate	Weather normalization, cost allocation and rate design.
R-953297	Pennsylvania Public Utility Commission	UGI Utilities, Inc. (Gas Division)	May 1995	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and surrebuttal.
R-943271	Pennsylvania Public Utility Commission	Pennsylvania Power & Light	April/May 1995	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and rebuttal
EBRO 488	Ontario Energy Board	Natural Resource Gas Limited	November 1994	Natural Resource Gas Limited	Customer classification, cost allocation and rate design.
RE92071	Alberta Public Utilities Board	Alberta Power Limited	November 1994	Independent Power Producers Society of Alberta	Cost allocation and rate design for export transmission service.
R-942986	Pennsylvania Public Utility Commission	West Penn Power Company	August 1994	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design.
R-932862	Pennsylvania Public Utility Commission	UGI Utilities, Inc. (Electric Division)	March 1994	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct, rebuttal and surrebuttal.
EBRO 485, and Generic Direct Purchase Hearings	Ontario Energy Board	Consumers' Gas Company, Ltd.	August 1993, September 1993.	Canadian Independent Gas Marketing Association	Classification and allocation of marketing and administrative costs.
Hearings for Cost of Service and Rate Design	Nova Scotia Utility and Review Board	Nova Scotia Power, Inc.	May 1993	Bowater Mersey Paper Company, Ltd.	Classification of bulk power costs, rate design for interruptible service and other rate design issues.

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EXPERT TESTIMONY SUBMITTED IN UTILITY REGULATORY PROCEEDINGS

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
Generic Hearing #4	Board of Commissioners of Public Utilities, Province of New Brunswick	New Brunswick Power Corporation	November 1991	Large Power Users Group	Review of cost allocation and rate design.
EBRO-473	Ontario Energy Board	Consumers' Gas Company, Ltd.	October 1991	Ontario Energy Board Staff	Cost allocation and rate design
EBRO-470	Ontario Energy Board	Union Gas, Ltd.	February 1991	Ontario Energy Board Staff	Cost allocation and rate design; evaluation of load shifting study.
Rate Area Boundaries Hearings	Prince Edward Island Public Utilities Commission	Maritime Electric Co., Ltd.	February 1991	Prince Edward Island Department of Energy and Forestry	Customer classification by geographical area.
EBRO-467	Ontario Energy Board	Centra Gas, Ltd.	January 1991	Ontario Energy Board Staff	Cost allocation and rate design for technology, cogen and bypass.
Arbitration Hearings	Arbitrator	ARINC, Inc.	July 1990	ARINC Inc.	Cost allocation and rate design for aircraft to ground data communications service.
EBRO-462	Ontario Energy Board	Union Gas, Ltd.	January 1990	Ontario Energy Board Staff	Seasonal cost allocation study, and allocation of costs to export markets.
NSPC-857	Nova Scotia Board of Commissioners of Public Utilities	Nova Scotia Power Corp.	February 1989	Interruptible industrial customers	Cost allocation and rate design of interruptible electric service.

August 2006

EXHIBIT IEc-2

REFERENCED INTERROGATORY RESPONSES

OSBA-I-7

OSBA I-29

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OSBA SET I INTERROGATORIES

7. Reference Statement No. 8, pension and OPEB costs:
   a. Please provide copies of the referenced Mercer reports for both pension and OPEB costs.
   b. Please provide the detailed assumptions used by Mercer to derive expected returns on fund assets for both plans.

Response

a. Refer to Exhibit No. 4 Schedule 6 for the pension report and Exhibit No. 4 Schedule 7 for the OPEB report.

b. Refer to the attached letter from Mercer.

MERCER
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Rochester, NY 14604-2707
585 325 2870 Fax 585 325 2091
www.mercerHR.com

August 15, 2006

Mr. David P. Bauer
National Fuel Gas Company
6363 Main Street
Williamsville, New York 14221

Subject:
PA Rate Case

Dear Dave:

As requested, this letter provides the basis for the assumed rate of investment return of 8.25% per annum, net of investment expenses, on which our actuarial valuation report as of July 1, 2005 for National Fuel Gas Company's qualified retirement plan for the plan year ending June 30, 2006 and the taxable year ending September 30, 2005 is based.

The actual asset allocation of National Fuel Gas Company's qualified retirement plan assets as of June 30, 2005 and asset class return, variance and correlation assumptions developed by Mercer Investment Consulting (MIC) as of April 2005 were used to determine the assumed rate of investment return of 8.25% per annum.

The process followed to select the investment return assumption, which is the same process as called for in Actuarial Standard of Practice Number 27, was as follows:

- Identify components (inflation, real return and risk premium) of the investment return assumption and evaluate relevant data
- Develop a best-estimate range of anticipated actual results compounded over the measurement period, reflecting measurement-specific factors
- Further evaluate measurement-specific factors and select a point within the best-estimate range.

Mercer's proprietary *Portfolio Return Calculator* was used to construct a best-estimate range of returns. Asset class return, variance and correlation assumptions developed by MIC and the actual percentage distribution of National Fuel Gas Company's qualified retirement plan assets as of June 30, 2005 by asset class were input into the Calculator. Using this information, the Portfolio Return Calculator produced a gross expected return and distribution of possible returns without any adjustment for expenses. (Note that since the Portfolio Return Calculator takes into account correlation between asset classes over the projection horizon, the overall assumed portfolio return is not simply equal to National Fuel Gas Company's current asset allocation

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percentages multiplied by the assumed compound rate of return for each asset class.) Expenses were then subtracted from the gross expected returns to produce the final net return. The annual expense assumption was assumed to be 0.20% of plan assets. This assumption includes investment management, trading expenses and trustee fees and is the same for both the active and passively managed portfolios. Alpha for active management was assumed to be exactly offset by the increase in investment expenses associated with such active management.

The asset class return, variance and correlation assumptions were developed by MIC as of April 2005. These assumptions are attached. These asset class return assumptions are gross forward-looking returns and were not developed by an examination of historical returns. The April 2005 Treasury yield curve was used as the starting point for developing these assumptions. Corporate bond spreads and equity risk premia, based on market conditions, were added to develop the return expectations for each asset class. The volatility and correlation assumptions are also forward looking; they take into account historical relationships, but were adjusted to reflect expected capital market trends.

The Calculator produced both the expected return and the distribution of possible returns (at every fifth percentile) for National Fuel Gas Company's qualified retirement plan asset portfolio. The 25th and 75th percentiles that resulted from the model for a 20-year projection horizon were 5.32% and 9.45%, respectively. These constitute the best-estimate range of reasonable returns for the portfolio that can be used in actuarial calculations.

We selected 8.25% as the investment return assumption, which was between the 60th and the 65th percentile of the reasonable range of returns.

Please let me know if you have any further questions about how the rate of investment return was selected.

Sincerely,

Kathleen P. Lamb, F.S.A.

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Mercer Standard Percentile Approach

Asset Allocation of Portfolio

Specified By Consultant

Name of Client: National Fuel Gas

	Percentage Allocation
Domestic Equity	
Domestic Equity-All Cap	69.0%
Domestic Equity-Large Cap	0.0%
Domestic Equity-Mid Cap	0.0%
Domestic Equity-Small Cap	0.0%
Domestic Equity-Micro Cap	0.0%
Company Stock-Large	0.0%
Company Stock-Small	0.0%
Private Equity	0.0%
Hedge Funds - Mkt Neutral	0.0%
Hedge Funds - Aggressive	0.0%
International Equity	
International Equity-Unhedged	0.0%
International Equity-Hedged	0.0%
International Eq-Emerging Mkts	0.0%
International Eq-Small Cap	0.0%
Global Equity x-U.S.	0.0%
Global Equity	0.0%
Fixed Income	
Fixed Income-Gov/Corp	0.0%
Fixed Income-Aggregate	22.0%
Fixed Income-Short Gov/Corp	0.0%
Fixed Income-Intermediate G/C	0.0%
Fixed Income-Long G/C	0.0%
Fixed Income-Very Long Bonds	0.0%
Fixed Income-Government	0.0%
Fixed Income-Corporate/Credit	0.0%
Fixed Income-Mortgages	0.0%
Fixed Income-High Yield	0.0%
Fixed Income-Muni Bonds	0.0%
Inflation-Indexed Bonds	0.0%
Cash	3.0%
Convertibles	0.0%
GICs	0.0%
International FixInc-Unhedged	0.0%
International FixInc-Hedged	0.0%
Broad International-Unhedged	0.0%
Emerging Market Debt	0.0%
Real Estate	6.0%
TOTAL	100.0%

Mercer Standard Percentile Approach

Asset Class Return Assumptions

Name of Client:	National Fuel Gas
Source of Return Data:	Mercer Investment Consulting
Date of Return Data:	April 2005
Annual Expense:	0.20%

	Compound Annual Returns	Annual Arithmetic Returns	Standard Deviation of Annual Returns
Domestic Equity			
Domestic Equity-All Cap	8.16%	9.70%	18.6%
Domestic Equity-Large Cap	8.05%	9.50%	18.0%
Domestic Equity-Mid Cap	8.23%	10.20%	21.1%
Domestic Equity-Small Cap	8.38%	10.90%	24.0%
Domestic Equity-Micro Cap	8.76%	12.30%	28.8%
Company Stock-Large	6.10%	9.50%	32.0%
Company Stock-Small	3.71%	10.90%	42.0%
Private Equity	9.38%	14.00%	33.5%
Hedge Funds - Mkt Neutral	6.10%	6.40%	8.0%
Hedge Funds - Aggressive	7.04%	7.70%	12.0%
International Equity			
International Equity-Unhedged	8.19%	10.30%	21.9%
International Equity-Hedged	8.14%	10.00%	20.5%
International Eq-Emerging Mkts	8.55%	11.90%	28.0%
International Eq-Small Cap	8.38%	11.30%	26.0%
Global Equity x-U.S.	8.36%	10.40%	21.5%
Global Equity	0.00%	0.00%	0.0%
Fixed Income			
Fixed Income-Gov/Corp	5.02%	5.20%	6.2%
Fixed Income-Aggregate	5.13%	5.30%	6.0%
Fixed Income-Short Gov/Corp	4.06%	4.10%	3.0%
Fixed Income-Intermediate G/C	4.70%	4.80%	4.5%
Fixed Income-Long G/C	5.43%	6.00%	11.0%
Fixed Income-Very Long Bonds	5.31%	6.80%	18.0%
Fixed Income-Government	4.80%	5.00%	6.5%
Fixed Income-Corporate/Credit	5.50%	5.70%	8.5%
Fixed Income-Mortgages	5.41%	5.60%	6.3%
Fixed Income-High Yield	5.73%	6.40%	12.0%
Fixed Income-Muni Bonds	3.97%	4.30%	8.3%
Inflation-Indexed Bonds	4.20%	4.30%	4.6%
Cash	3.29%	3.30%	1.3%
Convertibles	5.86%	6.70%	13.5%
GICs	4.46%	4.50%	3.0%
International FixInc-Unhedged	4.62%	5.30%	12.0%
International FixInc-Hedged	4.63%	4.80%	8.0%
Broad International-Unhedged	4.82%	5.60%	12.0%
Emerging Market Debt	5.88%	7.20%	17.0%
Real Estate	7.27%	8.10%	13.5%

Note: Compound Returns reflect expected volatility and are, therefore, less than Simple Arithmetic Average Returns.

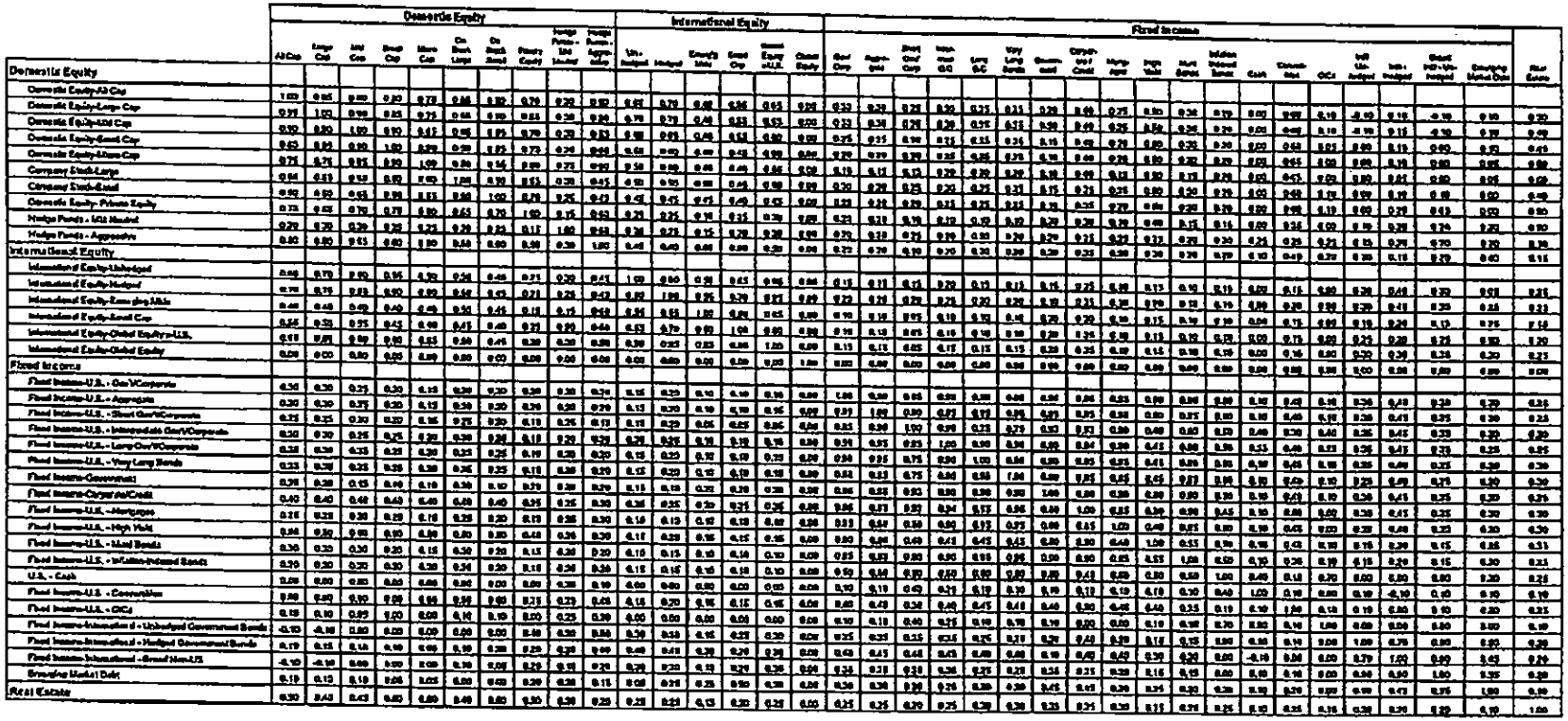
Example: If Year 1 Return = 5% and Year 2 Return = 15%, then Annual Arithmetic Return = 10.00% and Compound Annual Return = 9.54%

Mercer Standard Percentile Approach

Asset Class Correlations

Correlations of Annual Returns

Name of Client: National Fuel Gas
Data Source: Mercer Investment Consulting
Data Date: April 2005



NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OSBA INTERROGATORIES

Q. Reference Exhibit NFG 2-37, page 6:
a. Please state the year(s) to which these months apply.
b. Please explain how these values were derived from the forecast shown in Exhibit 110.

A. a. The volumes are included in the twelve months ended January 2007.
b. Please see Page 2.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
SUMMARY REVENUE MONTH VOLUMES - TME JANUARY 2007

		Feb 05	Mar 05	Apr 05	May 05	Jun 05	Jul 05	Aug 05	Sep 05	Oct 05	Nov 05	Dec 05	Jan 06	Total
Residential E	A1	3,196,719	2,768,682	2,072,997	1,169,471	562,429	344,638	329,318	381,013	699,299	1,332,736	2,422,554	3,307,304	16,587,360
LIRA	A2	195,147	168,871	125,720	71,472	34,641	21,315	20,405	23,640	43,324	82,069	148,618	204,149	1,139,371
Residential Non E	A3	10,057	8,919	7,127	3,837	1,203	639	224	224	726	2,351	5,965	8,881	50,153
Residential Non E SATC	A4	4,730	3,894	3,132	1,231	1,653	71	71	413	375	1,746	3,359	4,593	25,268
		3,406,653	2,950,566	2,208,976	1,246,011	599,926	366,663	350,018	405,290	743,724	1,418,902	2,580,496	3,524,927	19,802,152
Small Comm LE 250	B1	163,495	141,527	103,815	52,704	23,288	18,340	15,721	23,253	34,811	59,858	111,736	170,614	919,162
Small Comm LE 250 Non E	B2	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Comm LE 250 SATC	B3	83	68	58	31	30	18	17	18	22	37	60	79	521
		163,578	141,595	103,873	52,735	23,318	18,358	15,738	23,271	34,833	59,895	111,796	170,693	919,683
Small Comm GT 250	C1	298,058	258,010	189,260	96,062	42,456	33,435	28,660	42,391	63,462	109,123	203,699	311,037	1,675,673
Small Comm GT 250 Non E	C2	4,911	4,231	3,818	2,672	1,731	1,198	1,198	1,198	1,210	2,117	3,251	4,225	31,760
Small Comm GT 250 SATC	C3	1,798	1,475	1,253	682	655	396	370	387	476	794	1,291	1,713	11,270
		304,767	263,716	194,331	99,416	44,842	35,029	30,228	43,976	65,148	112,034	208,241	316,975	1,718,703
Large Commercial	D1	251,104	217,365	159,445	80,946	35,768	28,168	24,145	35,713	53,465	91,933	171,610	262,038	1,411,700
Large Commercial Non E MMT Intra	D2	260,253	224,224	202,364	141,625	91,745	63,533	63,533	63,533	64,149	112,184	172,298	223,931	1,683,372
Large Commercial Non E MMT Inter	D3	44,995	38,766	34,987	24,486	15,862	10,984	10,984	10,984	11,091	19,395	29,789	38,715	281,038
Large Commercial Non E DMT Intra	D4	68,504	59,021	53,267	37,279	24,149	16,723	16,723	16,723	16,885	29,529	45,353	58,944	443,100
Large Commercial Non E DMT Inter	D5	2,780	2,395	2,162	1,513	980	679	679	679	685	1,198	1,841	2,392	17,983
Large Commercial Load Balancing	D6	0	0	0	322	402	876	1,157	1,100	709	267	143	0	4,976
Large Commercial SATC	D7	5,677	4,657	3,956	2,090	2,067	1,251	1,170	1,224	1,505	2,506	4,078	5,408	35,589
		633,313	548,428	456,181	288,261	170,973	122,214	118,391	129,956	148,489	257,012	425,112	591,428	3,887,758
Commercial		1,101,658	951,739	754,385	440,412	239,133	175,601	164,357	197,203	248,470	428,941	745,149	1,079,096	6,526,144
Small PA LE 250	E1	6,980	6,409	5,255	1,554	872	1,181	917	1,051	3,144	4,223	5,670	10,307	47,563
Small PA GT 250	F1	17,716	16,261	13,320	3,866	2,146	2,935	2,261	2,603	7,936	10,687	14,377	26,198	120,326
Small PA GT 250 Non E	F2	1,649	1,398	1,214	788	393	202	200	198	198	575	1,043	1,382	9,240
Small PA GT 250 SATC	F3	273	176	193	58	86	9	9	9	14	78	164	215	1,284
		19,638	17,835	14,727	4,732	2,625	3,146	2,470	2,810	8,150	11,340	15,584	27,795	130,852
Large PA	G1	39,542	36,294	29,731	8,674	4,789	6,550	5,047	5,810	17,717	23,854	32,090	58,473	268,571
Large PA Non E MMT Intra	G2	315,340	267,354	232,269	150,711	75,198	38,734	38,318	37,901	37,901	110,026	199,490	264,316	1,767,558
Large PA Non E MMT Inter	G3	65,435	55,478	48,197	31,273	15,604	8,038	7,951	7,865	7,865	22,831	41,395	54,847	366,779
Large PA SATC	G4	1,113	716	784	237	348	37	37	37	57	317	666	873	5,222
		421,430	359,842	310,981	190,895	95,939	53,359	51,353	51,613	63,540	157,028	273,641	378,509	2,408,130
Public Authority		448,046	384,086	330,963	197,181	99,436	57,686	54,740	55,474	74,834	172,591	294,895	416,611	2,586,545
SVIS	H1	18,023	12,539	9,025	3,821	1,287	832	794	969	1,299	3,588	9,481	15,934	77,572
SVIS MMT Intra	H2	475	330	238	101	34	22	21	26	34	95	249	420	2,045
		18,498	12,869	9,263	3,922	1,321	854	815	995	1,333	3,683	9,710	16,354	79,617
IVIS	I1	40,409	34,873	32,805	21,280	9,023	7,695	7,040	8,171	7,879	10,431	12,881	33,347	225,834
IVIS MMT Intra	I2	276,736	238,815	224,654	145,730	114,393	97,551	89,234	103,595	99,915	132,230	163,296	228,369	1,914,518
IVIS MMT Inter	I3	71,513	61,713	58,054	37,659	29,561	25,209	23,059	28,771	25,820	34,170	42,198	59,014	494,741
IVIS MMT Intra Flex	I4	0	0	0	0	0	0	0	0	0	0	0	0	0
IVIS MMT Inter Flex	I5	0	0	0	0	0	0	0	0	0	0	0	0	0
IVIS DMT Intra	I6	67,345	58,116	54,670	35,464	27,838	23,739	21,715	25,210	24,315	32,179	39,739	55,574	465,904
IVIS DMT Inter	I7	4,575	3,948	3,714	2,409	1,891	1,613	1,475	1,713	1,652	2,186	2,699	3,775	31,650
IVIS Load Balancing (Trans)	I8	0	0	0	0	7,681	6,550	5,991	6,956	6,709	8,878	10,964	0	53,729
IVIS SATC	I9	747	645	607	394	309	263	241	280	270	357	441	617	5,171
		461,325	398,110	374,504	242,936	190,696	162,620	148,755	172,696	166,560	220,431	272,218	380,696	3,191,547
LVIS MMT Intra	J1	58,890	51,222	50,404	37,942	28,653	27,738	26,049	26,648	28,857	36,413	42,431	51,408	484,753
LVIS MMT Inter	J2	28,024	24,197	20,380	14,792	9,287	7,247	6,914	7,127	8,010	11,804	14,173	20,452	172,407
LVIS MMT Intra Flex	J3	13,654	10,409	8,243	8,601	8,783	12,685	9,627	12,560	12,892	8,950	11,593	10,002	127,999
LVIS MMT Inter Flex	J4	2,843	2,194	1,761	1,219	901	882	875	900	880	1,103	-1,323	2,116	16,997
LVIS DMT Intra	J5	236,176	227,500	219,484	195,588	173,906	167,883	150,574	154,067	149,080	170,022	177,199	201,877	2,223,338
LVIS DMT Inter	J6	14,305	16,529	16,680	14,649	12,942	12,377	11,054	10,318	10,023	11,652	12,214	13,840	158,581
LVIS DMT Intra Flex	J7	45,708	38,961	40,529	34,864	28,861	28,646	25,857	31,808	29,000	33,911	35,942	40,136	414,223
LVIS DMT Inter Flex	J8	4,983	4,463	4,567	3,830	2,893	2,963	2,237	3,228	3,038	3,891	3,905	4,261	44,057
LVIS Load Balancing (Trans)	J9	0	0	0	4,525	5,694	7,782	9,241	7,729	8,569	6,340	14	0	49,894
		402,685	375,475	362,028	315,810	271,920	268,203	242,428	254,379	250,349	284,086	298,794	344,092	3,870,249
LIS Load Balancing (Retail)	K1	0	0	0	0	0	0	0	0	0	0	0	0	0
LIS MMT Intra	K2	31,558	27,403	24,223	19,666	14,100	14,056	14,993	16,858	16,882	20,600	20,184	24,878	245,401
LIS MMT Inter	K3	1,316	1,142	1,009	818	586	586	624	702	702	859	842	1,036	10,222
LIS DMT Intra	K4	159,604	138,443	132,828	114,222	98,774	97,384	93,670	100,999	100,181	117,065	122,122	126,708	1,402,000
LIS DMT Inter	K5	35,801	32,250	31,682	28,236	25,127	25,629	24,372	24,992	25,764	30,576	32,330	31,242	348,001
LIS DMT Intra Flex	K6	364,951	352,595	365,817	341,488	338,707	324,386	337,639	332,136	324,361	333,919	318,243	350,826	4,085,068
LIS DMT Inter Flex	K7	54,870	53,341	52,733	51,711	51,983	49,068	50,783	49,086	48,761	49,398	48,709	53,737	613,940
		647,900	605,174	608,292	556,141	529,257	511,109	522,081	524,753	516,651	552,417	542,430	588,427	6,704,632
Industrial		1,530,408	1,391,628	1,354,087	1,118,809	993,194	942,786	914,079	952,823	934,893	1,060,617	1,123,152	1,329,569	13,646,045
Total		6,486,767	5,678,019	4,848,411	3,002,413	1,931,689	1,542,736	1,483,194	1,610,790	2,001,921	3,081,051	4,743,692	6,350,203	42,560,886

EXHIBIT IEc-3

TRENDS IN THROUGHPUT PER CUSTOMER

FROM NFGD'S LAST THREE BASE RATES CASES

Exhibit IEc-3
Comparison of Throughput and Customer Forecasts in NFGD Base Rates Cases

	Total	*Residential*	*SC&PA LE 250*	*SC&PA GT 250*	*LC&PA Service*	*SVIS*	*IVIS*	*LVIS*	*LIS*	*Sub-Total C&PA*
Test Year 01/07										
Customers	209,975	193,982	8,974	4,144	2,270	187	366	39	13	15,388
Throughput	42,560,886	19,802,152	967,246	1,849,555	6,295,888	79,617	3,191,547	3,670,249	6,704,632	9,112,689
Mcf/Customer/Year	202.7	102.1	107.8	446.3	2,773.5	425.8	8,720.1	94,108.9	515,740.9	3,328
Reduction from 05/05		-7.8%	-15.1%	-10.4%	-3.8%	-7.2%	1.1%	3.0%	12.4%	-5.2%
Peak Demand	365,252	210,794	10,856	20,642	61,978	439	21,328	15,832	23,383	93,476
Load Factor	31.9%	25.7%	24.4%	24.5%	27.8%	49.7%	41.0%	63.5%	78.6%	26.7%
Usage Rate Decline	2,311,022	1,673,435	171,763	214,436	251,387					637,587
Tail Block Charge		$ 1.95	$ 2.30	$ 1.83	$ 1.19					$ 1.70
Lost Revenue	4,341,131	3,255,834	394,952	391,797	298,548					1,085,296
Test Year 05/05										
Customers	211,582	195,590	9,117	4,018	2,238	189	377	38	15	15,373
Throughput	44,959,373	21,653,607	1,157,159	2,001,235	6,454,979	86,734	3,252,649	3,472,542	6,880,468	9,613,373
Mcf/Customer/Year	212.5	110.7	126.9	498.1	2,884.3	458.9	8,627.7	91,382.7	458,697.9	3,509
Reduction from 2003		-0.7%	-2.4%	-0.1%	1.4%	-10.6%	-4.4%	7.1%	-18.7%	1.1%
Peak Demand	388,803	228,194	12,218	21,013	61,232	1,141	21,938	15,464	27,603	94,463
Load Factor	31.7%	26.0%	25.9%	26.1%	28.9%	20.8%	40.6%	61.5%	68.3%	27.9%
Test Year 09/03										
Customers	216,373	200,020	9,163	4,281	2,288	175	388	43	15	15,732
Throughput	47,862,773	22,305,065	1,191,852	2,133,432	6,505,999	89,863	3,501,606	3,670,531	8,464,425	9,831,283
Mcf/Customer/Year	221.2	111.5	130.1	498.3	2,843.5	513.5	9,024.8	85,361.2	564,295.0	3,472
Peak Demand	415,674	237,565	14,365	26,414	69,856	1,234	21,707	16,943	27,590	110,635
Load Factor	31.5%	25.7%	22.7%	22.1%	25.5%	20.0%	44.2%	59.4%	84.1%	24.3%

Exhibit IEc-3
Implied Elasticities from NFGD Econometric Analyses

	Residential	*Commercial*	*Public Authority*
Coefficients			
Heating Degree Days	0.0150	0.0497	0.1673
Real Price Lagged 10 Months	-1.3110	-8.1433	-33.1403
Trend	-0.1486	-0.2222	0.0000
January 2006 Values -- 12 Month Moving Averages			
Throughput per Customer	101.6	469.3	2040.1
Heating Degree Days	6243	6243	6243
Real Price Lagged 10 Months	11.11	10.79	10.97
Elasticities			
Heating Degree Days	92.5%	66.2%	51.2%
Real Price	-14.3%	-18.7%	-17.8%
Trend (% per Year)	-1.8%	-0.6%	0.0%

EXHIBIT IEc-4

FIRST DOLLAR RELIEF CALCULATIONS

Exhibit IEc-4
Proposed First Dollar Relief for Commercial Customers ($ millions)

	(1) NFGD Avg. Allocated Cost Proposed Rates	(2) Revenues at Present Rates	(3) NFGD Proposed Rate Revenue Increase	(4) NFGD Proposed Total Revenue Increase	(5) NFGD Proposed Class Revenues	(6) Revenue-Cost Ratios at NFGD Proposed Rates	(7) Reduced Cost Basis	(8) FDR for LC&PA and SC&PA GT 250
Residential	100.808	74.938	20.161	20.237	95.175	94.4%	93.137	
SC&PA LE 250	4.871	4.232	1.141	1.145	5.377	110.4%	4.501	(0.530)
SC&PA GT 250	4.730	4.946	1.325	1.330	6.276	132.7%	4.370	(1.330)
LC&PA	11.253	11.703	3.168	3.180	14.883	132.3%	10.397	(3.180)
SVIS	0.235	0.310	(0.000)	(0.000)	0.310	131.8%	0.217	
IVIS	4.077	4.236	0.000	0.000	4.236	103.9%	3.767	
LVIS	3.158	3.076	(0.000)	(0.000)	3.076	97.4%	2.918	
LIS	2.287	2.086	0.000	0.000	2.086	91.2%	2.113	
Total	**131.419**	**105.528**	**25.794**	**25.892**	**131.419**	**100.0%**	**121.42**	**(5.040)**
Non-Commercial	*9.757*	*9.707*	*0.000*	*0.000*	*9.708*	*99.5%*	*9.014*	*0.000*

	(9) NFGD Proposed Increase After FDR	(10) NFGD Proposed Revenues After FDR	(11) Revenue-Cost Ratio After FDR	(12) Proportional Scaleback of Cost Reduction	(13) Increase After FDR and Scaleback	(14) Class Revenues After FDR and Scaleback	(15) Revenue-Cost Ratio after FDR and Scaleback	(16) Percent Revenue Increase
Residential	20.237	95.175	102.2%	(4.814)	15.423	90.362	97.0%	20.6%
SC&PA LE 250	0.615	4.847	107.7%	(0.146)	0.469	4.701	104.4%	11.1%
SC&PA GT 250	0.000	4.946	113.2%	0.000	0.000	4.946	113.2%	0.0%
LC&PA	0.000	11.703	112.6%	0.000	0.000	11.703	112.6%	0.0%
SVIS	(0.000)	0.310	142.6%	0.000	(0.000)	0.310	142.6%	0.0%
IVIS	0.000	4.236	112.5%	(0.000)	0.000	4.236	112.5%	0.0%
LVIS	(0.000)	3.076	105.4%	0.000	(0.000)	3.076	105.4%	0.0%
LIS	0.000	2.086	98.7%	0.000	0.000	2.086	98.7%	0.0%
Total	**20.852**	**126.380**	**104.1%**	**(4.960)**	**15.892**	**121.419**	**100.0%**	**15.1%**
Non-Commercial	*0.000*	*9.708*	*107.7%*	*(0.000)*	*0.000*	*9.708*	*107.7%*	*0.0%*

Notes:
(1) Cost basis is the average of the four NFGD COSSs. Return and income taxes are allocated based on rate base.
(2) Revenues at present rates include rate revenues and other revenues.
(3) NFGD proposed rate increase is based on values in Exhibit 103 Schedule 1-A (non-seasonal) proof of revenues.
(4) NFGD proposed increase in other revenues based on late charge allocation in NFGD COSS "A" and "B."
(5) Sum of columns (2) and (4).
(6) Ratio of column (5) to column (1).
(7) Reduction of $10.00 million in revenue requirement. Costs allocated in proportion to column (1).
(8) FDR is lesser of the NFGD proposed increase and the difference between class R/C ratio and the non-commercial R/C ratio (from column (6)), multiplied by class allocated costs in column (1).
(9) Equals column (4) plus column (8). That is, NFGD proposed increase less FDR.
(10) Equals column (2) plus column (9). That is, present revenues plus increase after FDR (or NFGD proposed revenues less FDR).
(11) Ratio of column (10) to column (1).
(12) Total amount is total reduction from column (7) less FDR from column (8). That amount is allocated in proportion to column (9).
(13) Equals column (9) plus column (12). That is, increase after FDR less proportional scaleback credit.
(14) Equals column (2) plus column (13). That is, present revenues plus increase after FDR and after scaleback.
(15) Ratio of column (14) to column (1).
(16) Increase in column (14) divided by present rates in column (2).

EXHIBIT IEc-5

ELECTRONIC WORKPAPERS OF ROBERT D. KNECHT

1. NFG COSS 06 A.xls
2. NFG COSS 06 B.xls
3. NFG COSS 06 C.xls
4. NFG COSS 06 D.xls
5. NFG COSS 06 E.xls
6. NFG COSS 06 F.xls
7. NFG COSS 06 G.xls
8. NFG COSS 06 H.xls
9. NFG BR06 Load Comparison.xls
10. NFG BR06 RoR Workpapers.xls
11. NFG BR06 FDR Example.xls

Electronic copies of these workpapers will be provided to any party to this proceeding upon request to the OSBA.

OSBA STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-00061493
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	:	

Rebuttal Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Office of Small Business Advocate

Date Served: September 28, 2006

Date Submitted for the Record: _____

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. Introduction and Overview

Q. Please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct testimony earlier in this proceeding, and my qualifications were presented therein.

Q. Please describe the purpose of this rebuttal testimony.

A. I was asked by the Pennsylvania Office of Small Business Advocate ("OSBA") to review and analyze the direct testimony of Mr. Richard Galligan on behalf of the Pennsylvania Office of Consumer Advocate ("OCA") and the direct testimony of Mr. Joseph Kubas on behalf of the Office of Trial Staff ("OTS"), with respect to cost allocation and revenue allocation issues. OSBA also asked me to review Mr. Kubas' proposals for rate design for small business customers.

Q. Please summarize your conclusions regarding the testimony of those witnesses.

A. Mr. Galligan and Mr. Kubas rely on very similar cost allocation methodologies, and yet they develop radically different proposals for allocating the rate increase among the various classes. Both Mr. Galligan and Mr. Kubas rely on a cost allocation methodology that assumes that mains costs are not causally related to the number of customers attached to the distribution system, and that mains costs should be allocated based partly on peak demands and partly on annual throughput volumes.

I respectfully disagree with that methodology, and will very briefly explain the reasons why in this rebuttal testimony. However, the most important point in this proceeding is that the choice of cost allocation methodology is almost irrelevant for revenue allocation. All cost allocation methodologies presented in this case indicate that small business customers already face rates that substantially exceed the cost of providing service to them. In my view, the issue for this case is how to reflect this unanimity of cost allocation results in revenue allocation.

This rebuttal testimony will therefore address the question of how the rate increase should be distributed among the various rate classes, if the cost allocation methodology

endorsed by Messrs. Galligan and Kubas is adopted by the Commission. As I will explain, Mr. Galligan's proposal for assigning the rate increase is wholly inconsistent with the results of his own cost allocation analyses. By way of contrast, Mr. Kubas' proposal is reasonably consistent with the cost allocation study results upon which he relies, and it represents one reasonable approach for this proceeding if his cost allocation methodology is approved. However, Mr. Kubas' proposal involves assigning higher rate increases to some rate classes than those proposed by the Company. Thus, as an alternative to Mr. Kubas' proposal, I develop a "first dollar relief" proposal in this rebuttal testimony, conceptually similar to that in my direct testimony, but based on the assumption that the Commission adopts the Kubas/Galligan cost allocation framework.

Finally, I note that Mr. Kubas' proposal for the customer charge for the LC&PA rate class is substantially inconsistent with every customer cost analysis presented in this proceeding, including his own analysis.

2. Cost Allocation

Q. What cost allocation methodologies do Mr. Kubas and Mr. Galligan rely upon in developing revenue allocation and rate design recommendations?

A. Mr. Kubas does not prepare an independent cost of service study ("COSS"). Instead, he relies explicitly on the methodology used in NFGD's COSS versions "A" (present rates) and "B" (proposed rates). The methodology used in those versions of NFGD's COSS is based on the assumption that there is no customer component to mains costs, and that demand-related costs should be distributed among rate classes using an allocator that is partly based on peak demand and partly based on average annual throughput (the "peak-and-average" or "P&A" allocator).

Mr. Galligan also indicates that he relies on the allocation methodology for mains cost classification and demand cost allocation in NFGD COSS versions "A" and "B," although he develops a separate COSS that assigns demand-related costs to a "lost class."

Q. Your direct testimony indicates that you do not agree with the proposition that mains costs have no customer component. Can you briefly respond to Mr. Galligan's assertions that a customer component is not consistent with cost causation?

A. First, Mr. Galligan argues that a customer component of distribution costs is not consistent with Commission precedent from 1994 (OCA Statement No. 3 page 5). However, I note that in 2004 (at Docket No. R-00049255) the Commission relied primarily on a cost allocation study for PPL Electric that included a customer component of secondary distribution costs, using a minimum system methodology.[1] While that matter was an electric distribution rate case, the conceptual basis for a customer component of electric distribution costs is very similar to that for gas distribution costs, and the arguments in opposition to a customer component for gas mains costs are virtually indistinguishable from those raised in electric rate proceedings. As such, Commission precedent provides sufficient flexibility to recognize a customer component in cost allocation considerations.

Second, Mr. Galligan's argument that NFGD's 2-inch mains minimum-system methodology fails to recognize the load carrying capability of the minimum system (OCA Statement No. 3 page 10) is simply wrong. NFGD does not use a minimum system approach and its customer component is not based on the cost of a 2-inch diameter main. NFGD relies on a zero-intercept approach, in which the customer component of mains costs is based on the cost of a system with zero-diameter pipe. Zero-diameter pipe has no load carrying capability.

Third, Mr. Galligan argues that non-residential customers are located farther apart than residential customers, and therefore the length-related portion of mains costs is not proportional to the number of customers. Mr. Galligan offers no evidence that this assertion is correct in NFGD's service territory, and it is not consistent with the common sense observation that non-residential customers tend to be clustered in commercial areas, while residential customers are more dispersed. The zero-intercept methodology recognizes those economies, while Mr. Galligan's approach does not. It makes little sense to argue, as Mr. Galligan does, that the mains length needed to serve one large commercial customer with a peak daily load of 30 Mcf per day (about average for

[1] Note that the Commission's decision at Docket No. R-0009255 also relied primarily on PPL Electric's peak demand allocator, as preferred over the peak-and-average allocation approach.

NFGD's LC&PA class) is the same as that needed to serve 30 residential or even 30 small commercial customers each with peak day load of 1 Mcf per day.

Fourth, while Mr. Galligan relies on Bonbright's Principles of Public Utility Rates as the authority for rejecting a customer component of costs, other texts recognize a demand-customer split as consistent with established principles, including the American Gas Association's Gas Rate Fundamentals which states:

> *The closer a plant item (e.g., a meter and a service line) is located to a customer, the more that particular item is related to the specific requirements of that customer. Thus, the customer component of the distribution costs reflects the theoretical distribution system that would be needed to serve customers at nominal or minimal load conditions.*[2]

Similarly, NARUC's "Gas Distribution Rate Design Manual" employs a demand-customer split in its illustrative cost of service study. It states:

> *The distribution plant investment in mains may be classified as both demand and customer-related. The customer component was determine[d] as the amount of investment that would be required if all mains were comprised of a theoretical minimum size. . . . The customer component of mains is computed by multiplying the total length of mains . . . by the unit cost of the smallest mains.*[3]

Q. Please explain why you do not agree with Mr. Galligan regarding the use of the P&A allocator for demand-related costs.

A. A natural gas distribution main must be sized to meet peak demands, regardless of whether the customers using that main consume the same volume on every day or consume gas on only one day per year. Mr. Galligan's arguments cannot alter the basic system planning requirements, nor do they explain why cost causation should be ignored.

First, Mr. Galligan argues correctly that there are economies of scale in mains construction, such that the incremental cost of an additional unit of mains capacity is below the average cost. (OCA Statement No. 3 page 18) However, while that argument is correct, it does not justify Mr. Galligan's proposed change in cost allocation. An

[2] Gas Rate Fundamentals, Fourth Edition, American Gas Association, 1987, page 136.

[3] "Gas Distribution Rate Design Manual," NARUC Staff Subcommittee on Gas, June 1989, page 32.

incremental unit of demand from a residential customer costs the same as an incremental unit of demand from an industrial customer, and each contribute the same amount to the need for mains capacity. Mr. Galligan is simply arguing that more of the benefits of the economies of scale should flow to low load factor customer classes and less to higher load factor classes. A peak demand allocator shares that benefit among all rate classes proportionately.

Second, Mr. Galligan argues that because the Company's investment policy is based on revenues generated from a new customer, and because those revenues are based on commodity charges, the cost allocation should also be based on commodity throughput. (OCA Statement No. 3, page 15) Mr. Galligan's logic is backwards, in that he is relying on rate design to justify a cost allocation methodology. NGDCs use commodity charges for distribution rate design for practical reasons, not because they are representative of cost causation. If it were practicable, natural gas distribution companies would recover demand-related costs with a demand charge, not commodity charges. And, if they did so, the revenues generated by a new customer would be based on that customer's peak demand, and the decision as to whether a new customer is attached to the system would also be based on the customer's peak demand. Simply because it is not practical to apply demand charges to small customers does not mean that cost causation should be ignored in a COSS.

Q. Can you comment briefly on Mr. Galligan's COSS with a "lost class," based on reductions in loads since the 1973 to 1979 period?

A. Allocating costs to a class of customers that has left the system, or to load that has declined due to customer conservation, is only reasonable if the costs associated with that load are deemed not to be "used and useful," and will therefore be excluded from the NGDC's allowed revenue requirement. Mr. Galligan makes no such assertion. It is a fundamental principle of embedded cost allocation studies that all reasonably incurred used-and-useful costs are allocated among rate classes.

Moreover, even if such a methodology were approved, Mr. Galligan's COSS will substantially overstate the costs associated with the "lost class." Mr. Galligan's COSS allocates all costs to all classes, including the capital costs incurred by NFGD *after* the

load had disappeared. In effect, Mr. Galligan is assigning the higher return and depreciation costs associated with relatively new plant to load that departed years ago. If Mr. Galligan's overall approach is accepted by the Commission, it would be much more reasonable to identify the specific plant assets that were in place in the 1973-1979 period, and then identify the costs in NFGD's current revenue requirement associated with those assets. Only those costs should be allocated to the lost class. All costs incurred since the load departed should be assigned to the current load. Furthermore, since these "pre-departure" assets will be significantly depreciated by 2006, it is unlikely that Mr. Galligan's COSS methodology will be materially different than NFGD's approach.

3. Revenue Allocation Proposals

Q. Can you provide a comparison of the results of the various cost allocation methodologies presented in this proceeding?

A. Table IEc-R1 below presents a comparison of class rates of return (at present rates) under the various methodologies. Note that, for Mr. Galligan's OCA COSS, I reported the system average rate of return exclusive of Mr. Galligan's lost class. If the lost class were included, the OCA COSS would have a system average return of 4.5 percent. The comparison in Table IEc-R1 is more relevant, however, because it compares rates of return only among rate classes who are actually paying utility rates to NFGD.

Table IEc-R1
Comparison of COSS Results
Class Rate of Return at Present Rates

	NFGD Average/OSBA	*NFGD "A"/OTS*	*OCA*
Residential	2.6%	3.4%	6.1%
SC&PA LE 250	6.1%	7.0%	11.0%
SC&PA GT 250	11.0%	9.4%	17.2%
LC&PA	11.5%	7.8%	17.7%
SVIS	19.3%	16.2%	24.1%
IVIS	12.1%	6.2%	17.2%
LVIS	11.9%	2.7%	13.3%
LIS	7.4%	4.8%	10.4%
Total	**4.5%**	**4.5%**	**8.5%**

Note:
1) OCA "Total" excludes the "lost class."
2) Shaded items indicate a return below system average.

All three methodologies show a reasonably similar pattern: the residential class provides a rate of return below system average, while the small business classes (SC&PA, LC&PA and SVIS) all provide a return substantially in excess of system average. Under the NFGD "A" methodology, the industrial classes provide a return that is either slightly above or slightly below system average, whereas in the average of the NFGD methods and in the OCA COSS, the industrial classes provide a return that is well in excess of system average.

All the COSS methodologies indicate that small businesses should be assigned rate increases below system average. Mr. Kubas and I make such a recommendation, while NFGD and Mr. Galligan do not.

Q. Can you summarize the various proposals for assigning the rate increase among the rate classes?

A. Exhibit IEc-R1 attached to this testimony shows the proposed rate increases from the various parties in three dimensions: the dollar value of the increase, the percentage of the overall rate increase assigned to each rate class, and the percent increase in average distribution rates for the class.

By way of explanation, it is not completely clear to me what Mr. Galligan's revenue allocation proposal is. At page 3 of his testimony, Mr. Galligan indicates that he supports the revenue allocation proposed by the Company. At page 27 of his testimony, he advocates an across-the-board revenue allocation. As NFGD did not propose any rate increase for the SVIS, IVIS, LVIS or LIS rate classes, an across-the-board rate increase is not consistent with the Company's proposal. I have therefore identified both proposals with OCA in Exhibit IEc-R1.

Q. Is Mr. Galligan's revenue allocation consistent with his COSS?

A. No it is not. Mr. Galligan's COSS indicates that all "real" rate classes except for the residential class are providing a return well in excess of system average, and yet he proposes an across-the-board increase. On its face, Mr. Galligan's proposal is inequitable, in that it ignores the differences in the results of the cost allocation study.

Moreover, Mr. Galligan argues that all rate classes, including the residential class, are providing a return in excess of the system average, and therefore he concludes that an across-the-board increase is appropriate. Mr. Galligan provides no explanation as to why a rate class that exhibits a rate of return of 24.1 percent, such as the SVIS class, should be assigned the same rate increase as a class exhibiting a 6.1 percent rate of return, such as the residential class. In addition, Mr. Galligan's COSS also indicates that the present rate of return for almost all of the rate classes exceeds not only NFGD's present system average rate of return but also its proposed system average rate of return of 9.5 percent. The only rate class in Mr. Galligan's COSS that does not produce a 9.5 percent rate of return (or higher) at present rates is the residential class. Thus, Mr. Galligan's logic leads to the conclusion that the only rate class that should be assigned a rate increase is the residential class.

Q. Is Mr. Kubas' revenue allocation proposal consistent with the COSS upon which he relies?

A. For the most part, it is. Mr. Kubas proposes to assign the largest rate increase to the residential class, which exhibits a below-system-average rate of return. He proposes to assign below system-average rate increases to the small business classes, which exhibit above-system-average rates of return at present rates. Within the small business customer group, he proposes to assign a minimal rate increase to the SC&PA GT250 and SVIS customers, who exhibit the highest class rates of return at present rates in his COSS.

The only anomaly in Mr. Kubas' proposal is to assign a below system-average rate increase to the LVIS class, which exhibits a below-average rate of return at present rates in his COSS. Mr. Kubas appears to base that proposal on the principle of gradualism (OTS Statement No. 3 at page 48).[4] I do not agree that the principle of gradualism can

[4] I note that Mr. Kubas reports percentage rate increases on a total bill basis, which implies smaller percentage rate increases for sales customers than transportation customers, which may explain his concern about gradualism. However, the total-bill basis is an inappropriate comparison of apples and oranges, because it ignores the fact that transportation customers must also incur gas costs. Moreover, this proceeding is a base rates case for distribution costs -- gas supply costs are not relevant to this proceeding. Finally, an unbundled comparison is consistent with the decision of the Commonwealth Court in the PPL Electric base rates case (Lloyd v. Pennsylvania Public Utility Commission, Nos. 137 CD 2005, 144 CD 2005, 275 CD 2005, and 884 CD 2005 (Opinion and Order filed August 4, 2006), page 16).

justify a below-average rate increase for a particular class, while other classes face a larger rate increase. However, competitive conditions may also be a concern for the customers within this rate class.

In addition, Mr. Kubas proposes that no increase be assigned to the LIS class, on the basis that the LIS customers generally have competitive or bypass alternatives.

Thus, while I do not agree with the COSS methodology used by Mr. Kubas, if that methodology is adopted by the Commission, Mr. Kubas' revenue allocation proposal represents a reasonable approach.

Q. In your direct testimony, you presented a first dollar relief proposal for assigning the rate increase among rate classes, in the event that the Commission reduces NFGD's proposed overall increase. You based that proposal on an average of the four NFGD COSSs. Can you provide a version of that proposal, using the COSS methodology used by Mr. Kubas and conceptually supported by Mr. Galligan?

A. Yes. Exhibit IEc-2R presents a first dollar relief proposal, based on NFGD COSS methodology "B."

In preparing that exhibit, I generally followed the algorithm that I described in my direct testimony for first dollar relief. However, in contrast to an average of the four NFGD COSSs (which I used in my direct testimony), COSS B assigns less cost to the residential rate class, and therefore the rate of return for that class at NFGD's proposed rates is higher relative to the industrial rate classes. To recognize that difference, I modified my algorithm to set the amount of first dollar relief for the C&PA classes such that the revenue-cost ratio from those classes is set equal to that of the residential rate class.[5] That is, the first dollar relief would put the small business classes on a par with the residential class, to the extent possible without assigning a rate decrease.

As shown in Exhibit IEc-R2, this approach results in first dollar relief of $4.3 million for the C&PA classes, compared to $5.0 million in my direct testimony. This alternative proposal also results in a somewhat lower rate increase for the SC&PA LE250 rate class

[5] If I followed the exact methodology in my direct testimony, no rate class other than the residential class would be assigned a rate increase.

than in my 4-COSS proposal, because NFGD COSS "B" allocates less costs to small, low load-factor customers. For the same reasons, it also assigns a rate increase to the LC&PA class (which my 4-COSS proposal did not). If the Commission adopts the OTS COSS methodology, this approach represents an alternative approach to that offered by Mr. Kubas. Because it is a first dollar relief proposal, it does not involve assigning rate increases to any class that are greater than those proposed by the Company.

4. Rate Design for Small Business Customers

Q. Do you have any major disagreements with Mr. Kubas' rate design proposals for the SC&PA customer classes?

A. No I do not. My rate design recommendations and the supporting rationale are presented in my direct testimony. For the SC&PA LE250 rate class, Mr. Kubas offers an alternative approach to recovering the class revenue requirement, based on increasing the first block charge. However, as I described in my direct testimony, increasing the rate differential between the first and second block charges for this class will implicitly provide for recovery of customer-related costs. As such, Mr. Kubas' proposal is conceptually similar to the recommendations in my direct testimony to increase the customer charge -- both proposals have the effect of imposing more costs on low usage months.

For the SC&PA GT250 class, Mr. Kubas proposes no distribution increase. If his revenue allocation proposal is adopted, I agree that no change in the tariff charges would be appropriate.

Q. Do you agree with Mr. Kubas' proposal for rate design for the LC&PA class?

A. I agree with Mr. Kubas' proposal to assign uniform increases to sales and transportation commodity charges within the LC&PA class, for the reasons presented in my direct testimony. However, I do not agree with Mr. Kubas' proposal for the LC&PA customer charge.

Mr. Kubas proposes to increase the customer charge for the LC&PA class from $121.01 per month to $143.75 per month. In so doing, he violates the principle in his testimony, "In my opinion, customer charges should be based on cost." (OCA Statement No. 3, page 23) By his analysis, customer costs for the LC&PA class are $36.60 per month,

and yet he proposes a customer charge that is nearly four times that. (If that approach were applied to the residential class, the customer charge would be over $55 per month.) Thus, Mr. Kubas' proposal for LC&PA is hopelessly inconsistent with his recommendations for the other rate classes.

It should be recognized that Mr. Kubas' definition of customer costs includes only "direct" customer costs, and that not all analysts agree that it is appropriate to include only direct customer costs in the customer charge, particularly for commercial rate classes. However, even if all customer costs are included in the customer cost analysis, and an average of all of NFGD's four COSS methodologies is used, the monthly allocated customer cost for LC&PA customers is under $77 per month, far below the current charge of $121. No matter which analysis is used, the customer charge already far exceeds any analysis of customer costs. In effect, small customers are already subsidizing larger customers within that class to a significant degree, and Mr. Kubas' proposal will only make that problem worse.

For the reasons presented in my direct testimony, there is no cost basis for increasing the customer charge for these customers.[6] To the extent this class is assigned a rate increase at all, it should apply to commodity charges only.

Q. Does this conclude your rebuttal testimony?

A. Yes it does.

[6] Note that I made conceptually similar arguments in NFGD's last proceeding at Docket No. R-00049656, and in NFGD's 2003 base rates proceeding at Docket No. R-00038168. In both of those proceedings, NFGD proposed to increase the LC&PA customer charge above $121.01 per month, but it did not do so in the current proceeding.

EXHIBIT IEc-R1

COMPARISON OF REVENUE ALLOCATION PROPOSALS

Exhibit IEc-R1
Comparison of Revenue Allocation Proposals

	NFGD Avg. Alloc. Cost Prop. Rates	Revenues at Present Rates	NFGD/OCA Proposed Increase	OCA Across-the-Board Increase	OTS Increase	OSBA Increase -- Scaled	Simple Average of Proposals
Residential	100.808	74.938	20.161	18.317	22.631	25.033	21.536
SC&PA LE 250	4.871	4.232	1.141	1.034	0.492	0.761	0.857
SC&PA GT 250	4.730	4.946	1.325	1.209	0.194	0.000	0.682
LC&PA	11.253	11.703	3.168	2.861	1.268	0.000	1.824
SVIS	0.235	0.310	(0.000)	0.076	0.027	0.000	0.026
IVIS	4.077	4.236	0.000	1.035	0.586	0.000	0.405
LVIS	3.158	3.076	(0.000)	0.752	0.596	0.000	0.337
LIS	2.287	2.086	0.000	0.510	0.000	0.000	0.127
Total	**131.419**	**105.528**	**25.794**	**25.794**	**25.793**	**25.794**	**25.794**
Small Business	*21.090*	*21.192*	*5.633*	*5.180*	*1.981*	*0.761*	*3.389*
Rate Class Share of the Proposed Increase							
Residential	76.7%	71.0%	78.2%	71.0%	87.7%	97.0%	83.5%
SC&PA LE 250	3.7%	4.0%	4.4%	4.0%	1.9%	3.0%	3.3%
SC&PA GT 250	3.6%	4.7%	5.1%	4.7%	0.8%	0.0%	2.6%
LC&PA	8.6%	11.1%	12.3%	11.1%	4.9%	0.0%	7.1%
SVIS	0.2%	0.3%	0.0%	0.3%	0.1%	0.0%	0.1%
IVIS	3.1%	4.0%	0.0%	4.0%	2.3%	0.0%	1.6%
LVIS	2.4%	2.9%	0.0%	2.9%	2.3%	0.0%	1.3%
LIS	1.7%	2.0%	0.0%	2.0%	0.0%	0.0%	0.5%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**
Small Business	*16.0%*	*20.1%*	*21.8%*	*20.1%*	*7.7%*	*3.0%*	*13.1%*
Percent Distribution Rate Increase							
Residential			26.9%	24.4%	30.2%	33.4%	28.7%
SC&PA LE 250			27.0%	24.4%	11.6%	18.0%	20.3%
SC&PA GT 250			26.8%	24.4%	3.9%	0.0%	13.8%
LC&PA			27.1%	24.4%	10.8%	0.0%	15.6%
SVIS			0.0%	24.4%	8.6%	0.0%	8.3%
IVIS			0.0%	24.4%	13.8%	0.0%	9.6%
LVIS			0.0%	24.4%	19.4%	0.0%	11.0%
LIS			0.0%	24.4%	0.0%	0.0%	6.1%
Total			**24.4%**	**24.4%**	**24.4%**	**24.4%**	**24.4%**
Small Business			*26.6%*	*24.4%*	*9.3%*	*3.6%*	*16.0%*

Notes:

1) The OSBA proposed rate increase was based on a first dollar relief methodology, with a $10 million overall reduction in the proposed increase. This table scales that proposed increase up to NFGD's full proposed increase, for comparison purposes.

EXHIBIT IEc-R2

EXAMPLE OF FIRST DOLLAR RELIEF

BASED ON NFGD COSS "B"

Exhibit IEc-R2
Proposed First Dollar Relief for Commercial Customers ($ millions); NFGD COSS "B"

	(1) NFGD "B" Allocated Cost Proposed Rates	(2) Revenues at Present Rates	(3) NFGD Proposed Rate Revenue Increase	(4) NFGD Proposed Total Revenue Increase	(5) NFGD Proposed Class Revenues	(6) Revenue-Cost Ratios at NFGD Proposed Rates	(7) Reduced Cost Basis	(8) FDR for LC&PA and SC&PA GT 250
Residential	96.547	74.938	20.161	20.237	95.175	98.6%	89.200	
SC&PA LE 250	4.687	4.232	1.141	1.145	5.377	114.7%	4.330	(0.757)
SC&PA GT 250	5.008	4.946	1.325	1.330	6.276	125.3%	4.627	(1.330)
LC&PA	12.891	11.703	3.168	3.180	14.883	115.5%	11.911	(2.175)
SVIS	0.253	0.310	(0.000)	(0.000)	0.310	122.5%	0.234	
IVIS	5.084	4.236	0.000	0.000	4.236	83.3%	4.697	
LVIS	4.461	3.076	(0.000)	(0.000)	3.076	69.0%	4.122	
LIS	2.488	2.086	0.000	0.000	2.086	83.8%	2.299	
Total	**131.419**	**105.528**	**25.794**	**25.892**	**131.419**	**100.0%**	**121.42**	**(4.262)**
Residential	*96.547*	*74.938*	*20.161*	*20.237*	*95.175*	*98.6%*	*89.200*	*0.000*

	(9) NFGD Proposed Increase After FDR	(10) NFGD Proposed Revenues After FDR	(11) Revenue-Cost Ratio After FDR	(12) Proportional Scaleback of Cost Reduction	(13) Increase After FDR and Scaleback	(14) Class Revenues After FDR and Scaleback	(15) Revenue-Cost Ratio after FDR and Scaleback	(16) Percent Revenue Increase
Residential	20.237	95.175	106.7%	(5.369)	14.868	89.807	100.7%	19.8%
SC&PA LE 250	0.388	4.620	106.7%	(0.103)	0.285	4.517	104.3%	6.7%
SC&PA GT 250	0.000	4.946	106.9%	0.000	0.000	4.946	106.9%	0.0%
LC&PA	1.005	12.708	106.7%	(0.267)	0.738	12.442	104.5%	6.3%
SVIS	(0.000)	0.310	132.6%	0.000	(0.000)	0.310	132.6%	0.0%
IVIS	0.000	4.236	90.2%	(0.000)	0.000	4.236	90.2%	0.0%
LVIS	(0.000)	3.076	74.6%	0.000	(0.000)	3.076	74.6%	0.0%
LIS	0.000	2.086	90.7%	0.000	0.000	2.086	90.7%	0.0%
Total	**21.630**	**127.158**	**104.7%**	**(5.738)**	**15.892**	**121.419**	**100.0%**	**15.1%**
Residential	*20.237*	*95.175*	*106.7%*	*(5.369)*	*14.868*	*89.807*	*100.7%*	*19.8%*

Notes:
(1) Cost basis is OTS/OCA preferred COSS methodology, NFGD alternative B. Return and income taxes are allocated based on rate base.
(2) Revenues at present rates include rate revenues and other revenues.
(3) NFGD proposed rate increase is based on values in Exhibit 103 Schedule 1-A (non-seasonal) proof of revenues.
(4) NFGD proposed increase in other revenues based on late charge allocation in NFGD COSS "A" and "B."
(5) Sum of columns (2) and (4).
(6) Ratio of column (5) to column (1).
(7) Reduction of $10.00 million in revenue requirement. Costs allocated in proportion to column (1).
(8) FDR is lesser of the NFGD proposed increase and the difference between class R/C ratio and the residential R/C ratio (from column (6)), multiplied by class allocated costs in column (1).
(9) Equals column (4) plus column (8). That is, NFGD proposed increase less FDR.
(10) Equals column (2) plus column (9). That is, present revenues plus increase after FDR (or NFGD proposed revenues less FDR).
(11) Ratio of column (10) to column (1).
(12) Total amount is total reduction from column (7) less FDR from column (8). That amount is allocated in proportion to column (9).
(13) Equals column (9) plus column (12). That is, increase after FDR less proportional scaleback credit.
(14) Equals column (2) plus column (13). That is, present revenues plus increase after FDR and after scaleback.
(15) Ratio of column (14) to column (1).
(16) Increase in column (14) divided by present rates in column (2).

OTS Statement No. 1
Witness: Kevan Deardorff

ORIGINAL

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Docket No. R-00061493

Direct Testimony

of

Kevan Deardorff

Office of Trial Staff

Concerning:

Rate of Return

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevan L. Deardorff. My business address is P.O. Box 3265, Harrisburg, Pa. 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by the Pennsylvania Public Utility Commission as a Fixed Utility Financial Analyst. I am assigned to the Office of Trial Staff (OTS) as an expert witness.

Q. PLEASE DESCRIBE THE ROLE OF OTS IN RATE PROCEEDINGS.

A. OTS was established by the legislature and is responsible for protecting the public interest in rate proceedings. The OTS analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers and the Company.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I have prepared this information in Appendix A supplementing my direct testimony.

I. Subject of Testimony

Q. PLEASE IDENTIFY THE ISSUES THAT ARE ADDRESSED IN YOUR TESTIMONY.

A. The issues addressed in my direct testimony concern rate of return, including the capital structure, the cost of common equity, and the overall fair rate of return for National Fuel Gas Distribution Corporation (NFGD or Company).

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT THAT SUPPORTS YOUR RECOMMENDATIONS WITH RESPECT TO A FAIR RATE OF RETURN?

A. Yes. OTS Exhibit No. 1 presents the analyses that I have conducted regarding rate of return.

II. Background Discussion

Q. HOW DOES THE RATE OF RETURN COMPONENT FIT WITHIN THE REVENUE REQUIREMENT FORMULA?

A. The revenue requirement formula is as follows:

$$RR = E + D + T + ((V-d) \times R)$$

Where:

RR	=	Revenue Requirement
E	=	Operating Expense
D	=	Depreciation Expense
T	=	Taxes
V	=	Gross Rate Base
d	=	Accrued Depreciation
R	=	Overall Rate of Return

In the above formula, the rate of return is expressed as a percentage. The calculation of that rate is independent of the determination of the appropriate rate base value for ratemaking purposes. As such, the appropriate total dollar return is dependent upon the proper computation of the rate of return and the proper valuation of the Company's rate base.

Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?

A. A fair and reasonable overall rate of return is one which will allow the utility the opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period its rates will be in effect.

The Bluefield Water Works and Hope Natural Gas cases of 1923 and 1944, respectively (cited below), set forth the principles that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia, 262 U.S. 679, 692-93 (1923).

It is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with risks on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

While interpretations of these excerpted citations may vary somewhat, they provide general guidelines for the regulator to determine a fair rate of return.

Q. WOULD YOU PLEASE EXPLAIN HOW YOU CALCULATED YOUR OVERALL RATE OF RETURN?

A. Yes. The overall rate of return in this rate proceeding is calculated using the weighted average cost of capital method, which is the interaction of the following components: the percentage of long-term debt, the percentage of common equity, the cost of long-term debt and the cost rate of common equity. First, it is necessary to determine the proportion of each type of capital (referred to as the capital structure) which has financed the rate base and assign the appropriate cost rate to each. The cost rate of debt is fixed and can be computed accurately. The cost rate of common equity is not fixed and is much more difficult to measure.

The overall rate of return is then calculated using the proportions of capital and cost rates for each type of capital. OTS Exhibit No. 1, Schedule 1, demon-

strates the interaction of the capital structure and the cost rates of each type of capital. By multiplying each capital component's capital ratio by its associated cost rate, a weighted cost rate is derived for each capital component. The overall rate of return is the sum of weighted cost rates.

III. Company Position

Q. WHAT IS THE COMPANY'S RATE OF RETURN CLAIM IN THIS CASE?

A. Mr. Frank J. Hanley, the Company's cost of capital witness, Mr. David P. Bauer, and Mr. Eric H. Meinl recommended the following rate of return for NFGD:

	Weighted Capital Structure (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	40.04	6.64	2.66
Short-Term Debt	8.46	6.03	0.51
Common Equity	51.50	12.25	6.31
Total	100.00		9.48

Source: NFGD Statement 10, page 2.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. At pages 16 and 17 of NFGD Statement No. 10, Mr. Hanley states that it is inappropriate to use either NFGD's or NFG's capital structures because they are both too heavily weighted with equity. At page 19 Mr. Hanley states that he is recommending a hypothetical capital structure based on S&P's criteria for a utility with an "A" bond rating and a business profile of 4.

Q. WHAT IS THE BASIS FOR THE COMPANY'S COST OF LONG-TERM DEBT CLAIM?

A. The calculation of NFGD's cost rate of long-term debt is shown on Page 3, of NFGD Exhibit No. 406. Mr. David P. Bauer's recommended long-term debt cost rate is 6.64 percent.

Q. WHAT IS THE BASIS FOR THE COMPANY'S COST OF SHORT-TERM DEBT CLAIM?

A. The calculation of the NFGD's cost rate of short-term debt is also shown on Page 3 of Exhibit No. 406. At page 6 of Statement No 8, Mr. Bauer explains that his recommended short-term debt cost rate of 6.03 percent is based on three parts; NFG's current cost of short-term borrowings is 5.2%, a 10 basis point

increase expected by the first quarter of 2007, and the .73% committed line of credit fee.

Q. WHAT IS THE BASIS FOR THE COMPANY'S COST OF EQUITY CLAIM?

A. Mr. Hanley summarizes his cost of equity analysis on pages 3 through 7 of NFGD Statement No. 10, wherein he recommends that a range of 12.00 - 12.25 percent common equity cost rate be used in this proceeding. To determine his cost of common equity, Mr. Hanley states that he relied on the Discounted Cash Flow (DCF) approach, the Risk Premium (RP) Model, the Capital Asset Pricing Model (CAPM), and the Comparable Earnings Model (CEM). He applied the DCF, RP, and the CAPM methods to a group of nine LDCs and to a group of four LDCs. The CEM was applied to a barometer group of sixty-four unregulated companies and another group of thirty-six unregulated companies. The results from these models ranged from 10.19% to 14.56%. Finally, Company witness Eric H. Meinl recommends using the top end of Mr. Hanley's range in order to reward the Company for overall strength of management and to provide sufficient incentive for the Company to continue to invest in natural gas infrastructure.

IV. OTS Position

Q. WILL YOU PLEASE SUMMARIZE YOUR RECOMMENDATION FOR NFGD?

A. The following is a summary of my rate of return recommendation for NFGD:

	Weighted Capital Structure (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	***40.67***	6.64	***2.70***
Short-Term Debt	***11.58***	6.03	***0.70***
Common Equity	***47.75***	***8.75***	***4.18***
Total	100.00		***7.58***

Source: OTS Ex. No. 1, Sch. No. 1.

Q. HAVE YOU ADOPTED ANY ELEMENTS OF THE COMPANY'S RECOMMENDATION IN ARRIVING AT YOUR POSITION?

A. Yes. I have adopted NFGD's cost rates of long-term and short-term debt. I have also accepted the two barometer groups the Company witness has proposed.

Q. HOW DOES YOUR RECOMMENDATION DIFFER FROM THE COMPANY'S CLAIM?

A. In the table above, I have italicized and bolded the numbers where my recommendation differs from the Company's rate of return claim. My recommendation differs in three areas: capital structure, cost rate of common equity and overall rate of return. I recommend a capital structure consisting of

40.67 percent long-term debt, 11.58 percent short-term debt, and 47.75 percent common equity. I recommend an 8.75 percent cost rate of common equity for NFGD in lieu of Mr. Meinl's 12.25 percent recommendation. As a result, my overall rate of return is 7.55 percent for NFGD.

V. Capital Structure

Q. WHAT IS THE BASIS FOR YOUR CAPITAL STRUCTURE RECOMMENDATION?

A. My recommendation is based on a hypothetical permanent capital structure that is representative of the industry norms.

Q. WHY HAVE YOU CHOSEN TO USE A HYPOTHETICAL CAPITAL STRUCTURE?

A. I have chosen to use a hypothetical capital because the Company's proposed permanent capital structure (without short-term debt) is not representative of the industry norm. OTS Ex. No. 1, Sch. No. 2, p. 2 presents a comparison of the Company's proposed capital structure at January 31, 2007 to the Value Line's estimated capital structure for the Barometer groups of nine and four gas companies[1]. NFGD's projected actual equity ratio is 67.30 percent compared to the Gas Groups' equity ratios of 53.25 and 54.63 percent. Based on these industry

[1] Comparison is based on permanent capital since Value Line only makes projections of capital structure based on permanent capital.

averages I propose a hypothetical capital structure based on permanent capital of 54 percent equity and 46 percent long-term debt. This hypothetical capital structure is more representative of industry norms than Mr. Hanley's proposed permanent capital structure.

Q. WHAT CAPITAL STRUCTURE ARE YOU RECOMMENDING FOR RATEMAKING PURPOSES?

A. Since gas storage is included in rate base and is financed by short-term debt it is appropriate to include short-term debt in the capital structure. OTS Ex. No. 1, Sch. No. 2, p. 1 presents the calculation of adding back the short-term debt balances into the hypothetical capital structure of 54 percent equity and 46 percent debt. However, since Value Line does not make projections of short-term debt, I use the Company's thirteen month average for the future test year of $103,493,000 as the appropriate level of short-term debt to be in the proposed capital structure. As a result, my recommended hypothetical capital structure for ratemaking purposes is 40.67 percent long-term debt, 11.58 percent short-term debt and 47.75 percent common equity.

VI. Cost of Common Equity

Q. WHAT IS THE BASIS FOR YOUR 8.75 PERCENT COST OF EQUITY RECOMMENDATION?

A. I used the Discounted Cash Flow (DCF) method applied to a barometer group of gas distribution companies to determine my 8.75 percent cost rate of common equity. To compute the various components of the DCF method, I relied upon current, historical, and forecasted market data for each company in the two barometer groups and National Fuel Gas Company (NFG), NFGD's parent.

Q. HAVE YOU INCLUDED AN ANALYSIS OF NFGD MARKET DATA?

A. No. NFGD has no common stock publicly traded, therefore, no meaningful financial data is available to directly determine the cost of common equity for NFGD. NFG, on the other hand, has sufficient financial and market data. However, for reasons that I will explain directly, NFG should be used only as one source in determining a cost of capital and fair rate of return.

Q. WHY DO YOU USE BAROMETER GROUPS AS YOUR PRIMARY SOURCE TO DETERMINE THE COST RATE OF COMMON EQUITY?

A. I have chosen barometer groups as my primary source of information for several reasons. First, NFG is classified as a diversified natural gas company. Diversified natural gas companies in general are more risky than natural gas

distribution companies. The Value Line Investment Survey at 12/3/2004 reports that the average beta for the diversified natural gas companies is 1.18 while the average beta for the distribution companies is .87. NFG's beta is .95. Second, the use of data for one company may be less reliable than using a barometer group, because the data for one company may be subject to particular events that can cause short-term aberrations in the marketplace. The rate of return on common equity for a single company could become distorted in such circumstances. The use of barometer groups has the effect of smoothing out any event aberrations associated with a single company.

A barometer group of companies is also used as a benchmark to satisfy the long established guideline of providing a utility the opportunity to earn a return equal to that of similar risk enterprises.

Q. WHAT BAROMETER GROUPS DID YOU USE FOR YOUR ANALYSIS?

A. I adopted Mr. Hanley's barometer groups of four and nine gas distribution companies that are presented in NFGD Exhibit No. 400, Schedule 1, page 12. I find these companies to be representative of the gas distribution industry.

Q. DOES YOUR COST OF EQUITY ANALYSIS TAKE CHANGING BUSINESS AND ECONOMIC CONDITIONS INTO ACCOUNT?

A. Yes. The financial markets take all factors into account when assessing investments. The aggregate risks of an investment are reflected in the stock price per share. The data for the barometer groups that I have utilized are market based; therefore, assuming that the equity markets are reasonably efficient, my results have implicitly accounted for all these factors.

Q. WHAT ECONOMIC FACTORS DO YOU CONSIDER IMPORTANT IN YOUR ANALYSIS OF COST OF CAPITAL?

A. I have made comparisons of important economic variables and have examined their impact on gas utilities over the past twenty-four years. OTS Ex. No. 1, Sch. No. 3 presents a historical perspective of the Mergent's "Aaa" Corporate Bond Yield, the U.S. Treasury Bill rate (T-Bill), the prime rate, and the percent change in the Consumer Price Index (CPI) compared to the average dividend yield of my barometer group for the same period. This schedule also presents a sampling of economic experts' quarterly forecasts for 2006 and 2007 and yearly forecasts for the period 2007 to 2016.

Q. IS THERE A RELATIONSHIP BETWEEN DIVIDEND YIELDS OF GAS COMPANIES AND "Aaa" BOND YIELDS?

A. Yes. A comparison of the "Aaa" bond yields and dividend yields in OTS Ex. No. 1, Sch. No. 3 reveals a direct relationship between these two variables. The correlation coefficient of the two arrays is .97, which indicates a very strong relationship[2]. This high correlation should be expected since all capital costs are extremely competitive. As a result, I believe it's important in determining an appropriate cost rate of common equity to recognize this relationship. Any potential impact related to a projected change in bond yields should be considered in recommending a representative dividend yield for the prospective period.

Q. WHAT HAS BEEN THE HISTORICAL TREND OF PUBLIC UTILITY BOND YIELDS AND THE BAROMETER GROUP'S DIVIDEND YIELDS?

A. The trend in "Aaa" rated bond yields and gas utility dividend yields, presented in OTS Ex. No. 1, Sch. 3, has been a steady decline over the past 24 years. Since 1982, "Aaa" rated corporate bond yields have decreased from 13.79 percent to 5.24 percent through 2005, or 855 basis points. Over the same time period, the nine company barometer group's average dividend yield declined from 11.69 percent to 4.25 percent resulting in a decline of 744 basis points.

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[2] Correlation coefficients range between 1 and -1. A correlation coefficient of 1 indicates a perfect positive relationship. A correlation coefficient of -1 indicates a perfect negative relationship. A correlation coefficient of 0 indicates no relationship exists.

Q. WHAT IS THE OUTLOOK FOR INTEREST RATES IN RELATION TO THE FORECASTED INFLATION RATE?

A. OTS Ex. No. 1 Sch. No. 3 also presents short-term and long-term forecasts published by Blue Chip Financial Forecasts. Over the next two years, forecasting professionals are expecting T-Bill yields to be between 4.80 and 5.30 percent and forecasted inflation to be between 2.30 and 3.00 percent. As a result, the real rate of interest[3] is expected to be in the 2.20 to 2.70 percent range for this future period. In relation to the historical average, the expected real of rate interest is well within the long-term range of 2 to 3 percent.

Forecasting professionals are also expecting interest rates on long-term "Aaa" rated corporate bonds to remain fairly stable with a slight increase from 6.20 percent in the third quarter of 2006 to 6.3 percent for most of 2007. These forecasts reflect the belief that investors can expect real Gross Domestic Product (GDP) growth to remain relatively weak at between 2.8 to 3.1 percent over the next two years[4].

Investors' expectations are, however, continually changing and influenced by Federal Reserve policy. The Federal Reserve's tight monetary policy of recent years has done much to alleviate inflationary fear. However, with the recent emphasis on economic growth both in monetary and fiscal policy, inflationary

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[3] The real rate of interest is the actual rate of interest minus the inflation rate.

[4] Blue Chip Financial Forecasts, August 1, 2006.

fears have again become a concern. As a result, the Federal Reserve has increased the Federal Funds rate from 1.00% in May 2004 to 5.25% in July, 2006 in an attempt to preempt inflationary pressures.

Q. WHAT IS THE OUTLOOK FOR INTEREST RATES FOR THE LONG-TERM?

A. OTS Ex. No. 1, Sch. No. 3 further presents extended forecasts for the various interest rates. Expectations are for the "Aaa" corporate bond yield to be in the range of 6.2 to 6.5 percent and the U.S. Treasury Bills to be in the range of 4.5 to 5.0 percent over the next ten years.

Q. WILL YOU PLEASE EXPLAIN YOUR DCF ANALYSIS?

A. My analysis employs the standard DCF model, $k = D_1/P_0 + g$, where D_1 is the dividend expected during the year, P_0 is the current price of the stock, and g is the expected growth rate of dividends. For purposes of calculating a dividend yield applicable to the formula, D_0/P_0 (the current dividend divided by the current price) must be adjusted by ½ the expected growth rate[5] in order to account for changes in the dividend rate in period 1. The alternative preferred method for

[5] The adjustment of ½ the growth rate is used when the timing of the dividend increase is not known for certain. It could occur next month or the twelfth month. On average it is safe to assume that the increase will occur half way through the prospective year. Therefore, an adjustment by 1/2 the expected growth rate is appropriate.

calculating the dividend yield is simply dividing the Value Line projected dividend for period 1 by P_0.

Q. PLEASE STATE THE RESULTS OF YOUR DISCOUNTED CASH FLOW (DCF) ANALYSIS.

A. The following table summarizes the results of my DCF analysis:

	Range	Average
Nine Company Barometer Gp.	8.64 - 8.90%	8.77%
Four Company Barometer Gp.	8.41 - 8.76%	8.59%
National Fuel Gas Company	8.33 - 8.74%	8.53%

Source: OTS Ex. No. 1, Sch. 4, p. 1, 2 and 3, col. 3.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS THAT WERE USED IN YOUR DCF ANALYSIS?

A. A representative dividend yield must be calculated over a time frame that avoids the problems of short-term aberrations and "stale" data series. For purposes of my DCF analysis, I placed equal emphasis on the most recent spot and 52 week average dividend yields. The following table summarizes my dividend yield computations for the barometer group:

	Dividend Yields (Adjusted)		
	Spot 6/23/06 (%)	52-week Average (%)	Average (%)
Nine Company Barometer Gp.	4.14%	4.40%	4.27%
Four Company Barometer Gp.	3.91%	4.26%	4.09%
National Fuel Gas Company	3.18%	3.59%	3.38%

Source: OTS Ex. No. 1, Sch. 4, p. 1, 2, and 3, col. 1.

Q. WHAT INFORMATION DID YOU RELY UPON TO DETERMINE YOUR EXPECTED GROWTH RATE?

A. To arrive at a representative dividend growth rate, I surveyed several series of projected growth rates. These growth rates are presented in OTS Ex. No. 1, Sch. No. 4, p. 4. My growth rate estimates are based on a survey of established forecasting entities including Value Line, Standard and Poor's (S&P), Yahoo First Call, Clear Station, Smart Money, MSN Money Central, and Morningstar.

Q. WHY HAVE YOU LIMITED YOUR SURVEY TO ANALYSTS' GROWTH RATE FORECASTS IN YOUR DETERMINATION OF AN OVERALL GROWTH RATE?

A. The bulk of the research evidence has indicated analysts' growth forecasts are superior to historically oriented growth measures in forecasting growth.

Forecasting professionals have already accounted for historical data in their estimates along with expectations of a wide array of economic variables. In my opinion, to give any weight to historical growth rates would result in a double count.

Q. WHAT DO YOU CONCLUDE TO BE A REASONABLE GROWTH RATE FOR YOUR BAROMETER GROUP OF NINE GAS DISTRIBUTION COMPANIES?

A. I conclude that investors could expect to achieve a growth rate of 4.50 percent for the nine company barometer group.

Q. WHAT LEADS YOU TO BELIEVE THAT INVESTORS SHOULD EXPECT TO ACHIEVE A GROWTH RATE OF 4.50 PERCENT FOR THE NINE COMPANY BAROMETER GROUP?

A. The expected growth rates for the nine company barometer group are presented on OTS Ex. No. 1, Sch. No. 4, p. 4. The barometer group average growth rates expected by Value Line, S&P, Yahoo First Call, Clear Station, Smart Money, MSN, and Morningstar are 5.2, 4.4, 4.4, 4.7, 3.6, 4.7, and 4.2 percent, respectively. The average growth rate for these seven sources is 4.46 percent. The average growth rate excluding the 0 percent growth rates for Cascade Natural Gas Corp. and Laclede Gas Co. reported by Smart Money is 4.61 percent. From this

information I conclude that an investor could reasonably expect to achieve a growth rate for the nine company barometer group of 4.50 percent.

Q. WHY HAVE YOU EXCLUDED THE 0 PERCENT GROWTH RATE FOR CASCADE AND LACLEDE FROM THE SECOND AVERAGE GROWTH RATE?

A. The 0 percent growth rate that Smart Money reports is apparently a reporting error. Clear Station, Smart Money, and MSN get their growth estimates from the same source. Clear Station and MSN report that the growth rate for Cascade and Laclede are not available while Smart Money reports a 0 percent growth rate. Clearly 0 percent is out of line with the other sources for Cascade's and Laclede's growth rates. As a result, I surmise that Smart Money made a reporting error.

Q. WHAT DO YOU CONCLUDE TO BE A REASONABLE GROWTH RATE FOR YOUR BAROMETER GROUP OF FOUR GAS DISTRIBUTION COMPANIES?

A. I conclude that investors could expect to achieve a growth rate of 4.50 percent for the four company barometer group.

Q. WHAT LEADS YOU TO BELIEVE THAT INVESTORS SHOULD EXPECT TO ACHIEVE A GROWTH RATE OF 4.50 PERCENT FOR THE FOUR COMPANY BAROMETER GROUP?

A. The expected growth rates for the four company barometer group are presented on OTS Ex. No. 1, Sch. No. 4, p. 4. The barometer group average growth rates expected by Value Line, S&P, Yahoo First Call, Clear Station, Smart Money, MSN, and Morningstar are 6.5, 4.0, 4.0, 4.4, 3.3, 4.4, and 4.0 percent, respectively. The average growth rate for these seven sources is 4.37 percent. The average growth rate excluding the 0 percent growth rates for Cascade Natural Gas Corp. and Laclede Gas Co. reported by Smart Money is 4.53 percent. From this information I conclude that an investor could reasonably expect to achieve a growth rate for the four company barometer group of 4.50 percent.

Q. WHAT DO YOU CONCLUDE TO BE A REASONABLE GROWTH RATE FOR NFG?

A. I conclude that investors could expect to achieve a growth rate of 5.15 percent for NFG.

Q. WHAT LEADS YOU TO BELIEVE THAT INVESTORS SHOULD EXPECT TO ACHIEVE A GROWTH RATE OF 5.15 PERCENT FOR THE FOUR COMPANY BAROMETER GROUP?

A. The expected growth rates for the four company barometer group are presented on OTS Ex. No. 1, Sch. No. 4, p. 4. The growth rates for NFG expected by Value Line, S&P, Yahoo First Call, Clear Station, Smart Money, MSN, and Morningstar are 1.5, 5.0, 5.0, 5.8, 5.8, 5.8, and 5.0 percent, respectively. The average growth rate for these seven sources is 4.84 percent. The average growth rate excluding Value Line is 5.40 percent. From this information I conclude that an investor could reasonably expect to achieve a growth rate for NFG of 5.15 percent.

Q. WHY HAVE YOU EXCLUDED VALUE LINE FROM THE SECOND AVERAGE GROWTH RATE?

A. My overall recommendation gave Value Line less weight for two reasons. First, Value Line's estimate is a single analyst's estimate. Research indicates that consensus estimates are superior to single analyst's estimates[6]. Second, Value Line's time frame methodology for growth rate projections can give distorted results. Value Line calculates growth rates for three different time frames and then averages the three to get the final result. If one of the beginning periods

[6] An Evaluation of Alternative Measures of Analysts' Forecasts of Growth in the Constant Growth Model, Stephen G. Timme and Peter C. Eisemann, Center for the Study of Regulated Industry.

earnings are either on the high side or low side the resulting growth estimate will also be skewed either high or low.

Q. WHAT COST RATE OF COMMON EQUITY IS INDICATED FROM THE RESULTS OF YOUR DCF ANALYSIS?

A. Given these representative dividend yields and my recommended growth rate, I calculated the DCF return with the results presented on pages 1, 2, and 3 of Schedule No. 4. The nine company barometer group results range from 8.64 to 8.90 percent. The four company barometer group results range from 8.41 to 8.76 percent. The DCF results for NFG range from 8.32 to 8.71 percent.

Q. WHAT COST RATE OF EQUITY DO YOU RECOMMEND FOR NFGD?

A. Based primarily on the DCF results for the barometer groups, I recommend that the appropriate cost rate of common equity for the LDC industry on average is in the range of 8.50 to 9.00 percent. Based upon this range, I recommend an 8.75 percent cost rate of common equity for NFGD.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Since the hypothetical capital structure for ratemaking purposes was based on the barometer group average, a financial risk adjustment is not necessary; therefore the midpoint of my range is appropriate.

Q. HAVE YOU TAKEN INTO CONSIDERATION MARKET PRESSURE AND SELLING AND ISSUANCE EXPENSES IN MAKING YOUR RECOMMENDATION?

A. Yes. I have considered these items but have not made any adjustments to account for them. I believe that market pressure, selling and issuance expenses are an additional cost of capital that are incurred at the time of issuance. However, the current market price of common stock already reflects these items, as investors have already capitalized market pressure and issuance expenses in determining the value of the stock at the time of purchase. Since my analyses are market based, these items have been taken into consideration. As a result, I have made no additional adjustments to account for market pressure, selling, and issuance expenses.

Q. WHAT OTHER ISSUE SHOULD THE COMMISSION CONSIDER IN THE DETERMINATION OF AN APPROPRIATE COST RATE OF COMMON EQUITY?

A. OTS witness Kubas testified at OTS Statement No. _ that a reduction in the Company's return on equity is appropriate if the Commission approves an EEE Rider for NFGD.

Q. WHY SHOULD THE APPROVAL OF THE EEE RIDER REQUIRE A REDUCTION IN NFGD'S RETURN ON EQUITY?

A. The approval of the EEE Rider would increase the Company's guaranteed revenues to 94.5 percent of total revenues, which means that only 5.5 percent of the Company's revenues are at risk. These guarantees reduce NFGD's earnings volatility and the overall risk to NFGD.

Q. HOW MUCH OF A REDUCTION IN THE COST OF EQUITY WOULD YOU RECOMMEND IF THE EEE RIDER WERE APPROVED?

A. I recommend the bottom of my cost of equity range of 8.50 percent if the Commission approves the EEE Rider.

VII. Overall Weighted Cost of Capital

Q. WHAT IS THE OVERALL WEIGHTED COST OF CAPITAL FOR NFGD?

A. OTS Ex. No. 1, Sch. No. 1, p. 1 presents the calculation of NFGD's' overall weighted cost of capital. Based upon my 8.75 percent cost rate of common equity, the appropriate overall weighted cost of capital is 7.58 percent.

VIII. Critique of the Company's Cost of Capital Testimony

Q. PLEASE SUMMARIZE YOUR CRITIQUE OF THE COMPANIES' COST OF CAPITAL TESTIMONY.

A. I have three primary areas of disagreement concerning Mr. Hanley's cost of capital testimony and Mr. Meinl's recommendation.

- First, Mr. Hanley's market to book adjustment is not appropriate.
- Second, Mr. Hanley has incorrectly given equal weight to the Risk Premium, CAPM, ECAPM, and Comparable Earnings methods in his recommendation.
- Third, Mr. Meinl's recommendation to use the top of Mr. Hanley's cost of equity range is not appropriate.

Q. WHY SHOULD MR. HANLEY'S MARKET/BOOK ADJUSTMENT BE REJECTED?

A. Mr. Hanley's 88 to 107 basis points adjustment[7] for the M/B greater than 1.0 should be rejected for several reasons. First, the fact that gas distribution companies' M/Bs are in excess of 1.0 is more an indicator that these companies are earning in excess of the required rate of return, rather than under earning. An investor earning exactly his rate of return would price the stock at book value. Only when the earnings on book exceed the required rate of return will an investor

[7] NFGD Exhibit No. 400, Schedule 8, Page 1.

bid the price of the stock above book value. The possibility of market to book adjustment being added to the return investors currently require will give investors the incentive to bid prices even higher and cause the M/B ratio to rise above the current level. The problem then becomes one of circularity. Following Mr. Hanley's logic, he would have to claim an even higher adjustment for the ever-increasing M/B ratios with every future rate case. Clear evidence of this phenomenon appeared in the last three Aqua Pennsylvania Inc. (Aqua) rate cases. Aqua's witness claimed an M/B adjustment of 47 basis points in 2001, 64 basis points in 2003 and 103 basis points in 2005.

Q. DOES PRECEDENT SUPPORT ADJUSTING THE COST RATE OF COMMON EQUITY DUE TO DISPARITY BETWEEN MARKET PRICE AND BOOK VALUE?

A. No. In Blue Mountain Consolidated Water Company, 426 A.2d 724; (Pa. Cmwlth. 1981), the Commonwealth Court remanded a case to the PA PUC for a more comprehensive explanation of the fair rate of return and its integral common equity capital costs. In the remanded proceeding, the Commission stated the following:

> (3) Market price-book value ratios are not a goal of regulation but a result of regulation, general economic factors and individual company's characteristics of management, operations and perceived future.
> 55 PUR 503, (January 14, 1982)

I wholly concur with the Commission. The result of the Commission's long-term sole use of the DCF method and informed judgment has produced market prices well in excess of book value. Thus there is clearly no need to adjust the DCF upward in that it has consistently provided a fair rate of return for utilities in Pennsylvania.

Q. WHY SHOULD MR. HANLEY'S METHODOLOGY, WHICH WEIGHTS THE RISK PREMIUM AND CAPM RESULTS EQUALLY WITH THE DCF RESULTS, BE REJECTED FOR THE DETERMINATION OF THE APPROPRIATE COST OF CAPITAL?

A. To understand why these rate of return methods should be rejected for cost of capital purposes, it must first be understood how investors use these methods in their decision making process. The Capital Asset Pricing Model (CAPM) and Risk Premium (RP) methods give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the historical period when the risk premiums were determined. By comparing CAPM and RP results with current expected equity returns (DCF results), an investor can make rational buy and sell decisions. When expected DCF returns are higher than those indicated by the CAPM and RP historical norms, an investor would have an incentive to buy, and vice versa.

The relevancy of these methods does not carry over from the investment decision making process to the regulatory process, because regulators can never be

certain that economic and regulatory conditions underlying the historical period during which the risk premiums were calculated are the same today or in the future.

Q. GIVEN THE FACT THAT ECONOMIC AND REGULATORY CONDITIONS TODAY ARE DIFFERENT FROM THE HISTORICAL PERIOD, HOW DOES THIS AFFECT THE RISK PREMIUMS USED IN MR. HANLEY'S RP AND CAPM MODEL?

A. The CAPM and RP models do not measure the current rate of return on common equity directly, as does the DCF model. These methods determine the rate of return on common equity by indirectly observing the current and expected cost of debt. An implicit assumption when using risk premium methods is that the variables determining the equity cost rate and debt cost rate are the same, which allows the analyst to apply a constant risk premium. Actually, the variables determining the cost rates in the two markets are different. Changing economic conditions cause these variables in the two markets to change, resulting in changing risk premiums over time. While betas do change over time thus effecting changes in the risk premium, it is not reflective of current market conditions because the betas are calculated using five years of historical data.

Q. IS THERE ANY ACADEMIC EVIDENCE THAT QUESTIONS THE CREDIBILITY OF THE CAPM MODEL?

A. Yes. An article, which appeared in the New York Times on February 18, 1992, summarizes a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French (OTS Ex. No. 1, Sch. No. 5). Their study examined the importance of beta (CAPM's risk factor) in explaining returns on common stock. In CAPM theory, the higher a stock's beta, the higher the expected return on that stock. They found that the model did not do well in predicting actual returns and suggest the use of more elaborate multi-factor models. As a result of this information, I believe that rational investors will give less credibility to expected equity returns that are calculated using the simple CAPM model.

Q. BESIDES THE THEORETICAL PROBLEMS WITH THE CAPM, ARE THERE ANY APPLICATION PROBLEMS WITH MR. HANLEY'S CAPM?

A. Yes. Mr. Hanley also employs a variation of the CAPM known as the Empirical Capital Asset Pricing Model (ECAPM). Mr. Hanley states the reason for this is "low beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted". The use of this model to correct for this problem is unnecessary and yields biased results.

Q. WHY DO YOU BELIEVE THE USE OF THE ECAPM YIELDS BIASED RESULTS?

A. Mr. Hanley uses Value Line betas in his ECAPM. In Value Lines description of their betas they state "There is a tendency over the years for high Beta stocks to become lower and for low Beta stocks to become higher. This tendency can be measured by studying the Betas of stocks in consecutive five-year intervals. The Betas published by The Value Line Investment Survey are adjusted for this tendency and hence are likely to be a better predictor of future Betas than those based exclusively on the experience of the past five years." By employing the adjusted Value Line Betas in the ECAPM, Mr. Hanley is over compensating for the beta stability problem resulting in biased over estimates.

Q. MR. HANLEY ALSO BELIEVES THAT THE COMPARABLE EARNINGS MODEL (CEM) SHOULD BE GIVEN EQUAL WEIGHT. WHY SHOULD THIS METHOD BE REJECTED FOR RATEMAKING PURPOSES?

A. There are several faults with Mr. Hanley's CEM that render it inappropriate for rate making purposes. First, Mr. Hanley measured the historical earnings/book value ratios of non-utility companies. Mr. Hanley has provided absolutely no evidence that these *accounting* returns for non-utilities bear any relationship to a *market* based return for gas utilities. Moreover, this method completely contradicts the premise underlying his other methods. In all of the other methods, Mr. Hanley measured returns based upon market values, including the bond

returns that he subtracted from the common stock returns to determine his risk premia.

Q. WHAT IS THE COMMISSION'S HISTORICAL TREATMENT OF THE COMPARABLE EARNINGS APPROACH?

A. The Commission has long recognized the problem with this method. Regarding to the use of non-utility companies' historical book earnings in an attempt to determine a cost of equity for a utility the Commission has stated:

> The use of nonregulated companies as a comparable group for regulated firms under the comparable earnings method of computing a rate of return on common equity requires numerous unsupportable assumptions and results in a highly speculative finding.

Pennsylvania Public Utility Commission v. Philadelphia Electric Co. (1980) 33 PUR4th 319, 341 (1980).

Additionally, the Commission has stated:

> NFGD employed comparable earnings as a check on the common equity cost rates produced by its other methodology. NFGD M.B. p. 170. NFGD did not use comparable earnings as a common equity cost rate determinant. Additionally, it was noted that comparable earnings are not market related but accounting related ratios.

PaPUC v. National Fuel Gas Distribution Corp., Docket No. R-00940021, p. 199, Order entered December 1, 1994.

Q. ARE THERE ANY OTHER REASONS WHY MR. HANLEY'S CEM RESULTS SHOULD BE REJECTED?

A. Yes. The companies in Mr. Hanley's CEM barometer groups are simply not comparable to gas utilities in terms of their business risk/financial risk profile. Gas distribution utilities, being monopolies with very low business risk, are able to maintain higher financial risk profiles by employing more leverage. Conversely, Mr. Hanley's CEM barometer group companies, being in an unregulated competitive environment with much higher business risk, must maintain lower financial risk profiles by employing minimal leverage. As evidence of this, OTS Ex. No. 1, Sch. No. 6, p. 1, presents the debt ratios for the barometer groups of LDCs compared to Mr. Hanley's CEM barometer groups. Mr. Hanley's two CEM barometer groups have an average debt ratio of only 34.19% and 37.61%, compared to a debt ratio of 55.00% and 53.10% for the two LDC barometer groups.

Q. WHAT OTHER RATIO SHOWS THAT THE CEM BAROMETER GROUPS ARE NOT COMPARABLE TO THE GAS INDUSTRY?

A. Schedule 6 also presents the percent of institutional holdings of the unregulated companies used in Mr. Hanley's CEM analysis and the Gas Groups. Institutional investors hold 66.69% and 68.01% of the shares of the unregulated companies compared to 49.44% and 50.55% for the Gas Groups. Clearly, institutional

investors view the unregulated companies used in Mr. Hanley's CEM analysis differently than they do LDCs.

Q. YOU STATED THAT MR. ERIC MEINL IS RECOMMENDING THE HIGH END OF MR. HANLEY'S COST OF EQUITY RANGE. DID HE ADEQUATELY SUPPORT THIS CLAIM?

A. No. Mr. Meinl is requesting the high end of the cost of equity range, 12.25%, as a reward for the overall strength of management. As delineated earlier in my direct testimony, the landmark Bluefield Water Works & Improvement Company. V. Public Service Commission of West Virginia, 262U.S. 679, 692-93 (1923), the setting of an appropriate cost rate of common equity assumes efficient and economical management. Mr. Meinl did not provide any evidence to support the claim that NFGD's management is more efficiently and economically operated in comparison to the companies in Mr. Hanley's barometer groups. Without such evidence, Mr. Meinl's claim should be rejected.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

APPENDIX A

Kevan L. Deardorff
Educational and Professional Background

I am a graduate of the Pennsylvania State University, where I received a Bachelor of Science Degree in Business Economics and Finance and a Master of Arts Degree in Economics. Before coming to the Pennsylvania PUC in 1983, I worked as a consultant for the United States Environmental Protection Agency between 1980 and 1981, and as a Research Economist for the Pennsylvania Department of Commerce during 1982.

I am currently employed as a Fixed Utility Financial Analyst III. I have completed rate of return analyses in a large number of rate cases and assisted in the analyses of many electric, gas, water and telephone rate cases. I have prepared testimony concerning rate of return, discount rate, price cap, and merger benefits in the following cases:

Keystone Water Company	R-822211-12
	R-822215-19
	R-822221
Western Pennsylvania Water Company	R-832381
Philadelphia Suburban Water Company	R-842592
Duquesne Light Company	R-842583
Western Pennsylvania Water Company	R-842621-25
Riverton Consolidated Water Company	R-842675
Keystone Water Company	R-842755-56
	R-842759
Equitable Gas Company	R-842769
Western Pennsylvania Water Company	R-850096-97
West Penn Power Company	R-850220
Dauphin Consolidated Water Supply Co.	R-860350
Western Pennsylvania Water Company	R-860397
Philadelphia Electric Company (Gas Division)	R-870629
National Fuel Gas Distribution Corp.	R-870719
Western Pennsylvania Water Company	R-870825
Philadelphia Suburban Water Company	R-870840
Equitable Gas Company	R-880971
Chartiers Natural Gas Company	R-891283
Columbia Gas of Pennsylvania, Inc.	R-891468
Arrowhead Public Service Corp.	R-891557
Pennsylvania-American Water Co.	R-901652
Citizens Utilities Water Company of Pennsylvania	R-901663
Citizens Utilities Home Water Company	R-901664
National Fuel Gas Distribution	R-901670

York Water Company	R-901813
Columbia Gas of Pennsylvania, Inc.	R-901873
National Fuel Gas Distribution Corp.	R-911912
The Peoples Natural Gas Company	R-00922180
York Water Company	R-00922168
Pennsylvania & Southern Gas Company	R-00922312
North Penn Gas Company	R-00922276
North East Heat and Light Company	R-00922309
Shenango Valley Water Company	R-00922420
Mechanicsburg Water Company	R-00922502
National Fuel Gas Distribution Corp.	R-00932548
Roaring Creek Water Company	R-00932665
Shenango Valley Water Company	R-00932798
The Peoples Natural Gas Company	R-00932866
Blue Mountain Consolidated Water Co.	R-00932873
Allied Gas Company, et. al.	R-00932952
National Fuel Gas Distribution Corp.	R-00942991
Borough of Media Water Works	R-00943098
Newtown Artesian Water Company	R-00943157
Roaring Creek Water Company	R-00943177
Borough of Schuylkill Haven	R-00943156
Pennsylvania Power & Light Company	R-00943271
National Fuel Gas Distribution Corp.	R-00953299
Frontier Companies	P-00951005
PFG Gas, Inc. and North Penn Gas Company	R-00953524
Commonwealth Telephone Company	P-00961024
PECO Energy Company	R-00973877
PECO Energy Company	R-00973953
Pennsylvania Power & Light Company	R-00973954
Ironton Telephone Company	P-00971182
Metropolitan Edison Company	R-00974008
Pennsylvania Electric Company	R-00974009
Pennsylvania Power Company	R-00974149
PG Energy, Inc.	R-00984280
ALLTEL Pennsylvania, Inc.	P-00981423
Pennsylvania Telephone Association Small Group	P-00981425, et al
United Telephone Company of Pennsylvania	P-00981410
City of Lancaster Water Fund	R-00984567
York Water Company	R-00994605
Pittsburgh Thermal, L.P.	R-00994641
PECO Energy Company	A-110550F0147
PG Energy	R-00005119
City of Lancaster Sewer Fund	R-00005109

PFG Gas, Inc. and North Penn Gas Company	R-00005277
Emporium Water Company	R-00005050
T.W. Phillips Gas and Oil Company	R-00005459
Verizon North, Inc.	P-00001854
Metropolitan Edison Company	P-00001860
Pennsylvania Electric Company	P-00001861
Philadelphia Gas Works	R-00006042
Pennsylvania American Water Company	R-00016339
Wellsboro Electric Company	R-00016356
Verizon Pennsylvania Inc.	R-00016683
Philadelphia Suburban Water Company	R-00016750
Philadelphia Gas Works – Extraordinary Rate Relief	R-00017034F
Verizon Pennsylvania Inc.	R-00930715F0002
York Water Company	R-00027975
National Fuel Gas Distribution Corp.	R-00038168
Pennsylvania American Water Company	R-00038304
Aqua Pennsylvania, Inc.	R-00038805
Duquesne Light Company	P-00032071
PPL Electric Utilities Corporation	R-00049255
Valley Energy Inc.	R-00049345
Wellsboro Electric Company	R-00049313
National Fuel Gas Distribution Corporation	R-00049656
Pike County Light & Power Company	R-00049884
Township of Falls – Sewer Fund	R-00049557
PECO Energy Company	A-110550F016
MESCO, Inc.	R-00050678
Aqua Pennsylvania, Inc.	R-00051030
United Water Pennsylvania, Inc.	R-00051186
Metropolitan Edison Company	R-00061366
Pennsylvania Electric Company	R-00061367
PG Energy	R-00061365
PPL Gas Utilities Corporation	R-00061398

OTS Exhibit No. 1
Witness: Kevan Deardorff

ORIGINAL

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Docket No. R-00061493

Exhibit to Accompany

the

Direct Testimony

of

Kevan Deardorff

Office of Trial Staff

Concerning:

Rate of Return

OTS Exhibit No. 1
Schedule No. 1

National Fuel Gas Distribution Corporation
OTS Recommended Weighted Cost of Capital
at January 31, 2007

		Capital Structure (1)	Cost Rates (2)	Weighted Cost of Capital (3=1x2)
[1]	Long-Term Debt	40.67%	6.64%	2.70%
[2]	Short-Term Debt	11.58%	6.03%	0.70%
[3]	Common Equity	47.75%	8.75%	4.18%
[4]	Total	100.00%		7.58%

National Fuel Gas Distribution Corporation
Recommended Capitalization Structure
estimated at January 31, 2007

		Hypothetical Capital Structure (w/o S-T Debt) (1)	Capitalization ($000) (2)	Hypothetical Capital Structure (incl. S-T Debt) (3)
(1)	Long-Term Debt	46.00%	$ 363,412.00	40.67%
(2)	Common Equity	54.00%	$ 426,613.00	47.75%
(3)	Total Permanent Capital	100.00%	$ 790,025.00	88.42%
(4)	Short-Term Debt		$ 103,493.00	11.58%
(5)	Total Capital Employed		$ 893,518.00	100.00%

Sources: OTS Exhibit No. 1, Schedule No. 2, Page 2
NFGD Gas Exhibit No 400, Schedule 6, Page 2

National Fuel Gas Distribution Corporation
Capitalization Structure Comparison

		NFGD 1/31/07 (2)	Nine Company Group 2006 (3)	Four Company Group 2006 (3)
(1)	Long-Term Debt	32.70%	46.53%	45.37%
(2)	Preferred Stock	0.00%	0.22%	0.00%
(3)	Common Equity	67.30%	53.25%	54.63%
(4)	Total	100.00%	100.00%	100.00%

Sources: Value Line Investment Survey, June 16, 2006
NFGD Exhibit No. 400, Schedule 6, Page 2.

Comparison of Key Economic Variables to the Dividend Yields for the
Barometer Group of Gas Distribution Companies
for 1982 to 2005 and Estimates for 2006 to 2016

	Year	Mergent's 'Aaa' Corporate Bond Yield	U.S. Treasury Bills	Prime Rate	CPI Percent Change	Barometer Group Dividend Yields
		(1)	(2)	(3)	(4)	(5)
(1)	1982	13.79	10.69	14.86	3.80	11.69
(2)	1983	12.04	8.63	10.79	3.80	10.46
(3)	1984	12.71	9.58	12.04	4.00	9.57
(4)	1985	11.37	7.48	9.93	3.80	7.89
(5)	1986	9.02	5.98	8.33	1.10	6.80
(6)	1987	9.38	5.82	8.21	4.40	6.80
(7)	1988	9.71	6.69	9.32	4.40	7.39
(8)	1989	9.26	8.12	10.87	4.60	7.10
(9)	1990	9.32	7.51	10.01	6.10	6.64
(10)	1991	8.77	5.42	8.46	3.10	6.63
(11)	1992	8.14	3.45	6.25	2.90	6.13
(12)	1993	7.22	3.02	6.00	2.70	5.15
(13)	1994	7.96	4.29	7.15	2.70	5.48
(14)	1995	7.84	5.51	8.83	2.50	5.95
(15)	1996	7.37	5.02	8.27	3.30	5.03
(16)	1997	7.26	5.07	8.44	1.70	4.96
(17)	1998	6.53	4.81	8.35	1.60	4.61
(18)	1999	7.04	4.66	8.00	2.70	4.83
(19)	2000	7.62	5.85	9.23	3.40	5.53
(20)	2001	7.08	3.45	6.91	1.60	4.91
(21)	2002	6.49	1.62	4.67	2.40	4.90
(22)	2003	5.67	1.02	4.12	1.90	4.93
(23)	2004	5.63	1.38	4.36	3.30	4.54
(24)	2005	5.24	3.16	6.23	3.80	4.25
	Recent Forecasts:					
(25)	2006-3rd Qtr	6.10	5.20	8.30	3.00	
(26)	2006-4th Qtr	6.20	5.30	8.40	2.60	
(27)	2007-1st Qtr	6.20	5.20	8.40	2.60	
(28)	2007-2nd Qtr	6.20	5.10	8.30	2.50	
(29)	2007-3rd Qtr	6.20	5.00	8.10	2.40	
(30)	2007-4th Qtr	6.20	4.80	8.00	2.30	
	Extended Forecasts:					
(31)	2007	6.40	5.00	8.10	2.80	
(32)	2008	6.30	4.80	7.90	2.50	
(33)	2009	6.30	4.60	7.70	2.40	
(34)	2010	6.20	4.50	7.60	2.50	
(35)	2011	6.30	4.60	7.60	2.50	
(36)	2012-16	6.50	4.60	7.70	2.50	

Note: Correlation of C1 and C5 = 0.97

Sources: Economic Indicators, April, 2006
Blue Chip Financial Forecasts, June 1, and August 1, 2006
Mergent Bond Record, Various Issues

Expected Market Cost Rate of Equity
Using Data for the Barometer Group of Nine Gas Distribution Companies

	Time Period	Adjusted Dividend Yield(1) (1)	Growth Rate (2)	Expected Rate of Return (3=1+2)
(1)	52 Week Average (ending 8/18/06)	4.40%	4.50%	8.90%
(2)	Spot Price (ending 8/18/06)	4.14%	4.50%	8.64%
(3)	Average:	4.27%	4.50%	8.77%

Notes: (1) Value Line's reported dividends are projected for the year ahead.

Sources: Value Line, Ratings and Reports, June 16, 2006
Barron's, August 21, 2006

Expected Market Cost Rate of Equity
Using Data for the Barometer Group of Four Gas Distribution Companies

	Time Period	Adjusted Dividend Yield(1) (1)	Growth Rate (2)	Expected Rate of Return (3=1+2)
(1)	52 Week Average (ending 8/18/06)	4.26%	4.50%	8.76%
(2)	Spot Price (ending 8/18/06)	3.91%	4.50%	8.41%
(3)	Average:	4.09%	4.50%	8.59%

Notes: (1) Value Line's reported dividends are projected for the year ahead.

Sources: Value Line, Ratings and Reports, June 16, 2006
Barron's, August 21, 2006

Expected Market Cost Rate of Equity
Using Data for National Fuel Gas Company

	Time Period	Adjusted Dividend Yield(1) (1)	Growth Rate (2)	Expected Rate of Return (3=1+2)
(1)	52 Week Average (ending 8/18/06)	3.56%	5.15%	8.71%
(2)	Spot Price (ending 8/18/06)	3.17%	5.15%	8.32%
(3)	Average:	3.36%	5.15%	8.51%

Notes: (1) Value Line's reported dividends are projected for the year ahead.

Sources: Value Line, Ratings and Reports, June 16, 2006
Barron's, August 21, 2006

Expected Growth Rates
for the Barometer Groups of Gas Distribution Companies

	Company	Value Line Earnings Growth (1)	S & P Earnings Growth (2)	Yahoo Thomson First Call Earnings Growth (3)	Clear Station Earnings Growth (4)	Smart Money Earnings Growth (5)	MSN Earnings Growth (6)	Morning-star Earnings Growth (7)
[1]	Atmos Energy Corporation	7.0	6.0	5.8	5.5	5.5	5.5	5.0
[2]	Cascade Natural Gas Corpor	9.0	3.0	3.0	-	0.0	-	3.0
[3]	Laclede Gas Company	6.0	4.0	5.0	-	0.0	-	4.0
[4]	New Jersey Resources	4.5	6.0	5.5	6.0	6.0	6.0	5.2
[5]	NICOR, Inc.	4.0	3.0	3.0	2.5	2.5	2.5	3.1
[6]	Northwest Natural Gas Comp	7.0	6.0	6.0	4.9	4.9	4.9	5.0
[7]	Peoples Energy Corp.	1.5	4.0	4.0	4.0	4.0	4.0	4.4
[8]	Piedmont Natural Gas Co.	6.0	4.0	4.0	5.8	5.8	5.8	4.8
[9]	WGL Holdings, Inc.	2.0	4.0	3.5	4.0	4.0	4.0	3.7
[10]	Nine Company Average	5.2	4.4	4.4	4.7	3.6	4.7	4.2
[11]	Four Company Average	6.5	4.0	4.0	4.4	3.3	4.4	4.0
[12]	National Fuel Gas	1.5	5.0	5.0	5.8	5.8	5.8	5.0

Sources:

Value Line Investment Survey, June 16, 2006
Internet, Tradingday.com, August 18, 2006
Standard & Poor's Earnings Guide, August, 2006

N.Y. Times Tue Feb 18, 1992

Market Place

A Study Shakes Confidence In the Volatile-Stock Theory

By ERIC N. BERG

One of the most enduring ideas of modern finance is facing its most serious challenge. Two scholars of finance say they have disproved the theory, common among investors, that stocks more volatile than the market as a whole are the best performers.

Eugene F. Fama and Kenneth R. French, business professors at the University of Chicago, traced the performance of thousands of stocks over 50 years but found no link between relative volatility and long-term returns. The many investors who try to beat the market by buying widely swinging issues are misguided, they say.

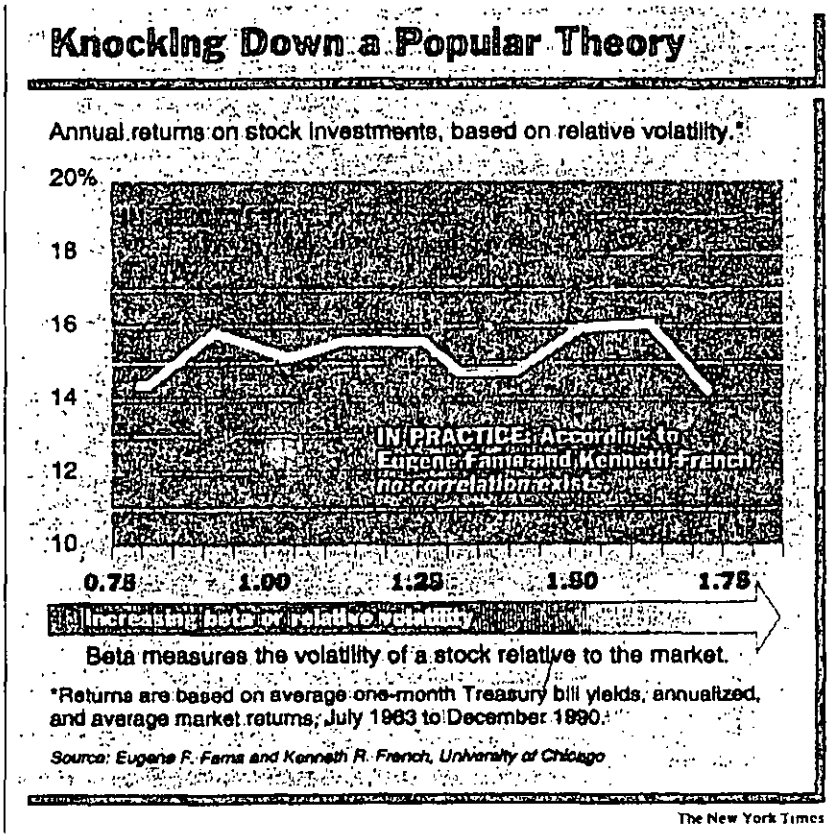
The importance of "beta," the investment community's term for a stock's volatility relative to the market, has long been under challenge. But it is still closely watched by analysts, and business students are still taught that they can earn higher returns by buying stocks whose swings are wider than the market's.

"The fact is," Professor Fama said in a recent telephone interview, "beta as the sole variable explaining returns on stocks is dead."

Some still favor relatively volatile stocks, among them William F. Sharpe, a retired Stanford University professor who won the 1990 Nobel Memorial Prize in Economic Science for theories based on beta. "It is a remarkable set of empirical results about what happened in the past," he said of the University of Chicago study. "But I am not willing to make investment decisions based on the theory that there is no relationship between beta, properly measured, and expected returns."

If Professors Fama and French

Continued on Page D6



A Study Shakes Confidence In the Volatile-Stock Theory

Continued From First Business Page

are right, however, the impact could be far reaching. Some highly volatile groups of stocks that have enjoyed wide followings — airlines, for example — could lose a portion of their appeal if beta-believing investors side with the professors.

Additionally, many executives of publicly held companies have taken the view that if their own company's stock is more volatile than the market as a whole, any project they invest in — from a lowly piece of new equipment to a huge joint venture — must generate an extra high return to compensate investors for swings in the stock's price and earnings. The professors' work could force many companies to rethink the way they approach capital spending, finance scholars say.

Finally, many publicly held utilities have used beta to justify rate requests. They figure the returns that investors demand, given their companies' betas, and develop rate structures that allow them to earn these returns. But recognizing that their low betas tend to argue against large rate increases, a growing number of utilities had already turned to other approaches. More will probably do so if the research of Professors Fama and French gains currency.

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And if investors decide to quit following betas, other theories of market behavior are likely to gain influence. "What we are really taking about is opening the floodgates to a whole new generation of research into what truly drives stock prices," said Anthony B. Sanders, an Ohio State University professor of finance who is currently a visiting professor at the University of Chicago. "Once you hammer a model like the old one closed, you generate all sorts of additional academic interest."

Professor Fama has already won worldwide recognition for his efficient-markets theory — the notion that because investors all have essentially the same information it is impossible to consistently earn returns greater than those justified by the risks.

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Professor Sharpe used Professor Fama's theory as an assumption to develop the capital-asset pricing model, which links returns to risk, as measured by beta.

Professor Sharpe says that a diversified portfolio can reduce the risks peculiar to individual companies — that General Motors stock, for example, will be hurt by a strike. Investors, therefore, earn no rewards for bearing this risk, according to the Sharpe theory.

But investors do earn higher returns for bearing the other type of risk, known as market risk, Professor Sharpe says. This risk, which remains even after an investor diversifies, depends on how much an individual stock is dragged up or down by the market as a whole. Stocks like that of the biotechnology company Genentech, which have betas of more than 1.0, are more volatile than the market, while stocks like that of the power company Consolidated Edison, which have betas of less than 1.0, are calmer than the market.

To calculate market risk, or beta, finance professionals compare changes in the prices of individual stocks with changes in market indicators like the Standard & Poor's 500-stock index. Professor Sharpe and his followers say that in general, the higher a stock's beta, or volatility relative to the market, the greater its long-term returns.

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Professors Fama and French disagree. Their paper, just published by the University of Chicago's Center for Research in Security Prices, says that long-term returns depend not on beta, but on company size and price-to-book ratios. Smaller companies, as measured by the market value of their shares, and those with low prices relative to their book values have in fact outperformed the market, they say.

The professors theorize that investors view smaller companies as more vulnerable to economic downturns and therefore demand higher returns. They also say that low price-to-book ratios typically reflect financial problems, another reason for investors to demand higher returns.

Professors Fama and French are by no means the first to fire an intellectual salvo at the capital-asset pricing model. Since Professor Sharpe developed the model in the early 1960's, a broad array of rival theories has emerged to explain stock price movements: the January effect, which says that stocks usually gain at the beginning of the year, to the weekend effect, which says stocks generally perform poorly on Mondays. Most recently, the arbitrage pricing theory says that stocks are driven by powerful economywide forces like unanticipated inflation and spikes in interest rates.

But finance experts say that Professors Fama and French have presented the most conclusive evidence against beta.

"What they have proven fairly rigorously is what other academics have been talking about for some time," said Richard Roll, a finance professor at the University of California at Los Angeles, who with others developed the arbitrage pricing theory.

Equity Issues This Week

Comparison of Debt to Total Capital Ratios and Percent Institutional Holdings
for Mr. Hanley's CEM Groups Compared to Mr. Hanley's Gas Groups

	Company	Debt Ratio (1)	Percentage Institutional (2)
[1]	CEM Group (64 Companies)	34.19%	66.69%
[2]	CEM Group (36 Companies)	37.61%	68.01%
[3]	Ms. Hanley's Four Company Gas Group	55.00%	49.44%
[4]	Ms. Hanley's Nine Company Gas Group	53.10%	50.55%

Source: Value Line Investment Survey

Note: Referrence OTS Exhibit No. 1, Schedule 6, Pages 2 and 3.

Debt to Total Capital Ratios and Percent Institutional Holdings
for the CEM Group of 64 Companies
at December 31, 2005

	Company	Debt Ratio (1)	Percentage Institutional (2)
[1]	Alexander & Baldwin	22.60%	77.89%
[2]	Allstate Corp.	21.62%	67.50%
[3]	AptarGroup	15.15%	86.52%
[4]	Astoria Financial	84.13%	63.54%
[5]	Automatic Data Proc.	1.29%	72.25%
[6]	Avery Dennison	95.67%	79.77%
[7]	BOK Financial	46.69%	17.18%
[8]	Baldor Electric	18.94%	56.75%
[9]	Banta Corp.	12.14%	86.47%
[10]	Bard (C.R.)	0.05%	82.70%
[11]	Beclon Dickinson	24.42%	85.38%
[12]	BuckeyePartners L.P.	54.24%	16.44%
[13]	Burlington Northern	41.33%	77.34%
[14]	CLARCOR Inc.	3.21%	82.17%
[15]	ConocoPhillips	16.94%	69.02%
[16]	Crescent Real Est.	64.53%	61.18%
[17]	Cullen/Frost Bankers	26.83%	66.19%
[18]	Delphi Fin'l 'A'	23.51%	77.28%
[19]	Duke Realty Corp.	47.48%	64.67%
[20]	Dun & Bradstreet	0.13%	86.96%
[21]	Fannie Mae	92.14%	83.53%
[22]	Federal Realty Inv. Trust	64.21%	103.13%
[23]	Federated Investors	23.31%	59.28%
[24]	Fifth Third Bancorp	61.72%	64.70%
[25]	First Horizon National	61.75%	43.81%
[26]	Freddie Mac	93.19%	87.06%
[27]	GlaxoSmithKline ADR	41.05%	10.08%
[28]	Golden West Fin'l	82.69%	76.44%
[29]	Graco Inc.	0.00%	78.76%
[30]	HCC Insurance Hldgs.	15.45%	96.15%
[31]	HNI Corp.	14.89%	50.34%
[32]	Hillenbrand Inds	26.68%	56.29%
[33]	Hospitality Properties	33.19%	58.39%
[34]	Hudson City Bancorp	71.19%	54.38%
[35]	ITT Corp.	15.94%	40.76%
[36]	Lancaster Colony	0.00%	95.67%
[37]	Liz Claiborne	17.26%	85.46%
[38]	Markel Corp.	30.42%	72.08%
[39]	McGraw-Hill	0.00%	75.08%
[40]	Media General 'A'	29.87%	74.33%
[41]	Minerals Techn.	4.97%	102.39%
[42]	New Plan Excel R'lty	52.19%	58.25%
[43]	Occidential Petroleum	16.05%	79.72%
[44]	Packaging Corp.	45.86%	79.29%
[45]	Penn R.E.I.T.	52.09%	67.84%
[46]	People's Bank	21.82%	24.62%
[47]	Pfizer Inc.	8.82%	62.12%
[48]	Plum Creek Timber	46.48%	48.38%
[49]	Progressive (Ohio)	17.38%	70.65%
[50]	Reinsurance Group	24.04%	52.47%
[51]	SAFECO Corp.	23.85%	70.46%
[52]	Sigma-Aldrich	18.67%	78.00%
[53]	Simon Property	69.27%	69.14%
[54]	Sysco Corp.	25.74%	66.20%
[55]	TCF Financial	75.24%	63.65%
[56]	TD Banknorth Inc.	43.16%	23.97%
[57]	Tribune Co.	30.56%	54.05%
[58]	Trizec Properties	50.15%	73.46%
[59]	Universal Corp.	44.13%	91.64%
[60]	V.F. Corp.	18.62%	88.18%
[61]	Valspar Corp.	39.97%	69.94%
[62]	Walgreen Co	0.00%	62.77%
[63]	Washington R.E.I.T.	63.26%	44.14%
[64]	Weis Markets	0.00%	23.87%
	Average	34.19%	66.69%

Source: Value Line Investment Survey

Debt to Total Capital Ratios and Percent Institutional Holdings
for the CEM Group of 36 Companies
at December 31, 2005

	Company	Debt Ratio (1)	Percentage Institutional (2)
[1]	Allstate Corp.	21.62%	67.50%
[2]	BOK Financial	46.73%	17.12%
[3]	BRE Properties	53.58%	76.17%
[4]	Bank of Hawaii	25.93%	65.38%
[5]	Cedar Fair L.P.	50.94%	22.59%
[6]	Chevron Corp.	16.22%	59.43%
[7]	City National Corp.	25.35%	62.41%
[8]	Duke Realty Corp.	47.48%	64.67%
[9]	Ecolab Inc.	23.95%	52.67%
[10]	Equity Office P'ptys	59.10%	88.44%
[11]	Equity Residential	58.45%	87.78%
[12]	Exxon Mobil Corp.	5.30%	50.40%
[13]	First Horizon National	61.75%	43.81%
[14]	Gannett Co.	41.80%	83.17%
[15]	Genuine Parts	15.65%	71.64%
[16]	Harte-Hanks	9.95%	57.15%
[17]	Kimco Realty	54.64%	63.25%
[18]	Liberty Property	53.84%	93.62%
[19]	Markel Corp.	30.42%	72.08%
[20]	McClatchy Co.	8.97%	40.20%
[21]	McGraw-Hill	0.00%	75.08%
[22]	Mercury General	8.05%	42.38%
[23]	Moody's Corp.	49.23%	89.52%
[24]	New York Times	35.16%	78.18%
[25]	Pitney Bowes	74.73%	79.09%
[26]	Plum Creek Timber	46.48%	48.38%
[27]	Protective Life	26.76%	78.15%
[28]	Simon Property Group	69.27%	69.14%
[29]	St. Joe Corp.	53.13%	75.80%
[30]	Transatlantic Hldgs.	0.00%	95.41%
[31]	Union Pacific	33.03%	79.27%
[32]	United Dominion R'lty	74.04%	74.69%
[33]	Universal Corp.	44.13%	91.64%
[34]	Wal-Mart Stores	36.17%	108.31%
[35]	Washington Federal	63.88%	58.33%
[36]	Webster Fin'l	28.26%	65.66%
[37]	Average	37.61%	68.01%

Source: Value Line Investment Survey

OTS Statement No. 2
Witness: Janet M. Markovich

ORIGINAL

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

NATIONAL FUEL GAS DISTRIBUTION COMPANY

Docket No. R-00061493

Direct Testimony

of

Janet M. Markovich

Office of Trial Staff

Concerning:

Operation & Maintenance Expenses
Cash Working Capital
Merchant Function Charge
POR Pilot Program

Q. STATE YOUR FULL NAME, EMPLOYER AND BUSINESS ADDRESS.

A. My name is Janet M. Markovich. I am employed by the Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. WHAT IS YOUR POSITION WITH THE PENNSYLVANIA PUBLIC UTILITY COMMISSION?

A. I am a Fixed Utility Financial Analyst in the Office of Trial Staff (OTS).

Q. PLEASE DESCRIBE THE ROLE OF OTS IN RATE PROCEEDINGS.

A. OTS was established by the Pennsylvania Legislature in 1986 and is responsible for representing the public interest in rate proceedings. The OTS analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of the ratepayers and the Company.

Q. WHAT ARE YOUR DUTIES AS AN ANALYST IN OTS?

A. My duties as an OTS Analyst include participation in formal base rate proceedings as an expert witness. In that capacity, I prepare and present OTS testimony and exhibits. My education and professional background are set forth in the attached Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Based upon my review of the National Fuel Gas Distribution Corporation (Company or NFGD) base rate filing, I am recommending adjustments to the Company's claims for operation and maintenance (O&M) expenses and cash working capital (CWC) claim for the test year ended January 31, 2007.

Q. PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENTS.

A. I am recommending the following adjustments:

Issue	**Reduction**
Rate Case Expense – Normalization	$ 280,397
Payroll	$ 83,061
Benefits	$ 396,454
Uncollectible Accounts	
Regular Claim	$ 1,301,199
LIRA Arrearage Forgiveness	($503,433)
Research and Development (GTI)	$ 350,476
Advertising	
Co-op Advertising	$ 150,000
Amortizations	
OPEB Deferral - R-00049656	$ 463,194
OBEBDeferral - R-00061493	$ 547,635
Pipeline Integrity	$ 1,040,497
FERC 2004	$ 407,680
EEE	$ 1,800,000
OPEB Subsidy	$ 160,000
Total	$ 6,477,160
Rate Base	
Cash Working Capital	$ 3,682,000
Rate Base Piece Payroll	$ 24,810
Total	$ 3,706,810

RATE CASE EXPENSE

Q. IN THIS PROCEEDING, THE COMPANY HAS MADE A CLAIM FOR RATE CASE EXPENSE. WOULD YOU BRIEFLY EXPLAIN THE NATURE AND TYPE OF EXPENSES CLASSIFIED AS RATE CASE EXPENSE?

A. The estimated costs that comprise a company's allowable claim for rate case expense are those that are incurred to compile, present and defend a request for a base rate increase before the Commission. The estimated costs that are typically found in a rate case expense claim include legal fees for outside counsel, fees to outside consultants and printing, collating and postal expenses.

Q. A KEY ISSUE CONCERNING THE RECOVERY OF RATE CASE EXPENSE IS WHETHER THE CLAIM SHOULD BE NORMALIZED. WOULD YOU BRIEFLY DISCUSS THE CONCEPT OF NORMALIZATION?

A. Normalization is a ratemaking concept that describes the transformation of an operating expense that recurs at irregular intervals into a "normal" annual test year expense allowance. Normalization specifically addresses the prospective recovery of an ongoing expense that recurs sporadically. Allowed normalized expenses are no different than any other O&M expense in that the company is given the opportunity to achieve full recovery.

Q. HOW DOES THE COMMISSION TREAT RATE CASE EXPENSE FOR RATEMAKING PURPOSES?

A. The Commission views prudently incurred rate case expense as an ongoing, although recurring at irregular intervals, expense related to the rendering of utility service. As such, rate case expense is subject to normalization for ratemaking purposes. A company's history regarding the frequency of rate case filings is an essential element in determining the normalized level of rate case expense for ratemaking purposes.

Q. HOW IS THE FREQUENCY OF RATE CASE FILINGS DETERMINED?

A. The frequency is properly determined by computing the average number of months that expire between the filing dates of a company's base rate case filings. The number of base rate case filings used to compute the average is a matter of judgment.

Q. AFTER DETERMINING THE FILING FREQUENCY OF BASE RATE FILINGS, HOW IS THE NORMALIZED EXPENSE CLAIM DETERMINED?

A. The estimated prudently incurred rate case expenses are multiplied by a fraction, the numerator being 12 months and the denominator the number of months representing the frequency of filings.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE CASE EXPENSE IN THIS PROCEEDING?

A. The Company's future test year (FTY) claim for rate case expense in the current proceeding is $841,192 to be normalized over 12 months.

Q. WHAT IS THE BASIS FOR THE COMPANY'S FUTURE TEST YEAR CLAIM OF $841,192?

A. The Company included estimated expenses for outside services in the areas of Rate of Return, Lead Lag Study, Depreciation, and Legal expertise. The Company used costs from the two most recent rate cases for each category of expertise, adjusted for inflation to 2007 price levels and then calculated an average to arrive at the estimated costs for the current proceeding. Finally, the Company requested a normalization period of 1 year resulting in the annual FTY claim of $841,192 as shown in the Company's filing at NFGD Vol. III, Ex. No. 104, Sch. 2 (Rate Case), p. 27.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED ONE YEAR NORMALIZATION PERIOD?

A. In response to OTS-RE-18 section D, NFGD witness Friedrich-Alf stated that the Company anticipates that it will be filing rate cases on an annual basis due to its budget for construction of non-revenue producing plant, its continuing loss of load and increases in operating expenses and capital costs (OTS Ex. No. 2, Sch. 1, p.

2).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR RATE CASE EXPENSE?

A. No. I disagree with the Company's claimed normalization period of one year.

Q. WHAT IS YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. I recommend a normalization period of 18 months. This recommendation results in a total test year allowance of $560,795 ($841,192 ÷ 18 x 12) and a reduction to the Company's claim of $280,397 ($841,192 - $560,795)

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED NORMALIZATION PERIOD?

A. My recommendation is based on my review of the Company's history of filing rate cases. A company's history regarding the frequency of base rate filings is the primary consideration in determining the time period for the normalization of rate case expense. The standard procedure for determining the frequency is to calculate the time period of the interval between the filing dates of the most recent cases, including the instant proceeding. The following is the most recent history of the Company's base rate filings:

Docket No.	Date Filed
R-00061493	5/31/2006
R-00049656	9/15/2004
R-00038168	4/13/2003

The two intervals between the three filing dates are 17 and 20.5 months respectively. I calculated the average of those two intervals to arrive at the recommended 18 month normalization period.

Q. WHY IS YOUR RECOMMENDATION BASED ON THE COMPANY'S HISTORY OF RATE FILINGS?

A. Again, my recommendation is based on the Company's history of rate filings because a company's history regarding the frequency of base rate filings is the primary consideration in determining the time period for the normalizing of rate case expense. Although, the Company has claimed the intention to file a rate case in one year, the Commission does not make this decision based on a company's intentions. Additionally, the Company made the claim of a one- year normalization period in its previous two filings and as I have shown above the intended year was actually 17 months and 20.5 months.

UNCOLLECTIBLE ACCOUNTS EXPENSE

Q. PLEASE EXPLAIN WHAT IS MEANT BY UNCOLLECTIBLE ACCOUNTS.

A. Uncollectible accounts are specific receivables that are determined to be uncollectible in whole or in part, either because debtors do not pay and/or the creditors finds it impracticable to enforce payment. Those accounts deemed uncollectible are charged against income.

Q. HOW DO UTILITIES GENERALLY RECOGNIZE UNCOLLECTIBLE ACCOUNTS FOR RATEMAKING PURPOSES?

A. Generally, for ratemaking purposes, utilities compute uncollectible accounts expense on an annual prospective basis. While the uncollectible accounts expense is a prospective claim, the proper calculation begins with an historic analysis of actual net write-offs to gross revenues to develop an historic write-off ratio. Net write-offs are gross write-offs less recoveries of amounts previously written off. This ratio is then applied to projected revenues to determine the proper prospective allowance.

Q. WHAT IS THE COMPANY CLAIM FOR UNCOLLECTIBLE ACCOUNTS EXPENSE IN THIS PROCEEDING?

A. The Company's claim of $8,437,198 is found in NFGD Ex. No. 104, Sch. 2 (Uncollectibles), pp. 6-7.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim for uncollectible accounts expense is based on the latest twenty-four months ratio of net write-offs to billed revenues. The Company used data for the twelve months ended January 31, 2005, and 2006. The Company applied this ratio to the FTY forecasted revenues to calculate the uncollectible accounts claim of $8,437,198 for the FTY ending January 31, 2007.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. I recommend that uncollectible account expense be based on a write-off ratio that is calculated using three years of data (OTS Ex. No. 2, Sch. 2, pp.1-2) Additionally, I recommend that LIRA write-offs (arrearage forgiveness) be removed from the calculation. LIRA is the Company's customer assistance program. The recommended three year write-off ratio without LIRA is 1.68. This recommendation will result in a reduction to the Company's uncollectible accounts expense claim of $1,301,199 and if accepted, I recommend an increase in expenses of $503,433 for LIRA arrearage forgiveness.

Q. WHAT IS THE BASIS FOR THE USE OF A WRITE-OFF RATIO THAT IS CALCULATED USING THREE YEARS OF DATA?

A. The basis for using three years of data to calculate the write-off ratio that is applied prospectively, is to have a sample of data that is large enough to smooth any abnormally low or high year from affecting the ratio. For example, I calculated the write-off ratio for each of the past five years in the same manner as the Company calculated the write-off ratio for two years (without deducting LIRA arrearage forgiveness) and found the following write-off ratios (OTS Ex. No. 2, Sch. 2, p. 3):

Year	Ratio	Net Write-offs
2002	1.288	$ 3,403,202
2003	2.295	6,612,838
2004	1.519	3,907,131
2005	1.844	5,645,305
2006	2.127	6,866,444

In this example, we observe that the ratios have not steadily increased over the 5-year sample but have fluctuated as 2003 is the highest ratio in the sample and 2002 is the lowest and the ratios for 2005 and 2006 are in the high end of the range. Therefore, using the most recent three years provides a mid range sample which results in a ratio of 1.853 ($16,418,880 ÷ $886,108,247) before the LIRA arrearage forgiveness is deducted (OTS Ex. No. 2, Sch 2, pp. 3-4). After the LIRA adjustment, the 1.853 reduces to the OTS recommended write-off ratio of 1.68.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO REMOVE LIRA FORGIVENESS FROM THE WRITE-OFF RATIO CALCULATION?

A. LIRA write-offs should be removed because these amounts are fixed and do not vary at different levels of revenues. When a customer enters the LIRA program, the customer's prior arrearages are placed in suspense status and collections are not pursued. Each month that the LIRA customer timely pays its current bill, $1/24^{th}$ of the prior arrearages are forgiven and charged to uncollectible accounts expense. These pre-established balances for existing LIRA accounts customers will not increase as a result of this rate increase. With respect to the current average level of 10,350 LIRA customers, this expense should decrease as customers fully extinguish their prior arrearages. Uncollectible accounts expense related to arrearage forgiveness should be projected independently of normal uncollectibles. To date, no other utility has attempted to combine the two for ratemaking purposes and NFGD has failed to provide any rationale for including arrearage forgiveness in developing a normal uncollectible accounts expense claim. Therefore the LIRA write-offs should not be iterated as part of NFGD's uncollectible accounts expense claim.

Q. HOW WAS YOUR RECOMMENDATION TO INCREASE EXPENSES FOR THE LIRA ALLOWANCE DETERMINED?

A. I averaged the three most recent years (2004 through 2006) of net write-offs that represent LIRA arrearage forgiveness charged to expense. This allowance was calculated for the months ended (TME) as follows:

Year	Amount
TME January 2004	$ 307,772
TME January 2005	537,847
TME January 2006	664,679
Total	$1,510,298 ÷ 3 = $503,433

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE RATEMAKING ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS EXPENSE.

A. I am recommending that the write-off ratio be based on an historic three year average and that LIRA arrearage forgiveness be removed from the ratio. The total adjustment is $1,301,199 less the O&M allowance for LIRA arrearage forgiveness of $503,433 for a net recommended adjustment of $797,766 ($1,301,199 - $503,433).

PAYROLL EXPENSE – NOT SUBJECT TO WAGE INCREASES

Q. WHAT IS PAYROLL EXPENSE – NOT SUBJECT TO WAGE INCREASES?

A. Payroll expense not subject to wage increases includes payments to employees for

lump-sum merit increases, severance, moving expenses, suggestion awards, employee stock ownership plan, tuition aid, meter reading incentives and miscellaneous income.

Q. WHAT IS THE COMPANY'S CLAIM FOR PAYROLL EXPENSE – NOT SUBJECT TO WAGE INCREASES?

A. The Company's FTY claim for payroll expense not subject to wage increases is $476,900. The Company has determined that 77 percent or $367,213 is included in O&M expenses.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM FOR PAYROLL EXPENSE – NOT SUBJECT TO WAGE INCREASES?

A. The basis for the Company's FTY claim is the actual amount experienced in the historic test year of January 2006.

Q. *DO YOU AGREE WITH THE COMPANY'S CLAIM REGARDING PAYROLL EXPENSE– NOT SUBJECT TO WAGE INCREASES?*

A. No.

Q. WHAT DO YOU RECOMMEND REGARDING PAYROLL EXPENSE – NOT SUBJECT TO WAGE INCREASES?

A. I recommend an allowance of $369,029. This recommendation results in an

adjustment reducing the Company's claim by $107,871 ($476,900 - $369,029). After applying the allocation factor of 77 percent, the O&M reduction is $83,061($107,871 x 77%) and the reduction to rate base is $24,810 ($107,871-$83,061).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION REGARDING PAYROLL EXPENSE – NOT SUBJECT TO WAGE INCREASES?

A. My recommendation is based on a three-year average of actual payroll expenses not subject to wage increases. The calculation follows:

Date	Expenditure
TME January 2004	$ 362,523
TME January 2005	$ 267,663
TME January 2006	$ 476,900
Total	$1,107,086 ÷ 3 = $ 369,029

Due to the fluctuating nature of the payroll related items included in this category, I applied the concept of normalization to this expense.

AMORTIZATIONS

Q. PLEASE EXPLAIN THE CONCEPT OF AMORTIZATION.

A. Amortization is an accounting procedure that extinguishes an atypical, nonrecurring expense over a predetermined number of years by charging to operations a pro rata share based on the selected amortization period. Although a claim for an unrecovered normalized expense would be disallowed if requested in

a subsequent rate case, an amortization expense allowance could be claimed in succeeding rate cases as long as there is a remaining unamortized balance.

AMORTIZATION - OTHER POST RETIREMENT BENEFITS (OPEB) SETTLEMENT AT R-00049656

Q. WHAT IS THE COMPANY'S CLAIM FOR THE AMORTIZATION OF OPEB SETTLEMENT AT R-00049656?

A. The Company's claim is $502,673 for the amortization of OPEB settlement at Docket No. R-00049656 as shown in the Company's filing in Ex. No. 104, Sch. 2 (Benefits), p. 14.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM FOR THE AMORTIZATION OF OPEB SETTLEMENT AT DOCKET NO. R-00049656?

A. The basis for the Company's claim is the Commission Order at Docket No. R-00049656 that approves paragraph 43 of the ALJ's Recommended Decision to amortize $1,005,345 over a 2-year period or $502,673 annually ($1,005,345 ÷ 2).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR THE AMORTIZATION OF OPEB SETTLEMENT AT DOCKET NO. R-00049656?

A. No. The Company's claim will result in an over recovery of the amortized amount because the two-year amortization expires April 14, 2007.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOWANCE FOR THE AMORTIZATION OF OPEB SETTLEMENT AT DOCKET NO. R-00049656?

A. I recommend an allowance of $39,479 annually for the amortization of the OPEB settlement at Docket No. R-00049656. The adjustment to the Company's claim is a reduction of $463,194 ($502,673-$39,479).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION REGARDING THE AMORTIZATION OF OPEB SETTLEMENT AT DOCKET NO. R-00049656?

A. The basis for my recommendation is the fact that this amortization will expire April 14, 2007 and that the rate proposal in this case has been suspended until March 2, 2007. When these rates become effective there will be 43 days remaining or a balance of $59,219 ($502,673 ÷ 365 x 43) to be recovered. I recommend amortizing this amount over a period of 18 months as that is the period that I have identified as the Company's frequency for filing rate cases. The

allowance of $39,479 annually ($59,219 ÷ 18 x 12) will allow the Company full recovery of the balance of this amortization.

OPEB PROPOSAL - R-00061493

Q. WHAT IS THE AMORTIZATION OF OPEB PROPOSAL - R-00061493?

A. The amortization of OPEB's proposed in this instant proceeding is the deferred balance that the Company claims it experienced between May 31, 2005 and the end of the FTY of January 31, 2007. The balance is claimed to be the difference between the former OPEB rate allowance and the annual OPEB cost for that period.

Q. WHAT IS THE COMPANY'S CLAIM FOR THE AMORTIZATION OF OPEB PROPOSAL - R-00061493?

A. The Company's claim for OPEB deferral in this case is a total of $1,642,905 as shown in the Company's Exhibit No. 104, Schedule 2 (benefits), p. 14.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM FOR THE AMORTIZATION OF OPEB PROPOSAL - R-00061493?

A. The basis for the Company's claim is the difference between the former OPEB rate allowance and the annual OPEB cost for the period May 31, 2005 through the end of the FTY in this case. Additionally, the Company is proposing to amortize the total amount over a 1-year period because the Company intends to file its next

rate case one year from the date the company filed this instant proceeding.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR THE AMORTIZATION OF OPEB PROPOSAL - R-00061493?

A. No. I do not agree with the amortization period.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE AMORTIZATION OF OPEB PROPOSAL - R-00061493?

A. I recommend an allowance of $1,095,270 annually. This recommendation results in an OTS adjustment of $547,635 to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION REGARDING THE AMORTIZATION OF OPEB PROPOSAL - R-00061493?

A. My recommended allowance of $1,095,270 is based on an amortization period of 18 months as that is the period that I have identified as the Company's frequency for filing rate cases ($1,642,905 ÷ 18 x 12). Amortizing this difference over the 18 month period will insure the appropriate recovery of the balance.

CO-OP ADVERTISING

Q. What is Co-op advertising?

A. Co-op advertising is a program by which utilities pay a portion of the advertising costs of developers, builders and contractors, who promote the use of natural gas

and natural gas appliances as the primary heating source for their housing developments. This incentive helps the company encourage builders to install natural gas in their developments and contractors to recommend conversion to natural gas appliances to their customers.

Q. HAS NFGD INCLUDED A CLAIM FOR CO-OP ADVERTISING IN THIS BASE RATE PROCEEDING?

A. Yes. The Company has budgeted an amount of $150,000 in the Future Test Year for Co-op advertising. See Response to OTS-RE-52 (OTS Ex. No.2, Sch. 3).

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THESE EXPENDITURES?

A. I recommend that NFGD's expenditures for Co-op advertising be denied as they pertain to promoting natural gas. This results in a reduction of $150,000.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. § Pa. C.S. 1316 (a) defines the parameters, by which advertising is considered a legitimate expense for ratemaking purposes, § 1316 (a) reads as follows:

> (a) General Rule – for purposes of rate determinations, no public utility may charge to its customers as a permissible operating expense for ratemaking purposes any direct or indirect expenditure by the Utility for political advertising, unless and only to the extent that the Commission finds that such advertising is reasonable and meets

one or more of the following criteria:

(1) is required by law or regulation;

(2) is in support of the issuance, marketing or acquisition of securities or other forms of financing;

(3) encourages energy independence by promoting the wise development and use of domestic sources of coal, oil or natural gas and does not promote one method of generating electricity as preferable to other methods of generating electricity;

(4) provides important information to the public regarding safety, rate changes, means of reducing usage of bills, load management or energy conservation;

(5) provides a direct benefit to rate payers;

(6) is for the promotion of community service or economic development.

The Co-op advertising expenditures included in this base rate proceeding promotes the use of natural gas and does not meet any of the six criteria established above.

Q. ARE YOU AWARE OF ANY COMMISSION DECISIONS DEALING WITH THE DISALLOWANCES OF THIS TYPE OF EXPENDITURE?

A. Yes. The Commission decided this issue at Pennsylvania Public Utility Commission v. Equitable Gas Company at Docket No. R-00901595, entered November 11, 1990.

Q. WAS IT FOUND IN THAT DECISION THAT RATEPAYERS BENEFIT FROM CO-OP ADVERTISING ACTIVITIES?

A. No. At 73 Pa. P.U.R., pp. 73-74, the commission states (1990):

> "Therefore, it is apparent that the gas company with which developer or builder engages in cooperative advertising is likely to be the gas company to which the home buyer will be connected for the duration of his or her ownership. The builder or developer may not choose a gas company on the basis of rates or service to the homeowner, the ultimate customer, but may choose a gas company on the basis of the size of the promotional allowance or advertising allowance offered. Thus, the cooperative advertising benefits the developer, the realtor, or the builder, but not *necessarily the ultimate ratepayers.*"

Q. IS THERE ANY OTHER JUSTIFICATION FOR THE DISALLOWANCE OF THE CO-OP ADVERTISING EXPENDITURES?

A. Yes. The public interest would dictate that in an era of deregulation a level playing field for all forms of energy should be paramount. Any costs incurred in the promotion of markets and customer growth should be below the line and a stockholder cost. To allow companies to recover these costs in base rates creates an uneven competitive environment to the company's advantage. The primary competition in a new development would be either electric or fuel oil. To the extent that an electric distribution company would have to provide an even greater incentive to promote an electric development would merely increase the cost of service. Advertising and promotions of this nature simply escalate the cost of service for both industries to the detriment of all energy customers.

GTI EXPENSE – DELTA FUND - RESEARCH AND DEVELOPMENT (R&D)

Q. WHAT IS GTI EXPENSE (DELTA FUND – RESEARCH AND DEVELOPMENT)?

A. Gas Technology Institute (GTI) is an independent technology organization. GTI was formed in 2000 from a merger of two research facilities, the Gas Research Institute (GRI) and the Institute of Gas Technology, after both faced funding challenges due to the phase out of a FERC approved R&D surcharge. The FERC transmission surcharge funded the GTI - Delta Fund for gas research until competition due to deregulation forced FERC to phase-out the mandatory funding in 1999 through 2004. GTI provides the following products and services:

- Performs contract research and development
- Provides technical services in areas related to energy and the environment
- Commercializes new energy related technology, directly and through subsidiaries
- Plans and manages technology development programs for the gas industry and other clients
- Provides education and training on technical and business topics related to energy and natural gas

Customers include energy industry companies, equipment manufacturers, government agencies and other organizations.

Q. WHAT IS NFGD'S CURRENT RATE ALLOWANCE FOR GTI EXPENSE?

A. In the Order at Docket No R-00049656 the Commission approved the recovery of $526,466 in Delta research funds including the qualification for deferred accounting under SFAS 71. NFGD uses these funds to continue in the sustaining member program (SMP) of GTI that funds various research projects. NFGD must submit an annual report of revenues and expenditures to the Commission. This report includes a summary of projects to which NFGD's research funds were applied.

Q. WHAT IS THE COMPANY'S CLAIM FOR GTI EXPENSE?

A. The Company's FTY claim for GTI Expense is $876,942 and is found in NFGD Exhibit No. 104, Schedule 2 (GTI), p. 34.

Q. WHAT IS THE BASIS FOR THE COMPANY'S GTI EXPENSE?

A. The Company calculated its FTY claim using the GRI surcharge at 1999 rates, before the FERC ordered phase out, and the demand and commodity volumes used in NFGD's 2006 1307(f) filing. The Company compared this result to the annualized amount of GTI expense approved per Docket No. R-00049656 of $526,466 and made a pro forma adjustment of $350,476 in order to arrive at the full GTI funding and FTY claim of $876,942.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND REGARDING GTI EXPENSE?

A. I recommend that the GTI expense remain at the level approved by the Commission at Docket No.R-00049656 of $526,466. This results in a reduction of $350,476 ($876,942-$526,466).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION REGARDING GTI EXPENSE?

A. My recommendation is based on the fact that the Company's expenditures for GTI expense have not reached the present approved level of $526,466 and is not projected to reach that level. The Company has actually expended $116,571 less than the $526,466 provided in rates as of June 30, 2006 and the Company's projected expenditures through September 2007 are only $391,000 (OTS Ex. No. 2, Sch. 4, p.1-3). Increasing the amount in rates under these circumstances presents an unnecessary burden on the ratepayers while the Company is essentially banking the cash collected.

DISTRIBUTION COMPONENT - PIPELINE INTEGRITY

Q. WHAT IS DISTRIBUTION PIPELINE INTEGRITY EXPENSE?

A. In December 2005 the "Integrity Management for Gas Distribution, Report of Phase I Investigations" was issued by the Joint Work/Study Groups that include representatives of the public, gas distribution pipeline industry, state pipeline safety and pipeline representatives and hazardous materials safety administration representatives. The report requires each system to:

- Develop and implement a written integrity management program,
- 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,
- Periodically report to a limited set of performance measures to regulators.

A final report is not expected to be issued until the end of 2006. Distribution pipeline integrity expense includes the estimated costs of implementing this report as it applies to the Company's distribution system.

Q. WHAT IS THE COMPANY'S INCREMENTAL CLAIM FOR PIPELINE INTEGRITY EXPENSE?

A. The Company's incremental claim is $1,040,497 as detailed on the Company's Ex. No. 104, Sch. 2 (Pipeline Integrity), p. 35.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM FOR PIPELINE INTEGRITY EXPENSE?

A. The Company based its claim on actual expenditures of $8,080,524 in fiscal 2005 that were spent on specific activities to achieve the high standards that the Company currently experiences. The Company then applied a projected percentage increase to determine the incremental expenses attributable to pipeline integrity. The incremental increase of $1,040,497 is estimated to achieve higher standards (OTS Ex. No. 2, Sch. 5, pp.1-4).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR PIPELINE INTEGRITY EXPENSE?

A. No. After reviewing the information the Company provided, I am of the opinion that the Company has not justified the incremental expenditures and therefore, I conclude that it is premature to approve increased expenditures at this time.

Q. WHAT DO YOU RECOMMEND REGARDING PIPELINE INTEGRITY EXPENSE?

A. I recommend that the incremental increase be rejected. This would result in an OTS reduction of $1,040,497 to the Company's FTY claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION REGARDING PIPELINE INTEGRITY EXPENSE?

A. My recommendation is based on the following:

- The report has not been issued.
- The performance requirements are not known.
- The Company's current level of performance has not been documented.

Therefore, a meaningful analysis of the current performance to required performance cannot be completed. Additionally, in informal discovery, OTS requested documentation of standards the Company is trying to improve, the current levels of performance and the expected levels of performance. To date OTS has not received a response.

FERC 2004 EXPENSE

Q. WHAT IS FERC ORDER 2004 EXPENSE?

A. FERC Order 2004 expense includes the estimated O&M costs associated with the implementation of the Federal Energy Regulatory Commission (FERC) Order No. 2004. This expense includes the additional costs to operate an independent

dispatch center which would be shared between the New York and the Pennsylvania division. FERC Order No. 2004 refers to the standards of conduct between regulated transmission providers and all their energy affiliates. The standards are intended to prevent transmission providers from giving their energy affiliates preferential treatment.

Q. WHAT IS THE COMPANY'S CLAIM FOR FERC 2004 EXPENSE?

A. The Company's FTY claim for FERC 2004 expense is $407,680 as detailed on the Company's Ex. No. 104, Sch. 2 (FERC 2004), p. 36.

Q. WHAT IS THE BASIS FOR THE COMPANY'S FTY CLAIM FOR FERC 2004 EXPENSE?

A. The Company's claim is based on a total expenditure of $1,300,000. Based on the ratio of throughput, the Pennsylvania division was allocated 31.36 percent of the total or $407,680 ($1,300,000 x 31.36%).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR FERC 2004 EXPENSE?

A. No.

Q. WHAT DO YOU RECOMMEND REGARDING FERC 2004 EXPENSE?

A. I recommend that the Company's claim be rejected. The resulting OTS adjustment is a reduction of $407,680.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION REGARDING FERC ORDER 2004 EXPENSE?

A. My recommendation is based on the fact that the Company filed a petition with FERC requesting a waiver to continue sharing a dispatch site. The Company has not received an answer and does not know when they will receive an answer to this petition for waiver of FERC Order No. 2004 (OTS Ex. No. 2, Sch. 6, p.1). Therefore, it is speculative to include this expense in rates.

ENERGY EFFICIENCY EXPENDITURES

Q. WHAT IS ENERGY EFFICIENCY EXPENDITURES?

A. The energy efficiency expenditures requested in O&M expenses include the costs to implement the proposed "Save Today, Save Tomorrow" media campaign which is the Company's proposed outreach effort to promote enhanced energy efficiency. This expenditure coincides with the implementation of the proposed new tariff rider, Rider I, Enhanced Energy Efficiency Cost Recovery Rider.

Q. WHAT IS THE COMPANY'S CLAIM FOR ENERGY EFFICIENCY EXPENDITURES?

A. The Company's FTY claim for energy efficiency expenditures is $1,800,000 as detailed on the Company's Ex. No. 104, Sch. 2 (Energy Efficiency), p. 38.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR ENERGY EFFICIENCY EXPENDITURES?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR ENERGY EFFICIENCY EXPENDITURES?

A. I recommend that the Company's claim be denied. The resulting OTS adjustment is a reduction of $1,800,000.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION REGARDING ENERGY EFFICIENCY EXPENDITURES?

A. My recommendation is based on the associated recommendation of OTS witness Kubas in OTS Statement No. 3. Mr. Kubas has recommended that the EEE rider be denied. Therefore, the promotional campaign included in this claim should also be denied. Additionally, the Company currently spends 62.5 percent or $371,278 of its advertising budget on conservation as detailed in the Company's Ex. No. 4, Sch. 8, p. 2.

MERCHANT FUNCTION CHARGE (MFC)

Q. WHAT IS THE MERCHANT FUNCTION CHARGE?

A. The Merchant Function Charge is a proposal that allows an amount of non-gas costs that could be associated with the purchase gas function, to be recovered through a percentage increase in the PGC rate. The two cost components the Company proposes to be included in the determination of the MFC are storage working capital costs and a portion of uncollectible accounts attributable to PGC costs.

Q. WHAT IS THE COMPANY'S RECOMMENDATION REGARDING THE MERCHANT FUNCTION CHARGE?

A. The Company has calculated the current MFC percentages for residential and non-residential customers in Ex. No. 111, Sch. 4, p. 4. The Company recommends that this percentage be applied to the Natural Gas Supply Charge and the Gas Adjustment Charge and therefore, the rate would change anytime the gas costs change. The MFC percentage would be recalculated at each base rate proceeding.

Q. WHAT IS THE BASIS FOR THE COMPANY'S RECOMMENDATION REGARDING THE MERCHANT FUNCTION CHARGE?

A. The Company is proposing the MFC as a catalyst for competition by unbundling rates into delivery and purchased gas components. Only customers that choose to receive natural gas supply service from the Company are charged the Company's gas supply charges. All customers are charged the Company's delivery rate. The Company chose to include the two cost components because they believe that these costs have a direct relationship to the Company's role as a merchant of natural gas supplies.

Q. DO YOU AGREE WITH THE COMPANY'S RECOMMENDATION REGARDING THE MERCHANT FUNCTION CHARGE?

A. No.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE MERCHANT FUNCTION CHARGE?

A. I recommend that the Company's proposed MFC be denied.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION REGARDING THE MERCHANT FUNCTION CHARGE?

A. My recommendation to reject the MFC is based on several factors. First, the proposal is inadequate. Second, the proposal is self-serving. Third, the proposal is illegal. Fourth, the proposal is premature.

Q. WHY DO YOU BELIEVE THE PROPOSAL IS INADEQUATE?

A. As the Company points out, the Commission is concerned about the limited number of Natural Gas Suppliers (NGS) and is exploring ways to improve competition. One of those ways is to levelize the playing field in the price to compare so that the price to compare includes all costs related to natural gas procurement and sales. Of all the costs that should be included the Company has isolated only two components.

Q. WHAT COSTS SHOULD BE INCLUDED IN THE PIECE TO COMPARE AND REMOVED FROM THE DISTRIBUTION CHARGE?

A. In addition to the two costs claimed, the following costs potentially should be included; billing costs, gas supply related customer service costs, a percentage of credit and collection costs, information management costs related to gas procurement, compliance with consumer protection and notifications related to gas commodity costs, customer choice education, legal expenses for 1307(f) filings, FERC related costs and a percentage of Company overheads and corporate

allocations.

Q. WHY DO YOU SUPPOSE THE COMPANY ISOLATED ONLY ON WORKING CAPITAL REQUIREMENTS AND UNCOLLECTIBLES?

A. Only the Company can provide their motivation; however, it would appear that the Company saw an opportunity to capitalize on the Commissions' concerns and guarantee more of their revenue requirements. Gas costs are volatile and impact these two items the most of all the items listed. Including them in the MFC protects the Company against potential increase while reducing the Company's risk exposure. The Company excluded the other items because they would increase the Company's risk of under recovery of non-gas costs. The Company's proposal is one sided and self serving.

Q. WHY IS THE PROPOSAL ILLEGAL?

A. I am advised by Counsel that the Company's proposal to adjust uncollectibles violates the intent of Chapter 14.

Q. WHY DO YOU BELIEVE THE PROPOSAL IS PREMATURE?

A. By the time the Company files it's next base rate case, whether in 12 or 18.75 months, the Commission will have concluded the competition investigation. At that time, the Company can make a filing proposal that encompasses the Commission's recommendations and is more balanced between the interests of the

Company and its ratepayers.

PURCHASE OF RECEIVABLES (POR) PROGRAM

Q. WHAT IS THE PURCHASE OF RECEIVABLES OR POR PROGRAM?

A. In order to enhance the potential for competition for natural gas supplier (NGS) service on its system, the Company has proposed a pilot program for the purchase of NGS's receivables.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL REGARDING THE POR PROGRAM?

A. The Company proposes to purchase the accounts receivable, of specified customer classes, of NGS's that utilize the Company's standard billing service. The receivables will be purchased at the same discount as the percentage for the MFC. The current residential account POR discount will be 3.07%. The current non-residential POR discount will be 0.81%. The Company will purchase the receivables, without recourse. The Company will remit payment to the NGS for purchased receivables on the 23rd day following the issuance of the bill to the customer. The Company will administer the consumer protections including termination procedures to NGS customers in the same manner as the Company's customers including assessing late payment charges, and customer deposits.

Q. DO YOU AGREE WITH THE CONCEPT OF A POR PROGRAM?

A. Yes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE POR PROGRAM?

A. OTS agrees with the POR program conceptually. However, I am not sure that the Company has dealt with all ratemaking implications and therefore, OTS reserves the right to deal with this in subsequent rate cases.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I am of the opinion that it is appropriate for the Company to initiate programs to determine if interest in competitive alternatives of natural gas supply can be increased in the Company's service territory. The POR pilot program may encourage NGS to compete for the Company's customers if the risk of uncollectible expense is minimized. Purchasing the receivables at a discount would reduce the risk for the Company that the NGS would only market to the Company's non-payment troubled customers.

CASH WORKING CAPITAL

Q. WHAT IS CASH WORKING CAPITAL (CWC) ALLOWANCE FOR RATEMAKING PURPOSES?

A. CWC is the amount of funds necessary to operate a utility during the interim between the rendition of service, including the payment of related expenses and the receipt of revenue in payment for services rendered. A lead/lag study measures the differences in time between: (1) the time services are rendered until payment of those services is received; and (2) the time between when a utility has incurred an expense and the actual payment of the expense.

Q. WOULD YOU EXPLAIN THE DIFFERENCE BETWEEN THE RATEMAKING AND ACCOUNTING CONCEPTS OF WORKING CAPITAL?

A. Yes. Outside the arena of utility ratemaking, accountants define working capital as the difference between current assets and current liabilities, which is a measure of a business' liquidity at a given point in time. On the other hand, the ratemaking concept defines CWC as the amount of capital that a utility requires to cover the gap between the payment of operating expenses and taxes and the receipt of revenue from utility ratepayers.

Q. WHAT IS THE COMPANY'S CLAIM FOR CWC?

A. The Company's total claim for CWC is $40,371,000 as shown in NFGD Ex. 108, Sch. 4, p. 2. The major components that comprise the Company's total CWC claim are as follows:

CWC from O&M and Taxes	$ 40,382,000
Less Adjustments for:	
Offset for Long-Term Interest	297,000
Offset for Short-Term Interest	(286,000)
	11,000
Total CWC Claim	$ 40,371,000

Q. WHAT IS THE COMPANY'S CWC CLAIM FOR O&M EXPENSES AND TAXES?

A. The Company's CWC claim for O&M expenses and taxes is $40,382,000 based on a lead/lag study for the twelve months ended January 31, 2006 as shown in NFGD Exhibit No. 108, Schedule 4, pp. 5-7.

Q. DO YOU AGREE WITH ALL OF THE COMPONENTS OF THE LEAD LAG STUDY FOR O&M AND TAXES?

A. No. I disagree with the Company's claimed lag for pension fund, goods and services and PURTA.

Q. WHAT ADJUSTMENTS ARE YOU PROPOSING?

A. I am proposing three adjustments to the Company's claimed CWC requirement for operations and maintenance (O&M) expenses and taxes. My recommendations include adjustments to the Company's lag day claims for pension fund expense, goods and services expense and PURTA.

Q. WHAT IS PENSION FUND EXPENSE?

A. Pension fund expense includes cash contributions that the Company actually pays to a trust established by a company to pay retirement benefits to eligible employees.

Q. WHAT IS THE COMPANY'S CLAIMED LAG FOR PENSION EXPENSE?

A. The Company has claimed a lag of (131.90) days for pension expense as shown in NFGD Ex. 108, Sch. 4, p. 5.

Q. HOW DID THE COMPANY CALCULATE ITS CLAIMED LAG OF (131.90) FOR PENSION EXPENSE?

A. The Company's lag calculation is detailed at NFG-2-37, Ex. No. 8-D, p. 1. The Company's calculation is based on accrued liabilities which they treated as payments and which were determined by allocating a portion of the yearly liability to each month. Additionally, each month was treated as the service period and a midpoint of the service period was determined. The lag days were calculated by

comparing the midpoint of each service period (month) to an accrued date. The lag days times the accrued monthly expense determined the weighted dollar days. The weighted lag days for the TME January 2006 were calculated by adding the weighted dollar days for each month divided by the total or annual liability. Additionally, the Company included an expense amount of $654,096 for deferred amortization of pension expenses. This amount was determined by allocating a portion of the annual deferred amount of $1,080,974 approved at Docket No. R-00038168 and revised at Docket No. R-00049656 to begin April 15, 2005 as an accrued expense in the same way explained above for the annual pension liability amount. After the completion of both calculations the Company arrived at their claim of (131.9) lead days.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No. The Company's calculation is flawed and should be rejected.

Q. WOULD YOU EXPLAIN WHY THE COMPANY'S CALCULATION IS FLAWED?

A. The Company's calculation is flawed in the following ways:

1. The Company's use of accrued liability ignores the basic premise of a lead lag study.

2. The lag days are incorrectly calculated based on a false premise.

3. The lag calculation includes the deferred amortization amounts.

Q. WOULD YOU ELABORATE ON YOUR FIRST CHARGE THAT THE COMPANY'S CALCULATION IGNORES THE BASIC PREMISE OF THE LEAD/LAG STUDY?

A. Yes. As I stated earlier in my testimony, a lead /lag study measures the time between when a utility has incurred an expense and the actual payment of that expense. I emphasize the word actual because the payment amounts utilized in the Company's lag calculation are not the actual payments to the pension fund but bookkeeping accruals allocating the annual payment on a monthly basis. Cash payments were not made in the amounts listed therefore, the Company's calculation does not properly calculate the cash requirements of the Company but instead uses a hypothetical calculation of bookkeeping charges.

Q. YOU STATED THAT THE LAG DAYS ARE CALCULATED BASED ON A FALSE PREMISE. WOULD YOU EXPLAIN WHAT YOU MEAN BY THAT STATEMENT?

A. Yes. The Company has calculated each month's lag to the midpoint of a monthly liability, based on the premise that the funding is required on a monthly basis. However, the Pension funding is an annual expense. The Company does not actually fund the pension expense on a monthly basis. The total amount of each actual payment should have been lagged to the mid-point of the plan year, which is July 1 through June 30.

Q. YOU STATED THAT THE COMPANY'S LAG CALCULATION INCLUDES AN EXPENSE AMOUNT FOR DEFERRED AMORTIZATION OF PENSION EXPENSE. PLEASE EXPLAIN WHY THIS SHOULD NOT BE INCLUDED IN THE CALCULATION.

A. The deferred amortization amounts were approved in the settlement at Docket No. R-00038168 and revised at Docket No. R-00049656 to begin recovery in rates that went into effect on April 15, 2005. The Commission approved the recovery in rates of $4,323,897 to be amortized over a 4-year period. The Commission therefore, approved the return of the funds not a return on the funds. Since CWC is part of a Company's rate base on which a Company's receives a rate of return, therefore, this amortization should not be included in this lead/lag study. Additionally, this amortization is not a cash item.

Q. WHAT IS YOUR RECOMMENDATION FOR PENSION EXPENSE LAG DAYS?

A. My recommendation is a lag of 60.22 days. My calculation is detailed in OTS Ex. No. 2, Sch. 7, p. 1.

Q. PLEASE EXPLAIN YOUR PENSION LAG CALCULATION?

A. The lead/lag study is for the twelve months ended January 31, 2006. I started by listing all payments to the pension fund during that twelve- month period that were provided in the Company's response to OTS-RE-165 (OTS Ex. No. 2, Sch. 7, p.

2). I then lagged each payment to the midpoint of the plan year that the Company stated that the payment applied to (OTS Ex. No. 2, Sch. 7, p. 1). The result was a weighted lag of 60.22 days.

Q. WHAT ARE GOODS AND SERVICES AS IT APPLIES TO A RATEMAKING LEAD/LAG STUDY?

A. Goods and services include O&M expenses of a miscellaneous nature that are not included in any other category of the lead/lag study.

Q. WHAT ADDITIONAL ITEMS DID NFG INCLUDE IN THE GOODS AND SERVICES LEAD/LAG STUDY?

A. NFG included items such as payroll, benefits, taxes and capital purchases.

Q. WHAT IS THE COMPANY LAG CLAIM FOR GOODS AND SERVICES?

A. The Company's claimed lag for goods and services is 10.58 days as detailed in NFG-2 37, Ex. No. 8-D, pp. 1-72.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED LAG FOR *GOODS AND SERVICES?*

A. The Company witness Truitt in St. No. 5, at pages 12-14 testified to the basis for the Company's claimed lag for goods and services. Ms. Truitt states that the Company examined 3,592 invoices that were paid during the test period. The

Company created this sample by conducting a query of the Company's accounts payable transactions for each month during the historic test year. Each month was analyzed to exclude transactions less than $1,000 and greater than $200,000, expenses that were included in other lag analysis, prepayment items and uncollectible expenses. Witness Truitt explains that the Company then determined a service period from dates within the Company's accounting system. A midpoint of service was established and then compared to the payment date to develop an actual lead or lag for each transaction. For each transaction, the expense amount was then multiplied by the lead/lag to create a weighted cost. The expense and weighted cost were accumulated for all transactions for each month and compiled for the historic twelve months ended January 31, 2006 to create an expense lag of 10.58 days as shown in the Company's Ex. No. 8, Sch. 4, p. 5.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIMED LAG OF 10.58 DAYS FOR GOODS AND SERVICES?

A. No. I do not agree with the Company's methodology for determining the service period for each transaction. Additionally, OTS has observed that the Company has made numerous errors in the analysis of each month's invoices to determine if the invoice should be included in the lead/lag study. In my judgment, both of these issues have resulted in a lag claim for goods and services that is unrealistically low.

Q. PLEASE EXPLAIN THE COMPANY'S METHODOLOGY FOR DETERMINING THE SERVICE PERIOD FOR EACH TRANSACTION.

A. The Company used information readily available from the accounts payable transaction records to determine the service period. The specific records that the Company used are the check date and the invoice date. The Company compared the invoice date to the check date, considered this the service period and added them together then divided by two to determine the midpoint of the service period. For example if the invoice date was 2/23/2005 and the check date was 2/25/2005, the service period is the two days elapsed between these dates and the midpoint of the service period is 2/24/2005. The Company then compared the midpoint of the service period with the check date to establish the difference of "1" as the lag days for this transaction.

Q. WHY DO YOU DISAGREE WITH THIS METHOD OF DETERMINING THE SERVICE PERIOD?

A. I disagree with this method of determining the service period because the invoice date is not usually indicative of the time between when a utility has incurred an expense and the actual payment of the expense that is defined as the service period. In many instances, a Company receives an invoice for services or goods that were provided the prior month. For example, the Company's response to OTS-RE-59 (OTS Ex. No. 2, Sch. 7, pp. 3-4), Section B, relates to Inter Company Billings in February of 2005, for which the Company has calculated a lag of 1 day.

On page 4, the Company explains that inter company billings are related to the payment of inter company payable balances, which are paid in full on a monthly basis. The Company refers to NFG Ex. No. 4, Sch. 11 for the service agreement. On page 10 of the service agreement, Article V – Billing Practices, the agreement states that after the last day of each month, or such period agreed upon by the respective companies, a billing shall be rendered for the services and expenses for such period. The Company has included two to three inter company billing accounts payable transactions in the sample for each of the twelve months submitted. The lag days that the Company computed range from zero to four days (NFG-2-37, Ex. No. 8-D, pp. 11-72). Clearly, if these billings are for a months worth of goods and services a lag of 15 days is more reasonable. Another example is found in the Company's response to OTS-RE-64, section A (OTS Ex. No. 2, Sch. 7, p. 6). This invoice is from Price Waterhouse Coopers LLP dated March 18, 2005 and paid on March 28th for 2005 audit fees and expenses. The Company response states that the payment is for a progress bill related to accounting services rendered for the fiscal year ending September 30, 2005. The Company calculated a lag of 5 days. Again, if this is a progress payment they are usually at least a month or some period of time prior to the invoice date. Additionally, the Company has admitted in response to numerous interrogatories that many items are monthly, quarterly and annual payments. None of these service periods are reflected in the lags that the Company has calculated.

Q. PLEASE EXPLAIN THE NUMEROUS ERRORS YOU BELIEVE THE COMPANY HAS MADE IN ITS ANALYSIS OF INVOICES THAT SHOULD NOT BE INCLUDED IN THE LEADLAG STUDY FOR GOODS AND SERVICES.

A. Based on my analysis of the twelve months of accounts payable transactions that the Company included in the category goods and services lag calculation, I dispute the inclusion of 312 transactions (OTS Ex. No. 2, Sch. 7, pp. 7-12). The disputed transactions can be summarized into categories. First, payments for expenses are included in other areas of the lead/lag studies, such as payroll, benefits and taxes. They constitute duplicative CWC claims. Second, payments that are for purchases of capital items. Third, payments for expenses that are considered "below the line" expenses, such as Co-op advertising, employee loans, donations, memberships, and Company functions. Fourth, transactions that represent Company errors, such as duplicate entries, data entry errors, voids, and stopped payments.

Q. DO YOU HAVE ANY OTHER REASON TO DISPUTE THE COMPANY'S LAG DAY CLAIM OF 10.58 DAYS FOR GOODS AND SERVICES?

A. Yes. Based on my research of the miscellaneous/other lag day claims presented in 10 recent gas, electric and water company category one rate cases, the Company's corresponding claim for goods and services of 10.58 lag days is not within the normal range experienced by the sample group (OTS Ex. No. 2, Sch. 7, pp. 1-3).

The average claim for other invoices in the 10 cases is 35.42 lag days. The range is 21.56 to 57.91.

Q. WHAT IS YOUR RECOMMENDATION FOR THE GOODS AND SERVICES LAG DAYS?

A. I recommend 30 lag days for goods and services.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED LAG OF 30 DAYS FOR GOODS AND SERVICES?

A. The basis for my recommendation is the premise that usually a Company receives goods and services prior to the Company's receipt of an invoice and that usually a Company is given payment terms that can vary from "upon receipt" to "net 30 days". The recommended 30-day lag reflects an average midpoint of service period of 15 days and an average payment date that occurs 15 days later. Therefore, the lag of 30 days is determined by comparing the midpoint of the service period to the payment date.

Q. DID YOU ATTEMPT TO CALCULATE A GOODS AND SERVICES LAG BASED ON YOUR ANALYSIS OF THE INFORMATION THAT THE COMPANY PROVIDED IN NFG-2 37, EXHIBIT NO. 8-D, pp. 1-72.

A. Yes. In an effort to establish the appropriate service periods for each transaction, OTS submitted numerous interrogatories to the Company and also pursued this

issue during an informal discovery session. Based on comments listed in the description (Descr) column of the Company's Exhibit No. 8-D, pp. 11-72, OTS tried to verify the service periods of numerous transactions. The Company stated that "you can't go by that description" indicating that the descriptions were an unreliable reference in determining the service period. Therefore, since we did not have adequate information to properly determine the service periods for each transaction, I recommended the 30-day lag for goods and services as detailed above.

Q. WHAT IS PUBLIC UTILITY REALTY TAX?

A. PURTA is the common name for the Pennsylvania Public Utility Realty Tax. PURTA is imposed on all public utilities furnishing public utility service under the jurisdiction of the Pennsylvania Public Utility Commission.

Q. WHAT ARE THE PURTA FILING REQUIREMENTS AND RATES?

A. A tentative payment for PURTA is due on May 1st of the taxable year. The tax return is filed on May 1st of the following year. The Department of Revenue bills the utility for the final payment on August 1st, 92 days after the filing of the PURTA tax return. The final payment is due 45 days later on September 15th. The tax rate is a floating rate calculated annually by the Department of Revenue. The tentative tax payment must equal at least 90% of the final tax due.

Q. WHAT IS THE COMPANY'S CALCULATED LAG FOR PURTA?

A. The Company calculated a PURTA lag of (36.53) days (Reference NFG-2 37, Ex. No. 8-D, Page 1 of 1).

Q. HOW DID THE COMPANY CALCULATE ITS LAG OF (36.53) DAYS?

A. The Company began by calculating the average tentative payment as a percentage of the total tax and the average final payment as a percentage of total tax. This analysis was based on the actual PURTA payments made over the 10 year period 1995-2005. On average, the Company has prepaid 81.41% of their liability as a tentative payment and made a final payment of 18.59%. The Company assumed tax year of 2005 (PURTA taxes are filed on a calendar basis) and lagged the May 1 tentative payment and the September 15 final payment to the mid-point of calendar year 2005. The net result was a claimed lag of (36.53) days.

Q. ARE YOU IN AGREEMENT WITH THE COMPANY'S PURTA TAX LAG CALCULATION?

A. No. The Company's lag calculation is in error because the Company's final payment relative to calendar 2005, would not be due until September 15 of 2006. The correct lag associated with the final payment would be calculated from the mid-point of 2005 (July 1) to September 15, 2006 not September 15, 2005.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommended a net PURTA tax lag of (32.3) days, based on the correct statutory payment requirements.

Q. HOW DID YOU CALCULATE THE PURTA TAX LAG?

A. The PURTA tax lag was calculated as follows:

Date	%Tax	Days	Lag Days
5/1	81.41	(61.0)	(49.7)
9/15	18.59	441	82.0
			(32.3)

I utilized the minimum tentative prepayment percentage of 90 percent as based on the statutory due date of May 1st. I have also calculated the lag associated with the final payment due on September 15th.

Q. WHAT IS THE NET EFFECT OF ALL OF THE OTS PROPOSALS FOR THE CWC ALLOWANCE FROM O&M AND TAXES?

A. OTS Ex. No. 2, Sch. 7, p. 14, details the net effect of the OTS recommended lag days for pension, goods and services and PURTA and calculates the OTS CWC requirement for O&M taxes. The following is a summary of the recommended CWC allowance:

CWC from O&M and Taxes	$ 36,679,000
Less Adjustments for:	
Offset for Long-Term Interest	297,000
Offset for Short-Term Interest	(286,000)
	11,000
Total CWC Allowance	$ 36,668,000

Q. DOES YOUR RECOMMENDED CWC ALLOWANCE OF $36,668,000 REPRESENT A FINAL RECOMMENDED ALLOWANCE FOR CWC?

A. No. All adjustments to the Company's claims for revenues, expenses, taxes and rate base must be consistently brought together in the ALJ's Recommended Decision and, again, in the Commission's Final Order. This process, which is known as "iteration", effectively prevents the determination of a precise calculation until such time as all adjustments have been to the Company's claim.

O&M EXPENSE REDUCTION- FEDERAL SUBSIDY FOR RETIREE PRESCRIPTION DRUG PLAN

Q. WHAT IS THE FEDERAL SUBSIDY FOR RETIREE PRESCRIPTION DRUG PLAN?

A. Under the Prescription Drug, Improvement and Modernization Act of 2003, NFGD is expected to receive a subsidy in the form of a cash payment that is exempt from federal income taxes. NFGD is eligible for this subsidy as long as

they continue to provide prescription drug benefits to retirees that are at least actuarially equivalent to Medicare Part D (see OTS Ex. No. 2, Sch. 8, p.1-2).

Q. HAS THE COMPANY CONSIDERED THIS SUBSIDY WHEN DEVELOPING THE REVENUE REQUIREMENT IN THE INSTANT PROCEEDING?

A. No. The Company has not provided any proof that this subsidy was considered when developing the revenue requirement in this instant proceeding.

Q. WHAT IS THE AMOUNT OF THE SUBSIDY?

A. The Company's consultant, Mercer Human Resource Consulting, projects that the Pennsylvania Division of NFGD will receive $160,000 for the TME December 31, 2006.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE COMPANY'S SUBSIDY?

A. Yes. I recommend that the Company's O&M expenses be reduced by $160,000.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The basis for my recommendation is the fact that the ratepayers are paying for the retiree's prescription drug plan since all OPEB expenses are included in rates.

This subsidy is a direct result of the Company providing retirees with prescription drug benefits. Therefore, ratepayers should receive rate relief in the form of a reduction to the Company's claimed expenses for O&M.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to submit supplemental testimony as the Company and other parties provide interrogatory responses during the course of this proceeding.

APPENDIX A

Janet M. Markovich

Applicable Educational and Professional Background

Education:

Master of Science in Business Administration, Concentration in Finance,
St. Joseph's University, Philadelphia, Pa. 1994
Bachelor of Science in Business Administration, Elmhurst College, Elmhurst Ill. 1981

Additional Education:

NARUC Utility Rate School - October 2004
The Many Voices of Wall Street – October 2004
Telephony and Telecommunications – December 2004

Business Experience:

Commonwealth of Pennsylvania
Public Utility Commission
Office of Trial Staff
Fixed Utility Financial Analyst 2004 - Present
Responsible for performing studies and analysis of revenues and expenses and other related financial and economic data as required to process rate increase requests, 1307 (f) purchased gas cost filings and general tariff revisions.

Commonwealth of Pennsylvania
Department of Corrections–
Budget Analyst I and II 2003-2004
Responsible for coordinating the General Fund section of the business office as required to monitor spending, collect data and generate budgets, re-budgets and various projections.

Borough of Minersville
Borough Manager 1997-2000
Responsibilities under the direction of the Borough Council included the supervision of the business office, and the coordination of the activities of the following departments:

Streets, Sewer Treatment Plant and Collection System, Code, Health, and Grant Administration. Addition responsibilities included the development and administration of budgets for the General, Water, and Sewer Funds.

Pepperidge Farm, Inc
Plant Manager 1982-1991
As Resident Executive, my responsibilities included all activities related to the manufacture and distribution of fresh and frozen bakery, cookie and cracker products at facilities in Downers Grove, Illinois and Lakeland, Florida. Major responsibilities included the development and administration of plant operating and capital budgets and the coordination of the following functions: Engineering, Maintenance, Production, Distribution, Accounting, Purchasing, Human Resources, and Information Systems.

Assisted in the following Cases :

Borough of Quakertown – Rate Case – R-00049555
National Fuel Gas Distribution – Rate Case – R-00049656
TW Phillips Gas and Oil Co. – 1307(f) – R- 00040059
Myers Gas Company – Rate Case – R-00050259
PECO Energy Company – 1307(f) – R – 00050537
UGI Utilities, Inc. Gas Division – 1307(f) – R – 00050539
Trigen- Philadelphia Energy Corporation – R – 00050781

Participated in the following Cases:

City of Bethlehem Water Fund – Rate Case - R-00050671
Wonderview Water Inc. – Rate Case - R-00050659
Meadows Sewer Co. – Rate Case – R-00050672
Wilcox Water Co. – Rate Case – R-00050781
Lancaster Water Fund – Rate Case – R-000501167
City of Dubois – Water Bureau – R-00050671

Testified in the following Cases:

City of Lancaster Sewer Fund – Rate Case – R-00049862
Mesco Inc. – Rate Case – R- 00050678
TW Phillips 1307(f) – R-00051134
Aqua Pa – Rate Case – R-00051030
Equitable Gas Company 1307 (f) – R-00061295
Duquesne Light Company – R-00061346

OTS Exhibit No. 2
Witness: Janet M. Markovich

ORIGINAL

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

NATIONAL FUEL GAS DISTRIBUTION COMPANY

Docket No. R-00061493

Exhibit to Accompany

the

Direct Testimony

of

Janet M. Markovich

Office of Trial Staff

Concerning:

Operations & Management Expenses
Cash Working Capital
Merchant Function Charge
POR Pilot Program

R-00061493
OTS-RE-18
Witness: Friedrich-Alf
Page 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OTS RE INTERROGATORIES

18. Reference Exhibit No. 104, Schedule 2 (Rate Case) p. 27.

A. Provide the supporting calculation of the additional legal services of $305,304.

B. Provide the supporting calculation of each of the four items comprising the average expense of $535,889.

C. Provide copies of all invoices received to date related to rate case expense.

D. Is the Company proposing a one year normalization of rate case expense?

Response

A. R-942991 was the last base rate case that National Fuel litigated. Distribution spent $396,755 for legal expertise which equates to $733,802 in 2007 dollars. R-0003168 and R-00049656 were both settled cases in which $435,786 and $304,471 were spent on legal expertise. These expenditures were brought forward to 2007 dollars and averaged to calculate $428,498. The $305,304 is the difference between the $733,802 to fully litigate and $428,498 the average when settled.

B. Docket No. R-00038168 was filed on April 13, 2003 and effective on January 15, 2004. Below is a calculation of the costs associated with filing R-00038168.

Expertise	Total Dollars	At 1/2005	1/2006	1/2007
Rate of Return	93,319	96,049	99,051	101,651
Lead/Lag	4,226	4,349	4,485	4,603
Depreciation	19,398	19,963	20,587	21,128
Legal	435,786	452,844	485,652	520,837

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Docket No. R-00049656 was filed on September 15, 2004 and effective on April 15, 2005. Below is a calculation of the costs associated with filing R-00049656.

Expertise	Total Dollars	1/2006	1/2007
Rate of Return	69,576	70,905	72,766
Lead/Lag	0	0	0
Depreciation	13,828	14,260	14,634
Legal	304,471	313,449	336,158

Below is a summary of the calculation of the average

Expertise	R-00038168 in 2007 Dollars	R-00049656 in 2007 Dollars	Average of both cases in 2007 Dollars
Rate of Return	101,651	72,766	87,209
Lead/Lag	4,603	0	2,302
Depreciation	21,128	14,634	17,881
Legal	520,837	336,158	428,498

C. Attached are invoices associated with R-0061493 paid through June 28, 2006.

D. Rate case expense represents the cost of regulation for placing new base rates in effect. Distribution anticipates that, due to its budget for construction of non-revenue producing plant, its continuing loss of load, and increases in operating expenses and capital costs, it will be filing base rate cases on an annual basis. Therefore the cost to institute the single year should be recovered in a single year.

National Fuel Gas Distribution Corporation
Pennsylvania Division
OTS Uncollectible Expense Adjustment
to the Twelve Months Ending January 31, 2007

Development of Uncollectible Expense
based upon the latest 36 months average of net write-offs

		Company Claim	OTS Recommendation	OTS Recommendation Adjustment
		$	$	$
a.	Net Write-off - 36 months ended January 31, 2006	12,511,749	14,908,582	
b.	Divided by Gross Revenue - 36 months ended January 31, 2005	628,962,848	886,108,247	
c.	Calculated net write-off factor	0.019892668	0.01682479	
d.	Gross revenue for the twelve months ending January 31, 2007	424,136,066	424,136,066	
e.	d * c = projected uncollectible accounts expense for the 12 mos. ending January 31, 2007	8,437,198	7,135,999	1,301,199

National Fuel Gas Distribution Corporation
Pennsylvania Division
OTS Uncollectible Expense Adjustment
to the Twelve Months Ending January 31, 2007

Development of Uncollectible Expense
based upon the latest 36 months average of net write-offs

Month/Yr	Gross Revenue	Month/Yr	Write-offs Less Taxes	Recoveries	Note 1 Net Write-offs	LIRA Write-offs	Net Write-offs
	$		$	$	$		
Feb-02	31,253,154	Feb-03	270,072	137,875	132,197	27,111	105,086
Mar-02	30,573,040	Mar-03	283,340	99,941	183,399	22,029	161,370
Apr-02	25,881,264	Apr-03	1,227,157	116,809	1,110,348	20,203	1,090,145
May-02	17,673,971	May-03	686,807	84,178	602,629	17,894	584,735
Jun-02	11,971,911	Jun-03	512,374	57,399	454,975	29,817	425,158
Jul-02	7,493,977	Jul-03	425,112	61,512	363,600	29,475	334,125
Aug-02	7,451,504	Aug-03	333,926	74,459	259,467	31,230	228,237
Sep-02	8,716,195	Sep-03	279,504	72,383	207,121	30,624	176,497
Oct-02	11,347,800	Oct-03	258,272	103,604	154,668	33,348	121,320
Nov-02	22,278,381	Nov-03	266,934	60,159	206,775	26,411	180,364
Dec-02	37,651,282	Dec-03	201,524	95,142	106,382	21,016	85,366
Jan-03	44,852,920	Jan-04	230,296	104,726	125,570	18,614	106,956
Feb-03	49,905,823	Feb-04	303,996	112,028	191,968	22,696	169,272
Mar-03	45,342,280	Mar-04	450,217	134,561	315,656	30,771	284,885
Apr-03	29,285,692	Apr-04	1,387,699	140,792	1,246,907	30,689	1,216,218
May-03	19,052,186	May-04	1,058,426	80,512	977,914	65,504	912,410
Jun-03	12,516,095	Jun-04	884,588	94,409	790,179	66,943	723,236
Jul-03	7,943,580	Jul-04	726,165	72,647	653,518	57,965	595,553
Aug-03	8,340,148	Aug-04	468,517	88,221	380,296	46,050	334,246
Sep-03	9,159,734	Sep-04	389,921	131,548	258,373	53,024	205,349
Oct-03	15,486,604	Oct-04	527,135	120,016	407,119	82,138	324,981
Nov-03	21,835,194	Nov-04	250,633	98,187	152,446	27,867	124,579
Dec-03	37,114,504	Dec-04	219,818	116,479	103,339	26,527	76,812
Jan-04	50,180,605	Jan-05	301,305	133,715	167,590	27,673	139,917
Feb-04	56,370,825	Feb-05	369,644	137,537	232,107	27,080	205,027
Mar-04	43,212,342	Mar-05	606,250	90,792	515,458	34,776	480,682
Apr-04	34,765,582	Apr-05	1,931,388	102,200	1,829,188	55,953	1,773,235
May-04	19,250,258	May-05	1,367,039	113,231	1,253,808	76,934	1,176,874
Jun-04	11,101,438	Jun-05	1,092,246	91,631	1,000,615	103,679	896,936
Jul-04	9,356,538	Jul-05	791,076	92,617	698,459	83,280	615,179
Aug-04	9,021,156	Aug-05	582,095	125,308	456,787	52,263	404,524
Sep-04	9,352,859	Sep-05	479,865	133,459	346,406	66,780	279,626
Oct-04	14,284,826	Oct-05	350,824	159,785	191,039	55,963	135,076
Nov-04	23,018,627	Nov-05	321,377	154,191	167,186	49,225	117,961
Dec-04	40,074,667	Dec-05	284,848	236,404	48,444	29,966	18,478
Jan-05	52,991,285	Jan-06	327,670	200,723	126,947	28,780	98,167
Total	886,108,247		20,448,060	4,029,180	16,418,880	1,510,298	14,908,582

Note 1: Net Write-offs = Write-offs less taxes - Recoveries

National Fuel Gas Distribution Corporation
Pennsylvania Division
OTS Uncollectible Expense Adjustment
to the Twelve Months Ending January 31, 2007

Development of Uncollectible Expense Ratio
for the most recent 5 years

LIRA Included		2002	2003	2004	2005	2006	Average 2004-2006
		$	$	$	$	$	
a.	Net Write-off - 12 months ended January 31, 2002 through 2006	3,403,202	6,612,838	3,907,131	5,645,305	6,866,444	16,418,880
b.	Divided by Gross Revenue - 12 months ended January 31, 2002 through 20(	264,255,438	288,142,594	257,145,399	306,162,445	322,800,403	886,108,247
c.	Calculated net write-off factor	0.012878456	0.02294988	0.015194248	0.018438921	0.021271485	0.018529203
d.	Gross revenue for the twelve months ending January 31, 2007	424,136,066	424,136,066	424,136,066	424,136,066	424,136,066	
e.	d * c = projected uncollectible accounts expense for the 12 mos. ending January 31, 2002 through 2006	5,462,218	9,733,872	6,444,429	7,820,611	9,022,004	

National Fuel Gas Distribution Corporation
Pennsylvania Division
OTS Uncollectible Expense Adjustment
to the Twelve Months Ending January 31, 2007

Development of Uncollectible Expense Ratio
for the most recent 5 years

Month/Yr	Gross Revenue $	Month/Yr	Write-offs Less Taxes $	Recoveries $	Note 1 Net Write-offs $	LIRA Write-offs	Net Write-offs
Feb-00	38,204,591	Feb-01	238,041	78,923	159,118		
Mar-00	25,779,427	Mar-01	336,335	84,428	251,907		
Apr-00	22,200,541	Apr-01	958,487	85,362	873,125		
May-00	15,255,188	May-01	624,663	87,899	536,784		
Jun-00	9,607,746	Jun-01	586,061	83,268	502,793		
Jul-00	7,404,915	Jul-01	331,667	112,811	218,856		
Aug-00	7,493,934	Aug-01	316,939	59,817	257,122		
Sep-00	8,637,379	Sep-01	192,693	76,128	116,565		
Oct-00	13,280,060	Oct-01	218,033	93,604	124,429		
Nov-00	19,587,006	Nov-01	190,310	69,306	121,004		
Dec-00	42,321,225	Dec-01	144,797	84,095	60,702		
Jan-01	54,483,428	Jan-02	276,384	95,587	180,797		
	264,255,438		4,394,430	991,228	3,403,202	0	0
Feb-01	47,159,427	Feb-02	458,175	92,331	365,844		
Mar-01	50,454,742	Mar-02	487,570	103,249	384,321		
Apr-01	39,423,515	Apr-02	1,442,926	91,070	1,351,856		
May-01	20,165,775	May-02	1,380,087	89,690	1,290,397		
Jun-01	14,825,622	Jun-02	994,107	63,921	930,186		
Jul-01	9,893,413	Jul-02	759,548	115,296	644,252		
Aug-01	8,595,900	Aug-02	619,101	71,823	547,278		
Sep-01	8,036,497	Sep-02	424,197	79,922	344,275		
Oct-01	12,033,587	Oct-02	431,592	116,630	314,962		
Nov-01	17,735,420	Nov-02	312,594	82,770	229,824		
Dec-01	22,441,088	Dec-02	221,316	95,871	125,445		
Jan-02	35,777,610	Jan-03	214,737	130,539	84,198		
	288,142,504		7,745,950	1,133,112	6,612,838	0	0
Feb-02	31,253,154	Feb-03	270,072	137,875	132,197	27,111	105,086
Mar-02	30,573,040	Mar-03	283,340	99,941	183,399	22,029	161,370
Apr-02	25,881,264	Apr-03	1,227,157	116,809	1,110,348	20,203	1,090,145
May-02	17,873,971	May-03	686,807	84,178	602,629	17,894	584,735
Jun-02	11,871,911	Jun-03	512,374	57,399	454,975	29,817	425,158
Jul-02	7,493,977	Jul-03	425,112	61,512	363,600	29,475	334,125
Aug-02	7,451,504	Aug-03	333,926	74,459	259,467	31,230	228,237
Sep-02	8,716,195	Sep-03	279,504	72,383	207,121	30,624	176,497
Oct-02	11,347,800	Oct-03	258,272	103,604	154,668	33,348	121,320
Nov-02	22,278,381	Nov-03	266,934	60,159	206,775	26,411	180,364
Dec-02	37,651,282	Dec-03	201,524	95,142	106,382	21,016	85,366
Jan-03	44,852,920	Jan-04	230,296	104,726	125,570	18,614	106,956
	257,145,399		4,975,318	1,068,187	3,907,131	307,772	3,599,359
Feb-03	40,905,823	Feb-04	303,990	112,028	191,968	22,096	169,272
Mar-03	45,342,280	Mar-04	450,217	134,581	315,656	30,771	284,885
Apr-03	29,285,692	Apr-04	1,387,699	140,792	1,246,907	30,689	1,216,218
May-03	19,052,186	May-04	1,058,426	80,512	977,914	65,504	912,410
Jun-03	12,516,095	Jun-04	864,588	94,409	790,179	66,943	723,236
Jul-03	7,943,580	Jul-04	726,165	72,647	653,518	57,965	595,553
Aug-03	8,340,148	Aug-04	466,517	86,221	380,296	46,050	334,246
Sep-03	9,159,734	Sep-04	389,921	131,548	258,373	53,024	205,349
Oct-03	15,486,804	Oct-04	527,135	120,016	407,119	82,138	324,981
Nov-03	21,835,194	Nov-04	250,633	98,187	152,446	27,867	124,579
Dec-03	37,114,504	Dec-04	219,818	116,479	103,339	26,527	76,812
Jan-04	50,180,605	Jan-05	301,305	133,715	167,590	27,673	139,917
Total	306,162,445		6,968,420	1,323,115	5,645,305	537,847	5,107,458
Feb-04	56,370,825	Feb-05	369,644	137,537	232,107	27,080	205,027
Mar-04	43,212,342	Mar-05	806,250	90,792	515,458	34,776	480,682
Apr-04	34,765,582	Apr-05	1,931,388	102,200	1,829,188	55,953	1,773,235
May-04	19,250,258	May-05	1,367,039	113,231	1,253,808	76,934	1,176,874
Jun-04	11,101,438	Jun-05	1,092,246	91,631	1,000,615	103,679	896,936
Jul-04	9,356,538	Jul-05	791,078	92,617	698,459	83,280	615,179
Aug-04	9,021,156	Aug-05	582,095	125,308	456,787	52,263	404,524
Sep-04	9,352,859	Sep-05	470,865	133,450	346,406	66,780	279,626
Oct-04	14,284,826	Oct-05	350,824	159,785	191,039	55,963	135,076
Nov-04	23,018,627	Nov-05	321,377	154,191	167,186	49,225	117,961
Dec-04	40,074,667	Dec-05	284,648	236,404	48,444	29,966	18,478
Jan-05	52,991,285	Jan-06	327,070	200,723	126,947	28,780	98,167
Total	322,800,403		8,504,322	1,837,870	6,666,444	864,679	6,201,765

Note 1: Net Write-offs = Write-offs less taxes - Recoveries

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OTS-RE-2
Witness: Frank
Page 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OTS INTERROGATORIES

2. Reference Exhibit No. 104, Schedule 102 (Uncollectibles).
A. Provide the net write-offs for the twelve months ended 1/31/04
B. Provide the gross revenues for the twelve months ended January 31, 2003

Response:

A & B

The following schedule details net write-offs for twelve months ended January 31, 2004 and gross revenues for twelve months ended January 31, 2003.

Month/Yr	Gross Revenue
Feb-02	$ 31,253,154
Mar-02	$ 30,573,040
Apr-02	$ 25,881,264
May-02	$ 17,673,971
Jun-02	$ 11,971,911
Jul-02	$ 7,493,977
Aug-02	$ 7,451,504
Sep-02	$ 8,716,195
Oct-02	$ 11,347,800
Nov-02	$ 22,278,381
Dec-02	$ 37,651,282
Jan-03	$ 44,852,920
Total	$ 257,145,399

Month/Yr	Gross Write-Offs Less Sales Tax	Recoveries	Net Write-Offs *
Feb-03	$ 270,072	$ 137,875	$ 132,197
Mar-03	$ 283,340	$ 99,941	$ 183,399
Apr-03	$ 1,227,157	$ 116,809	$ 1,110,348
May-03	$ 686,807	$ 84,178	$ 602,629
Jun-03	$ 512,374	$ 57,399	$ 454,975
Jul-03	$ 425,112	$ 61,512	$ 363,600
Aug-03	$ 333,926	$ 74,459	$ 259,467
Sep-03	$ 279,504	$ 72,383	$ 207,121
Oct-03	$ 258,272	$ 103,604	$ 154,668
Nov-03	$ 266,934	$ 60,159	$ 206,775
Dec-03	$ 201,524	$ 95,142	$ 106,382
Jan-04	$ 230,296	$ 104,726	$ 125,570
Total	$ 4,975,318	$ 1,068,187	$ 3,907,131

* Net write-offs = Gross write-offs less sales tax - Recoveries

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OTS-RE-3
Witness: Frank
Page 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OTS INTERROGATORIES

3. Provide the following information for uncollectible accounts expense.
A. The amount of gross write-offs for the twelve months ended 1/31/04, 1/31/05 and 1/31/06
B. Indicate that portion of the gross write-offs reported in part A for each year that represents LIRA average forgiveness.
C. Indicate that portion of gross write-offs reported in Part A for each year that represents LIRA cap credits.

Response:

A.
The following schedule details the gross write-offs less sales tax for the twelve months ended 1/31/04, 1/31/05 and 1/31/06. Gross write-offs less sales tax for twelve months ended 1/31/05 & 1/31/06 were included on Exhibit 104, Schedule 2 (Uncollectibles), page 7 and have been repeated below.

Month/Yr	Gross Write-Offs Less Sales Tax
Feb-03	$ 270,072
Mar-03	$ 283,340
Apr-03	$ 1,227,157
May-03	$ 686,807
Jun-03	$ 512,374
Jul-03	$ 425,112
Aug-03	$ 333,926
Sep-03	$ 279,504
Oct-03	$ 258,272
Nov-03	$ 266,934
Dec-03	$ 201,524
Jan-04	$ 230,296
Total	$ 4,975,318

Month/Yr	Gross Write-Offs Less Sales Tax
Feb-04	$ 303,996
Mar-04	$ 450,217
Apr-04	$ 1,387,699
May-04	$ 1,058,426
Jun-04	$ 884,588
Jul-04	$ 726,165
Aug-04	$ 468,517
Sep-04	$ 389,921
Oct-04	$ 527,135
Nov-04	$ 250,633
Dec-04	$ 219,818
Jan-05	$ 301,305
Total	$ 6,968,420

Month/Yr	Gross Write-Offs Less Sales Tax
Feb-05	$ 369,644
Mar-05	$ 606,250
Apr-05	$ 1,931,388
May-05	$ 1,367,039
Jun-05	$ 1,092,246
Jul-05	$ 791,076
Aug-05	$ 582,095
Sep-05	$ 479,865
Oct-05	$ 350,824
Nov-05	$ 321,377
Dec-05	$ 284,848
Jan-06	$ 327,670
Total	$ 8,504,322

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Witness: Frank
Page 2

B.
The following schedule details the LIRA average forgiveness for the twelve months ended 1/31/04, 1/31/05 and 1/31/06. LIRA average forgiveness is a subset of gross write-offs less sales tax, which is referenced on page 1 of this response.

Month/Yr	LIRA Forgiveness Written-Off *
Feb-03	$ 27,111
Mar-03	$ 22,029
Apr-03	$ 20,203
May-03	$ 17,894
Jun-03	$ 29,817
Jul-03	$ 29,475
Aug-03	$ 31,230
Sep-03	$ 30,624
Oct-03	$ 33,348
Nov-03	$ 26,411
Dec-03	$ 21,016
Jan-04	$ 18,614
Total	$ 307,772

Month/Yr	LIRA Forgiveness Written-Off *
Feb-04	$ 22,696
Mar-04	$ 30,771
Apr-04	$ 30,689
May-04	$ 65,504
Jun-04	$ 66,943
Jul-04	$ 57,965
Aug-04	$ 46,050
Sep-04	$ 53,024
Oct-04	$ 82,138
Nov-04	$ 27,867
Dec-04	$ 26,527
Jan-05	$ 27,673
Total	$ 537,847

Month/Yr	LIRA Forgiveness Written-Off *
Feb-05	$ 27,080
Mar-05	$ 34,776
Apr-05	$ 55,953
May-05	$ 76,934
Jun-05	$ 103,679
Jul-05	$ 83,280
Aug-05	$ 52,263
Sep-05	$ 66,780
Oct-05	$ 55,963
Nov-05	$ 49,225
Dec-05	$ 29,966
Jan-06	$ 28,780
Total	$ 664,679

* Excludes sales tax

C.
At National Fuel Gas Distribution Corporation's Pennsylvania Division, LIRA cap credits do not impact gross write-offs.

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OTS-RE-52
Witness: Friedrich-Alf
Page 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OTS RE INTERROGATORIES

52. Provide the amount of co-op advertising claimed in the future test year.

Response

The amount of co-op advertising included in the company's claim is $150,000.

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OCA 5-1
Witness: Friedrich-Alf
Page 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OCA SET 5 INTERROGATORIES

1. Please provide an update of the information contained in the schedule accompanying the Annual Report on the Delta Fund report submitted on December 30, 2005 identifying expenditures, revenues and a description of expenditures for the year ended September 30, 2006 to date.

Response

The attached pages are representative of the report that will be filed in December 2006 using information through June 30, 2006.

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OCA 5-1
Witness: Friedrich-Alf
Page 2

National Fuel Gas Distribution Corporation
Pennsylvania Division

Annual Filing of Delta Fund Revenues and Expenditures
For the period ended September 30, 2006 AS OF JUNE 30, 2006

	Annual		Cumulative		
Year Ended	Expenditures	Revenues	Expenditures	Revenues	Balance
Sept..2005	$92,300	$113,927	$92,300	$113,927	($21,627)
Sept. 2006	$376,800	$452,392	$469,100	$585,851	($116,751)
Sept. 2007					
Sept. 2008					
Sept. 2009					

Note 1: Rates were effective April 15, 2005 therefore the report ended September 30, 2005 does not represent a 12 month period of revenue collection.
Note 2: The September 2006 numbers are through June 30, 2006 in response to this interrogatory

Description of Actual Expenditures - Period ended September 2006 thru June 30, 2006

$192,300 was submitted to Utilization Technology Development, NFP (UTD) for the April 1, 2006 through March 31, 2007 dues.

$184,500 was submitted to Operations Technology Development, Co. (OTD) for the 2006 membership fee.

Specific projects UTD applied National Fuel's funds to were:

1.	Demonstration of a Human-Machine Interface (HMI) Control/Diagnostic System for Stationary Engines	$19,133
2.	Gas Technology Advisor for Commercial Applications – Space Heating Module	$39,230
3.	Recuperative Reformer for High Efficiency and Ultra-low emission for Distributive Generation with Reciprocating Engines (Phase II)	$14,580
4.	Zero emission Power from waste heat (ZEPH process)	$7,384
5.	Field Demonstration of Superboiler Prototype	$4,024
6.	Deployment of the Reverse Annulus Single Ended Radiant Tube (RASERT)	$7,384
7.	Commercial Pressure Fryer Beta Testing	$2,031
8.	Direct Flame Impingement Technology for the Non-ferrous Industry	$7,384
9.	Energy & Water Recovery from Flue Gases in Retrofit Applications	$30,539
10.	Optimization of a Gas-fired Glow Tube for Process Heating	$48,291
	Unallocated Amount	$5,719
	Net Administration Fee	$6,601
Total		$192,300

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Witness: Friedrich-Alf
Page 3

Specific projects OTD applied National Fuel's funds to were:

1.	Miniature Ethane/Methane Detector (EMD) for Leak Survey	$9,446
2.	Hand-held Acoustic Pipe Detector	$4,143
3.	Commercialization of an Obstacle Detection System Using GPR	$13,809
4.	Portable Methane Detector (PMD) Improvements & Field Evaluations	$4,100
5.	Commercial-Grade Acoustic Pipe Locator	$12,082
6.	Micro Excavation Commercialization and Application Development	$5,178
7.	High Pressure Plastic Pipe Materials	$2,456
8.	Increase in Design Factor – Phase I & II	$2,764
9.	50 – 70 Year Maintenance-Free Pipeline Coatings for Critical Locations	$6,723
10.	Ultrasonic Inspection of Fusion Welds on PE Mains	$5,178
11.	"Black Powder" Contamination in the Gas Industry: Survey & Best Practice Manual	$6,905
12.	Development/Enhancement of Trenchless Service Installation Through Keyholes	$5,182
13.	Reduce Mandated Inspection Costs by Remote Field Eddy Current Inspection of Unpiggable Pipelines	$5,745
14.	Inspection Platforms for Unpiggable Pipelines (NY Gas)	($3,038)
15.	Broadband Electromagnetic Technology – Sensor to Measure Wall Thickness	$7,661
16.	Camera Inspections on Live Mains thru Keyholes	$9,014
17.	Monitor Internal Corrosion Using Fluidized Sensors	$11,506
18.	Methods Development of Perimeter Air Monitoring During MGP Site Cleanups	$5,178
19.	2006 SMP	$34,523
20.	Keyhole Project	$6,905
21.	Developing and Demonstrating Rapid Quantitative PCB Analysis in the Field	$18,345
	Net Administration Fee	$8,631
	Allocation of Funds from Prior Years	($9,823)
	Unallocated Funds for Current Year	$11,887
Total		$184,500

Projected Expenditures - Period Ending September 2007

1. Utilization Technology Development (UTD) dues of approximately $92,000. Specific projects to be determined.

2. Operations Technology Development (OTD) dues of approximately $184,000. Specific projects to be determined.

3. Field support for local demonstration of UTD projects of approximately $100,000 – 115,000.

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OTS-RE-22
Witness: Friedrich-Alf
Page 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OTS RE INTERROGATORIES

22. Reference Exhibit No. 104, Schedule 2 (Pipeline Integrity) p. 35. Provide the following information regarding the Distribution Component.

A. If a final rule for Integrity Management of Gas Distribution will not be issued until the end of 2006, when does NFG expect to incur the $1,040,497 in expenditures?

B. Will this be an annual recurring expense?

C. Provide the amount of expenses incurred to date.

D. Does the Company plan to implement the program before a final ruling?

E. What is the nature of the Operations Supervision expense of $52,923? Whose employees will be providing this supervision?

Response

A. The company expended $8,080,542 in fiscal 2005 on specific activities to achieve the high standards currently experienced. The incremental expense of $1,040,497 was based on these expenditures and represents the incremental amount needed to achieve even higher standards. Standard thresholds from the New York Division are already being instituted in Pennsylvania and costs are being incurred in the future test year.

B. Yes

C. See response to A.

D. The company is already in the process of instituting the standard thresholds established in the New York Division. Other areas of compliance will be addressed upon receipt of the final ruling.

E. The incremental $52,923 will be expensed in FERC Detail Account 870000 which is titled Operations Supervision and Engineering. The expense will be for compliance testing and training.

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OCA 5-6
Witness: Friedrich-Alf
Page 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OCA SET 5 INTERROGATORIES

6. With regard to the distribution component of the pipeline integrity project expenditures shown on Exhibit No. 104, Schedule 2, page 35:

a. Please provide a copy of the Phase I Report referenced at lines 4-5 on page 27 of Statement No. 102.

b. Please provide a copy of any written analyses prepared by Distribution with regard to that Phase I Report.

c. Please provide a copy of any draft of the final rule that is not expected until the end of 2006 as referenced at lines 20-21 on page 27 of Statement No. 102.

d. Please provide a copy of any draft or preliminary compliance plans that the Company has prepared to meet the requirements discussed on page 27 of Statement No. 102.

e. Please provide a copy of any studies or analyses which document the incremental compliance costs (O&M and capital) reflected on Schedule 2, page 35.

Response

a. Due to the volume of this report, a copy has been sent to the OCA consultant only. Others can view it at: http://www.cycla.com/opslswc/docs/S8/P0068/DIMP_Phase1Report_Final.pdf

b. The company has not prepared any written analysis in response to the Phase I report. The company is participating in the Northeast Gas Association (NGA) Distribution Pipeline Integrity Committee. The company anticipates that the committee will respond, through NGA, to any proposed regulations or industry standards. The company also anticipates that NGA will develop a framework for compliance with the new regulations for member companies to use and customize.

c. The company is not aware of any draft final copies.

d. The company is in the process of reviewing the December 2005 report but will not prepare any formal compliance plans until after the final rule is issued.

e. Please see response to OCA 3-51.

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OCA 3-51
Witness: Friedrich-Alf
Page 3

Pennsylvania Division
Projected Annual Increase in Expenditures
Resulting From Proposed Distribution Integrity Management Regulations

Operations O&M Activities	Current Annual Expenditures (Incl. Benefits) FY 2005	Projected Increase %	Projected Increase $
Operation of Mains and Services			
Activity Description			
540520 Inspect/Lube Valve	$123,336	5%	$6,167
540540 Stake/Locate for 3rd Party Construction	$1,754,377	20%	$350,875
540570 Leak Survey - Service	$230,230	10%	$23,023
540580 Leak Survey - Main	$217,923	10%	$21,792
540590 Leak Survey - Business District	$82,429	10%	$8,243
540600 Exposed Piping Survey	$10,712	10%	$1,071
540620 Reinvestigate Leak	$196,652	5%	$9,833
Maintenance of Mains			
Activity Description			
640300 Leak Repair - Plastic	$75,166	0%	$0
640310 Leak Repair - Steel	$1,379,886	10%	$137,989
640320 Leak Repair - Cast Iron	$1,566	10%	$157
640330 Leak Investigation by Crew - No Leak Found	$91,199	10%	$9,120
640340 Third Party Damage	$301,461	-10%	($30,146)
Maintenance of Services			
Activity Description			
642090 Third Party Damage	$173,902	-10%	($17,390)
Operation of Transmission Mains			
Activity Description			
530710 Inspect/Lube Valve	$5,090	5%	$255
530840 Patrolling	$16,468	10%	$1,647
Maintenance of Mains			
Activity Description			
630660 Leak Repair	$973	10%	$97
Training and Meetings			
Activity Description			
540002 Distribution Compliance Testing/Training	$264,615	20%	$52,923
544070 Plastic Pipe Training	$47,431	20%	$9,486
Miscellaneous			
Activity Description			
544000 Distribution Office Expense	$3,107,124	5%	$155,356
Public Education			
Written/TV/Radio/Bill Inserts/Policy Manual	$0		$300,000
Total Projected Increase to Operations and Maintenance Expense			$1,040,497

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OTS-RE-24
Witness: Friedrich-Alf
Page 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OTS RE INTERROGATORIES

24. Reference Statement No. 102, p. 30.

A. Approximately when does NFG expect Supply's compliance filing will be made?

B. Under the Company's crediting proposal, would capacity release revenue and off-system sales still be subject to review in the Company's annual PGC filing?

Response

A. Supply Corporation filed its compliance plan, pre-existing waiver justification, third party supplemental petition and motion for clarification with the FERC on February 3, 2005 at Docket No. TS04-248 in response to the FERC September 20, 2004 Order. Distribution filed comments in support of Supply's filing on February 22, 2005. FERC has not issued an Order on this yet.

B. Capacity Releases and Off-System Sales would be subject to the 1307(f) annual filing and any reconciliation regarding the off-system sales or capacity release revenues would be accounted for in the deferral mechanism.

Prepared ByThe Office of Trial Staff
National Fuel Gas Distribution Corporation
Pennsylvania Division
CWC Lag for Pension Funding
Twelve Months Ended January 2006

OTS Exhibit No. 2
Schedule 7
Page 1 of 14

Payment Date	Payment Amount	MidPoint of Plan Year	Lag Days	Weighted Total
2/24/2005	$5,162,500	12/29/2004	57	$294,262,500
3/21/2005	763,062	12/29/2004	82	$62,571,084
Total	$5,925,562			$356,833,584
Pension Lag				60.22

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OTS-RE-165
Witness: Bauer
Page 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OTS RE INTERROGATORIES

165. Please separately provide the actual amounts and dates on which the Pension and OPEB plans were funded for the period 2/1/2005 through 1/31/2006. In your response, include a narrative explaining the Company's policy for funding the Pension and OPEB plans and provide the dates of the plan year for each fund.

Response

The amounts and dates of pension and OPEB funding are as follows:

				Plan Year
Pension				
February 24, 2005		$	5,162,500	June 30, 2004
March 21, 2005			763,062	June 30, 2004
OPEB				
February 24, 2005	401(h)	$	1,141,845	Sept 30, 2005
March 21, 2005	VEBA		3,067,452	Sept 30, 2005
June 30, 2005	VEBA		2,112,273	Sept 30, 2005
September 22, 2005	VEBA		953,177	Sept 30, 2006
December 5, 2005	VEBA		2,172,523	Sept 30, 2006
January 30, 2006	VEBA		3,127,063	Sept 30, 2006

Funding Policy:
The Company's policy is to fund the pension plan with an amount necessary to satisfy the minimum funding requirements of applicable laws and regulations and not more than the maximum amount deductible for federal income tax purposes. In determining the amount to fund, the Company considers, among other things, the funded status of the plan, the current and expected return on the plan's investments, the level of cash expected to flow out of the plan in the form of retiree benefits, and estimates of future minimum funding requirements. If, when reviewing those factors, a significant increase or spike in future minimum funding requirements is projected, management would attempt to levelize annual contributions in order avoid those significant funding increases or spikes.

In accordance with the Pennsylvania Public Utility Commission's policy statement on OPEBs, the Company funds the full amount of its OPEB rate recovery to the external trusts.

R-00061493
OTS-RE-59
Witness: Truitt
Page 1 of 3

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OTS RE INTERROGATORIES

Q. Reference NFG-2-37, Exhibit No. 8-D, page 11 of 72, Goods and Services.

A. Please identify what the last 3 column headings of (I + R)/2, AD-R and AE * U stand for.

B. Please explain the nature of the Inter Co Billings throughout the Goods and Services workpapers (i.e. payment dates 2/25/05 with the amounts of $35,855.24 and $308,441.71) and why they are lagged at one day.

C. What are the terms under the affiliated interest agreement with the Parent Company?

D. What does CP006976666 in the description column refer to?

E. Please explain the nature of the Caremark Claims 2/5-18 with a date of 2/23/05 in the amount of $27,006.86.

F. Please explain why the Caremark Claims are included on the Goods and Services workpapers, and would not have already been included in the lag calculation for Prescription Drugs.

G. Explain the Computer Purchase dated 2/2/05 from Melanie S. Cadden for $1,624.43 and why a 1 lag day was calculated.

H. Please explain the Employee Other Expense on 2/7/05 for $6,370.12 and how the 1.50 lag day was calculated.

I. Reference the Employee Computer Purchase on 2/14/05 of $1,409 and how the 1.5 lag day was calculated.

J. Reference the four Interest Reductions dated 2/23/05 and explain the nature of these claims and how the lag days were calculated.

A. Each part of this interrogatory and following interrogatories asks the general question "How was the lag days calculated?" All of the lag days were calculated in the same manner. The midpoint between the invoice date and the day invoice was recognized in accounting was calculated. Then the days between that midpoint and the day the check was issued was calculated. This is the days lag.

The rationale behind this method is as follows. Items in the lead lag study were identified through past practice and Commission decision for specific lead lag calculation. These items would be things like pension costs, labor costs, benefits, etc. For each item the service period was determined and the payment was then compared to the service period for the calculation of the days lead or lag. Not all items were studied individually. The items that were included in Goods and Services were the items not studied individually. In order to determine a reasonable claim for

cash working capital for the Goods and Services, a study of the accounts payable process was performed. This is what is included in NFG 2-37, page 11-72.

The study on Goods and Services shows that an average of 10.58 days lag occurs for the difference between the midpoint of the invoice date and the accounting date and the day the check is issued. This means that the company is only claiming a requirement for Goods & Services during the period between the invoice date and the day the check is issued. If each of these items were studied individually, a different claim would have been calculated.

A. The last three column headings refer to the alphabetical Excel spreadsheet column headings. The columns calculate the Midpoint Date, Lag Days and Weighted Average Amount, respectively. For example, the midpoint would be calculated by adding column I (titled Acctg Date) with Column R (titled Date) and dividing the total by 2.

B. The payments referencing Inter Co Billings relate to the payment of intercompany payable balances, which are paid in full on a monthly basis. The intercompany transactions flow through the general ledger system automatically based on the nature of the transaction and the business unit charged. Please refer to Exhibit No. 4, Schedule 11 for the Service Agreement.

C. Please refer to the Service Agreement located in Exhibit No. 4, Schedule 11.

D. The CP006976666 in the description column is the Company's DUNS Number (a number issued by Dun & Bradstreet) that identifies unique business locations).

E. Refer to response to OTS-RE-59 F below.

F. Product 2105 Other Employee Welfare Costs, as identified on NFG-2-37 page 4 of 72, is listed as CWC component Goods/Services. However, the Caremark PCS claims, which are summarized separately under the PCS Prescription Drug Plan, are also recorded on this product and should have been adjusted out of the query used as the basis for the Goods and Services data.

G. The Company offers a long-term loan program to assist employees with personal computer purchases. This purchase represents the loan to an employee under this benefit option.

H. The $6,370.12, on 2/7/05 represents vehicle expense paid through a working fund at a service center. This line item is the reimbursement of the working fund component.

I. The Company offers a long-term loan program to assist employees with personal computer purchases. This purchase represents the loan to an employee under this benefit option.

J. The interest reduction payments dated 2/23/05 represent interest buy-down payments on approved loans associated with area development.

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OTS-RE-64
Witness: Truitt
Page 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OTS RE INTERROGATORIES

Q. Reference NFG-2-37, Exhibit No. 8-D, page 17 of 72, Goods and Services.

A. Please explain the nature of the 2005 Audit Fees and Expenses to Pricewaterhouse Coopers LLP dated 3/28/05 in the amount of $11,881.80 and explain how the lag days of 5 was determined. How long did it take to complete the audit?

B. Explain the nature of the Monthly Lease Payment to Banc of America dated 3/1/05 in the amount of $7,931.44 and explain how the 5.50 lag days were determined.

C. Reference the Liheap and Crisis credits refunds to the PA Department of Public Welfare on 3/21/05 and 3/7/05 and explain how the lag days of 5 and 5.50 respectively were calculated.

D. Please explain the nature of the Expense Distribution to D L Peterson Trust dated 3/8/05 in the amount of $145,874.44 and explain how the 6 lag days were determined.

E. Please explain the nature of the Annual Subscription to Cooking for Profit magazine dated 3/28/05 and explain how the lag days of 6.50 was calculated.

A. For the answer to the questions on how the lags are calculated please see the response to OTS-RE-59.

A. This payment was a progress bill related to the professional accounting services rendered for the fiscal year ending September 30, 2005

B. Refer to response to OTS-RE-60 C.

C. Refer to response OTS-RE-59.

D. Refer to response to OTS-RE-60 A.

E. This payment covers the promotional expense for an annual magazine and food service gas equipment catalog subscription, which is mailed to various customers monthly.

	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	**Total**
Payroll						25							25
Unemployment						2							2
Benefits	7	10	10	9	9	10	8	8	7	11	8	7	104
Co-op Advertising	5	3	2	2	4		6	4	1				27
OPEB's/ VERBA		2			2		2	2			2		10
Vehicles				3	6	1	3	1	1			1	16
Loans for Computers	2	1			1		1	1					6
Dues/ Pledges	1					1							2
Subscriptions		1											1
Sponsorship/ Donation			4			1			1	1		1	8
Company Function													0
Country Club											1		1
Tuition													0
Stopped Payments	2				1						1	3	7
Voids		1	1				2		1		1	1	7
Leads													0
Taxes						29							29
													0
Duplicates													0
Tower	1												1
Kane Liquid	1												1
Geneva Pipeline	5												5
Galati Excavating	1												1
Control Mirco Systems		1											1
Venago Supply		1											1
IMR Limited Corporation		2									1		3
Kingtool			1					1		1			3
PennLine Serv.							1						1
Kayden								3	2	1	3	1	10
RL Rick Heating								1					1
US Bank								1					1
Warren Forrest								2					2
US IS Com								1					1
McLaughlin								2					2
Verizon								1					1
Hawley Landscape								1					1
Mainline											1		1
Fin Rec									1			1	2
Park Excavating									1				1
DL Peterson Trust											5		5
South-worth									1				1
Mercer Co.										2			2
Energy Assoc.												1	1
CBCS											1		1
Moore												1	1
LEADs			3					4					7
Below line comp. function					1				5	1		2	9
Total	25	22	21	14	24	69	23	33	21	17	24	19	312

Prepared by Office of Trial Staff
NFGD – Errors Goods and Services Lead Lag Study
R-00061493

Benefits - are summarized separately under the PCS Prescription Drug Plan and should have been adjusted out of the query used as the basis for the Goods and Services data.
P & A Administrative Services Inc. - Flexible Benefit Account - 25 different entries
CNA - Prem. Team GB - 11 different entries
Coresource - Admin. Fees and Dental Claims - 36 different entries
Pharmaceutical Card System Inc. - 25 different entries some with lag calculations
Caremark Claims - 3 different entries

OPEB

Northern Trust Company - Fund PAD Verbas - 6 entries
Northern Trust Company - Reim Verba Presc. Drug - 8 entries

Payroll Deposits

National Fuel Gas Federal Credit Union 12 entries dated 7/6 - 7/29/05
National Fuel Gas Dist Payroll 13 entries dated 7/1 -7/29/05
SEIU Firemen & Oilers Conf. dated 7/13/05 w/ a 1 lag day calc., NFG admits in payroll

Taxes

Commonwealth of PA dated 7/1/05
Internal Revenue Service 9 entries dated 7/1 - 7/25/05
PA Dept. of Revenue dated 7/15/05
Commonwealth of PA 3 entries dated 7/20/05 with a .50 lag day calculation
Internal Revenue Service 3 entries dated 7/28/05 with .50 lag day calculation
Internal Revenue Service 3 entries dated 7/11/05 the a 1.5 lag day calculation
Internal Revenue Service dated 7/5/005 with a 2 lag day calculation
City of Meadville Wage Tax Office dated 7/8/05 with a 4.5 lag day calculation
Receiver of taxes dated 7/8/05 with a 4.5 lag day calculation
Federal Reserve Bank of NY dated 7/8/05 with a 4.5 lag day calculation
Earned Income Tax office dated 7/8/05 with a 4.5 lag day calculation
St. Mary's Tax Service dated 7/8/05 with a 4.5 lag day calculation
Berkheimer Associates dated 7/8/05 with a 4.5 lag day calculation
Central Tax Bureau of PA dated 7/8/05 with a 4.5 lag day calculation
Receiver of Taxes dated 7/13/05 with a 7 lag day calculation

Unemployment Compensation

PA Unemployment Compensation, 2 entries dated 7/28/05 with a 1.5 lag day calculation

Prepared by Office of Trial Staff
NFGD – Errors Goods and Services Lead Lag Study
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Co-op Advertising - should not even be included in the Goods & Services lag calculations

Moore Heating & Cooling, dated 2/4/05 for $1,200.00 with a 5 lag day calculation
Wright Heating & Cooling, dated 2/4/05 for $1,519.80 with a 5 lag day calculation
Jordan Heating & A/C, dated 2/4/05 for $2,190.00 with a 5 lag day calculation
H Jack Langer Plumbing & Heating, dated 2/4/05 for $2,468.18 w/ a 5 lag day calc.
Greenville Comfort System, dated 2/11/05 for $1,620 with an 8 lag day calculation
Maleno Builders, dated 3/2/05 for $1,063.80 with a 3 lag day calculation
Moore Heating & Cooling, dated 3/2/05 for $1,200.00 with a 3 lag day calculation
Laughlin Builders, dated 3/2/05 for $1,500.00 with a 3 lag day calculation
Moore Heating & Cooling, dated 4/20/05 for $1,200.00 with a 4 lag day calculation
Robertson Kitchens, dated 4/20/05 for $1,293.60 with a 4 lag day calculation
Robertson Meadville, dated 5/9/05 for $1,010.38 with a 3 lag day calculation
Robertson Kitchen, dated 5/9/05 for $1,272.00 with a 3 lag day calculation
Nerthlings Heating & A/C, dated 6/15/05 for $1,359.00 with a 4.5 lag day calculation
Wright Heating & Cooling, dated 6/15/05 for $2,160.00 with a 4.5 lag day calculation
Pinnacle Plumbing, dated 6/15/05 for $2,190.00 with a 4.5 lag day calculation
M A Sprickman, dated 6/15/05 for $1,200.00 with a 6 lag day calculation
Standard Air & Light, dated 8/25/05 for $3,327.00 with a 3 lag day calculation
Fullerton Appliances, dated 8/9/05 for $2,419.56 with a 3.5 lag day calculation
Greenville Comfort System, dated 8/9/05 for $2,564.40 with a 3.5 lag day calculation
M A Sprickman, dated 8/30/05 for $1,200.00 with a 3.5 lag day calculation
Wright Heating & Cooling, dated 8/30/05 for $2,160.00 with a 3.5 lag day calculation
Deniziak Siding, dated 8/9/05 for $4,022.70 with a 10 lag day calculation
Duggans Service & Appl, dated 9/29/05 for $1,566.00 & $1,623.19 w/ a 1 lag day calc.
Duchini Ace Hardware, dated 9/29/05 for $1,733.18 with a 1 lag day calculation
Reeves Plumbing, dated 9/19/05 for $1,476.00 with a 3 lag day calculation
Jordan Heating & A/C, dated 10/12/04 for $1,440 with a 14.5 lag day calculation

Loans to Employees for Computer Purchases – This is something stockholders should be paying for.

Melanie S. Cadden dated 2/2/05, for $1,624.43 with a 1 lag day calculation
Foundation for Free Enterprise dated 2/14/05, for $1409 with a 2 lag day calculation
David A. Waples dated 3/30/05, for $2,064.84 with a 3 lag day calculation
Carl M Carlotti dated 6/27/05, for $1,169.97 with a 2 lag day calculation
Michelle M Kosko dated 8/25/05, for $1,162.79 with a 3 lag day calculation
Scott Swartzfager dated 9/29/05, for $1,449 with a 1.5 lag day calculation

Prepared by Office of Trial Staff
NFGD – Errors Goods and Services Lead Lag Study
R-00061493

Payments claimed, but checks stopped or voided

S- The Vanguard Group dated 2/9/05, 2 line entries with a 6.5 lag day calculation.
V- Penn. Oil & Gas Association dated 3/15/05 with a 2 lag day calculation
V- JPMorgan Chase Bank dated 4/4/05 Renewal of Registration with a 9.5 lag day calc.
S- Northwest PA MAE Corp. dated 6/29/05 with a 14.5 lag day calculation
V- Pa PUC dated 8/30/05 with a 3 lag day calculation
V- McLaughlin Construction dated 8/30/05 with a 7 lag day calculation
V- Commonwealth of Pennsylvania dated 10/17/05 with a 5 lag day calculation
S- Moore Heating & Cooling, 2 entries dated 12/2/05 for $1,750.20 w/ a 5 lag day calc.
V- Northwest PA Mae Corp. dated 12/21/05 for $1,350 w/ a 14.5 lag day calculation
S- Collins Plumbing & Heating dated 1/30/06 for $2,188.16 w/ a 6.5 lag day calc.
S- Collins Plumbing & Heating dated 1/30/06 for $4,184.18 w/ a 7 lag day calculation
S- Collins Plumbing & Heating dated 1/30/06 for $3,188.77 w/ an 8.5 lag day calc.

Vehicle Purchases

DL Peterson Trust dated 5/20/05, $29,472.05 with a 5.5 lag day calculation
DL Peterson Trust dated 5/2/05, $16,997.06 with a 6 lag day calculation
DL Peterson Trust dated 5/9/05, $17,484.68 with a 6 lag day calculation
Boss Industries Inc 4 entries dated 6/22/05, $81,318.00 with a 13.5 lag day calculation
Southworth-Milton Inc. 2 entries dated 6/29/05, $30,824.19 with a 14.5 lag day calc.
Boss Industries Inc. dated 7/20/05, $88,026.74 with a 27.50 lag day calculation
DL Peterson Trust dated 8/23/05 in the amount of $169,113.33
DL Peterson Trust dated 8/29/05 in the amount of $19,246.16
Horizon Energy Development Inc. dated 8/30/05, $23,500 w/ a 4 lag day calc.(Transfer)
DL Peterson Trust dated 9/9/05 for $15,733.75
DL Peterson Trust dated 10/4/05 for $17,509.00
DL Peterson Trust dated 1/17/06 for $21,474.00

Leads

Shoreline Construction Co - 3 line entries dated 4/20/05 with a 526 lead calculation paid 3/7/08
Fessenden Construction Co. Inc. dated 9/13/05 with a lead of 6.5. Paid 13 days before invoice date.

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NFGD – Errors Goods and Services Lead Lag Study
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Identical Line Postings that appear to be duplications

Kane Liquid Fuels Inc. - 2 line entries dated 2/18/05 with an 11 lag day calculation
Geneva Pipeline LLC - 10 line entries dated 2/16/05 with a lag day calculation of 13.
Galati Excavating Inc. - 2 line entries dated 2/16/05 with a lag day calculation of 16.5
Bressler Communications - 2 line entries dated 2/2/05 to Install a new Oil City Radio Tower with a lag calculation of 19 and NFG admits this was a duplication, and they capitalized the tower
Venango Supply - 2 line entries dated 3/9/05 with a 6.5 lag day calculation
Control Microsystems Inc - 2 lines entries dated 3/23/05 with a 14 lag day calculation
IMR Limited Corp - 6 line entries dated 3/7/05 with a 170.50 lag day calculation
Bass Industrial Equip Inc - 3 line entries dated 4/20/05 with a 13 lag day calculation
Penn Line Serv. Inc. - dated 8/30/05 w/ a 15 lag day calc., duplicate payment. Refunded.
RL Rick Heating & A/C Inc. - 2 entries dated 9/21/05 with a 6.5 lag day calculation
US Bank - 2 entries dated 9/21/05 with a 13.5 lag day calculation
Kingtool Co. - 2 entries dated 9/8/05, 13.5 lag day calc., (changed terms to match PO)
Kaydyn Direction Drilling, Inc., 2 entries dated 9/29/05, 13.5 lag day calc. (Incorrect BU)
Kaydyn Direction Drilling, Inc.- 2 entries dated 9/23/05, 14 lag day calc (Incorrect BU)
Warren-Forest Counties Econ.- 2 entries dated 9/13/05, 14.5 lag day calc. (PO changed)
USIS Commercial Services Inc.- dated 9/29/05, 14.5 lag day (Acct. number changed)
McLaughlin Construction - 4 entries dated 9/8/05, 14.5 lag day (PO changed)
Warrem-Forest Counties Econ. - 2 entries dated 9/15/05, 15 lag day, (PO changed)
Kaydyn Directional Drilling, Inc. - 2 entries dated 9/29/05, 17 lag day (Incorrect BU)
Hawley Landscaping Inc. - 2 entries dated 9/8/05, 19 lag day (PO Changed)
Verizon - 2 entries dated 9/1/05 with a 23.5 lag day
Park Excavating & Welding - 3 entries dated 10/5/05 with a 4.5 lag day calculation
Financial Recoveries - 2 entries dated 10/17/05 with an 8.5 lag day calculation
Kaydyn Directional Drilling, Inc. - 2 entries dated 10/26/05, $6,075 w/ a 13 lag day calc.
Southworth-Milton Inc.- 2 entries dated 10/26/05 for $11,983.30 w/ a 14 lag day calc.
Kaydyn Direction Drilling, 2 entries dated 10/29/05, w/ a 20 lag day calc. (Incorrect PO)
Mercer Co. Com. Action, 2 entries dated 11/18/05 w/ a 5 lag day calc. (PO Change)
Kingtool Co., 3 entries dated 11/23/05, for $2,335 with a 13 lag day calc.
Kaydyn Direction Drilling, 2 entries dated 11/9/05 w/ a 13 lag day calc. (Incorrect BU)
Mercer Co. Com. Action, 2 entries dated 11/23/05 for $6,292.50 with a 14.5 lag day calc.
DL Peterson Trust, 2 entries dated 12/12/05 for $1,040.23 w/ a 1.5 lag day calc.
DL Peterson Trust, 2 entries dated 12/12/05 for $9,781.92 w/ a 1.5 lag day calc.
DL Peterson Trust, 2 entries dated 12/12/05 for $18,637.18 w/ a 1.5 lag day calc.
DL Peterson Trust, 2 entries dated 12/12/05 for $19,091.48 w/ a 1.5 lag day calc.
DL Peterson Trust, 2 entries dated 12/12/05 for $20,884.71 w/ a 1.5 lag day calc.
IMR Limited Corp., 2 entries dated 12/16/05 w/ a 12.5 lag day calc. (due date changed)
CBCS National 2 entries dated 12/28/05 for $3,345.66 with a 14 lag day calc.
Kaydyn Directional Drilling, 2 entries dated 12/28/05 w/ 16.5 lag day calc. (PO changed)
Kaydyn Directional Drilling, 2 entries dated 12/5/05 w/ a 19 lag day calc. (PO changed)
Mainline Info. Systems 2 entries dated 12/9/05 w/ 19.5 lag day calc. (Prod. Code change)
Kaydyn Directional Drilling, 2 entries dated 12/9/05 w/ a 24.5 lag day calc. (PO changed)

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Kaydyn Directional Drilling, 2 entries dated 1/11/06 w/ a 13 lag day calc. (Incorrect BU)
Financial Recoveries, 2 entries dated 1/30/06 w/ a 15 lag day calc. (price correction)
Energy Assoc. of PA, 3 entries dated 1/9/06 w/ a 19 lag day calc. (booked at full amt. and then booked in 2 parts for tax purposes)
Moore Heating & Cooling, 2 entries dated 1/6/06 for $1,750.20 w/ a 22.50 lag day calc.

Donations

Dr. Gertrude A Barber Center, dated 2/2/05 pledge for $5,000 w/ a 31.5 lag day calc.
Celebrate Erie sponsor, 2 entries dated 4/4/05 for $1,000 with a 7 lag day calculation
Presque Isle Sponsorship 2 entries dated 4/25/05 for $1,500 with a 9 lag day calculation
American Heart Association dated 7/8/05 for $1,000 with a 5 lag day calculation
United Way of Erie County dated 10/5/05 for $3,540. 12 with a 2.5 lag day calculation
Gannon University dated 10/12/05 for $1,200 for a table at an event, w/ a 6 lag day calc.
Boys & Girls Club of Erie, 1/18/06 for $1,100 silver patron sponsorship w/ a 3.5 lag day

Miscellaneous Items

Cooking for Profit magazine dated 3/28/05 for $2,518.36 with a 6.5 lag day calculation
Erie Otters dated 3/23/05 for $1250.00 with a 10 lag day calculation
Michael Colpoys, 6/24/05 emp. meal exp./Equip. Rental, $3,476.33 w/ 9 lag day calc.
Cross Creek Resort dated 10/3/05 dinner for $2,274.44 with a 3 lag day calculation
Sears Corp. Gift Card Sales dated 10/19/05, awards for $14,153.38 w/ a 3 lag day calc.
Lands End Bus. Outfitters, 10/14/05 for $1,337.79 logo items w/ an 18.5 lag day calc.
Six Flags Darien Lake dated 10/3/05 family picnic for $6,650.31 w/ a 32.5 lag day calc.
Cross Creek Resort dated 11/4/05 dinner for $5,100.83 with a 4.5 lag day calculation
Erie Otters dated 11/23/05 for $1,350 advertising sponsorship with a 3 lag day calculation
Country Club of Hershey PA dated 12/13/05 for $1,662 with a 3.5 lag day calculation
Marketplace Grill dated 1/18/06 for Xmas Lunch $1,522.40 with a 3 lag day calculation
Michelle M Kosko dated 1/9/06 for $2,000 tuition reimb. with a 66 lag day calculation

Prepared by Office of Trial Staff
NFGD - Comparable Goods and Services Lag Days
R-00061493

Company	Docket No.	Claimed Misc/ Other Lag
TWPhillips	R-00051178	36.97
PPL	R-00061398	57.91
PG Energy	R-00061365	21.56
Duquesne Light	R-00061346	34.86
Penelec	R-00061367	30.00
MetEd	R-00061366	30.00
Aqua '05	R-00051030	32.20
Aqua '03	R-00038805	32.20
Pa American	R-00038304	24.60
Equitable	R-00963858	53.91
	Average	**35.42**

NFG DISTRIBUTION CORPORATION
COMPUTATION OF CASH WORKING CAPITAL
PER OFFICE OF TRIAL STAFF
($000)

LINE NO.	COST CATEGORY	PRO FORMA EXPENSES (a)	LEAD/LAG DAYS	WEIGHTED AVERAGE
1	Operating expenses:			
2	Gas Purchases	$ 320,398	40.20	$ 12,880,000
3	Weekly Payroll			
4	Net	7,555	14.00	105,770
5	Fed Witholding	1,115	15.70	17,506
6	State Witholding	290	38.45	11,151
7	FICA	722	15.70	11,335
	Gross	9,682		145,762
8	Supervisory Payroll			
9	Net	3,921	6.82	26,741
10	Fed Witholding	549	6.75	3,706
11	State Witholding	152	27.88	4,238
12	FICA	375	6.76	2,535
13	Gross	4,997		37,220
14	Hospitalization	2,687	8.36	22,463
15	Dental	206	(4.36)	(898)
16	Life Insurance	66	29.46	1,944
17	Prescription Drug	717	11.50	8,246
18	OPEB	8,653	30.72	265,820
19	Pension	3,623	60.22 (b)	218,175
20	Goods & Services	33,412	30.00 (c)	1,002,360
21	Total O&M Expenses	384,441		14,581,092
22	Taxes Other Than Income:			
23	FUTA	15	76.00	1,140
24	SUTA	49	76.00	3,724
25	FICA	1,061	12.86	13,644
26	Captal Stock	722	53.49	38,620
27	Pa Property Tax	33	(113.61)	(3,749)
28	PURTA	90	(10.80) (d)	(972)
29	Other	4	33.27	133
30	Total Taxes - Other Than Income	1,974		52,540
31	Income Taxes:			
32	Federal	775	37.25	28,869
33	State	146	55.45	8,096
34	Total Expenses	387,336	37.88	14,670,597
35	Net CWC Requirement			
36	Average Days Lag in Revenue			72.45
37	Average Days Lag in Expenses			37.88
38	Net Lag Days			34.57
39	Ave Daily Operating Expenses			1061
40	CWC Requirement			$ 36,679

(a) Reference NFG Exhibit 108, Schedule 4, pages 5-6.
(b) Reference OTS Exhibit No. 2, Schedule 7, p. 1 of 14
(c) Reference OTS Statement No. 2, p. 45
(d) Reference OTS Statement No. 2, p. 48

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OTS-RE-101
Witness: Bauer
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NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OTS RE INTERROGATORIES

OTS-RE-101 Provide the following information with regards to the Prescription Drug & Medicare Improvement Act of 2003.

A. What impact will the Act have on National Fuel Gas Co. and NFG Distribution Corporation?

B. What level of tax credits are anticipated for 2006?

C. Has the New York Public Service Commission addressed this issue with regards to NFG?

Response

A. Assuming that National Fuel Gas Company's ("National") subsidiaries, including National Fuel Gas Distribution Corporation continue to provide prescription drug benefits to retirees that are at least actuarially equivalent to Medicare Part D, National's subsidiaries will receive, effective January 1, 2006, a federal subsidy equal to 28% of individual beneficiaries' annual prescription drug costs between $250 and $5,000.

B. National and its subsidiaries will not receive any tax credits under the Prescription Drug, Improvement and Modernization Act of 2003 (the "Act"). Rather, the subsidy under the Act will be received in the form of a direct cash payment that is exempt from federal income taxes. Mercer Human Resource Consulting projects that, for the twelve months ended December 31, 2006, National will receive approximately $1.0 million of subsidies under the Act. The Pennsylvania Division's share of that amount will approximate $0.16 million.

C. The settlement agreement approved by the State of New York Public Service Commission (the "NYPSC") in the New York Division's last rate case (04-G-1047) included the following language:

Medicare Prescription Drug Improvement Act of 2003.

The effects of the Medicare Prescription Drug Improvement Act of 2003 (the "Act") have been included in the actuarial costs calculated for OPEB expenses. The intention of the Signatory Parties is that the Company remain on the Commission's Pension and OPEB Policy Statement. The impact of the Act on deferred income tax calculations has not been established in this Joint Proposal. On February 2, 2005, the Commission instituted a proceeding in Case 04-M-1693 to investigate the impact of the Act on deferred income taxes. The Signatory Parties agree that this issue will be determined in that proceeding.

The proceeding in Case 04-M-1693 is ongoing. Copies of all documents issued by the NYPSC in that case are attached to this response.