STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

CASE 07-G-0141 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service.

BRIEF ON EXCEPTIONS

RUTH A. AMES
Law Intern
518-474-6522

JOHN L. FAVREAU
Assistant Counsel
518-474-1573

SAUL A. RIGBERG
Assistant Counsel
518-486-2652

Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Date: October 17, 2007
Albany, New York

TABLE OF CONTENTS

STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

CASE 07-G-0141 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service.

BRIEF ON EXCEPTIONS OF THE DEPARTMENT OF PUBLIC SERVICE STAFF

INTRODUCTION

On January 29, 2007, National Fuel Gas Distribution Corporation (Distribution or company) filed amendments to its gas tariff proposing a general increase in its rates and charges of approximately $52 Million, which included approximately $12 Million for an energy efficiency program. On June 7, 2007, Department of Public Service Staff (Staff) and several other parties submitted pre-filed testimony in response to Distribution's filing. Staff's testimony recommended a $19.3 Million delivery rate decrease, along with a $10.8 Million energy efficiency program that would be funded through a surcharge. The most contentious and driving issues in the proceeding are return on equity, distribution of proceeds from settlements with insurance carriers regarding site investigation and remediation (SIR) costs, pension expense, depreciation, and concerns regarding local production and safety. Distribution seeks a hefty rate increase at the same time that the economy in its service territory is doing poorly.

On September 28, 2007, Presiding Administrative Law Judge William Bouteiller (ALJ) issued his Recommended Decision (RD). The RD is notable for its criticism of Staff and the company for not settling the case. On page 65, while discussing the issue of customer service standards, the RD states: "It is unfortunate that, after ten years, the parties have chosen to leave aside the incentive regulation approach and have reverted to the fully-litigated ratemaking style that was predominantly used in the 1970s and on the wane in the 1980s." This broadside misses the mark. Staff did not whimsically "choose" not to settle. Rather, it was our professional conclusion that the terms offered by the company were not in the public interest. As the discussions at the Commission's sessions during which the National Grid-KeySpan merger and the Consolidated Edison gas case were considered, the Commission appears to no longer find acceptable "black box" settlements and seems to prefer a fully litigated record.

In this brief, Staff addresses issues to which it takes exception to the RD's reasoning or conclusion, including, but not limited to, the following: 1) allocation methodology for SIR insurance settlement proceeds; 2) royalty adjustment; 3) interest on the internal pension reserve; 4) proxy groups and the use of a 50/50 DCF/CAPM methodology to compute the return on equity; 5) rate design issues; 6) late payment charges; 7) unbundling; 8) local production and meter maintenance issues; and 9) consumer service issues.[1]

SUMMARY OF CASE

The RD (at 3-4) presents Distribution's "Rate Case Overview" but fails to mention, yet alone discuss, the background perspectives offered by Multiple Intervenors (MI), Consumer Protection Board (CPB), or Staff. What is striking as the pervasive white noise associated with this case is the degree to which the corporate structure encourages National Fuel Gas Company (National), the corporate parent, to seize benefits for its shareholders at the expense of Distribution's ratepayers. Indeed, in every case pertinent to this rate filing, the corporate parent made decisions that were in the best interests of its shareholders (and, consequently, its management, no doubt in the form of bonuses and promotions) and not in the best interests of Distribution's ratepayers.

As CPB observed on page six of its initial brief while discussing the SIR insurance proceeds allocation issue:

> The benefit of shifting cost responsibility from unregulated to regulated subsidiaries is the elephant in the corner of the room that cannot be ignored when a holding company makes decisions concerning cross-subsidiary cost and benefits allocations. Consciously or unconsciously, explicitly or implicitly, it will be considered.

[1] Staff reserves its right to respond to any additional issues not addressed in this brief that may be raised by other parties in their respective briefs on exceptions.

CPB continued this theme on page eight:

> The CPB considers this to be an extremely important issue for consumers because it highlights, starkly, the *dangers inherent for ratepayers in the holding company structure of utility ownership* that has become, and is likely to remain ubiquitous. Because *the holding company will inevitably decide direct allocation issues in the manner that provides the greatest benefit for shareholders*, the PSC should maintain a countervailing presumption in favor or an allocation favoring ratepayers.[2]

The issue that presents itself here, in contrast to the way the Commission typically considers a royalty adjustment and how Distribution's "Affiliate Rules"[3] are framed, is whether the Commission is able to ensure that a utility's rates are just and reasonable in situations where the utility's parent company makes decisions that benefit its shareholders at the expense of its regulated subsidiary's ratepayers. Staff recommends that the Commission institute a proceeding to examine both the decision-making of National vis-a-vis Distribution and an expansion of Distribution's woefully inadequate "Affiliate Rules" to protect Distribution's ratepayers.

Indeed, National is like no other combination company in the state. It is a complex holding company whose New York utility operation alone is under Commission regulation.[4] National has numerous activities including Pipeline and Storage, Utility, Exploration and Production, Energy Marketing and Timber. Due to the complexity of the corporate structure, and without access to the books and records of the parent or the non-regulated subsidiaries, Staff has to rely on responses to information requests provided by Distribution alone among the corporate entities to complete its evaluation of allocations of common costs and determine the reasonableness of these allocations. It almost goes without saying that Staff's and, thus, the Commission's understanding of National's allocations is incomplete.

The focus of the Commission's original royalty opinion (Case 87-C-8959) was on a utility's conduct toward its affiliated competitive enterprises. In that case, the Commission found that affiliates of Rochester Telephone Corporation benefited financially from using such

---

2 Emphasis added.

3 This document is attached as Appendix A.

4 See Appendix B, which shows the organization of the holding company system as of September 30, 2006.

ratepayer-funded assets of the telephone company as its name, logo, and employees who had been trained at ratepayers' expense. Start-up affiliates, moreover, were able to obtain lower cost financing due to their relationship to the healthy regulated entity that guaranteed the payback of the loans.

The Commission's second royalty opinion (Case 92-C-0665 et al., involving New York Telephone) confirms that the concept of royalty was generally confined to actions taken by the regulated entity. The Commission explained that the first 1% part of the royalty imputation can be avoided *if the utility agrees* that non-regulated affiliates will not be allowed to use such assets….; the second 1% part of the royalty imputation "can be avoided *if the utility agrees* not to transact business of any kind (other than transactions necessary for corporate governance) with any non-regulated affiliate.[5]

This focus on utility conduct is carried through in the "Affiliate Rules" document, which was attached to the Joint Proposals in Distribution's two previous rate proceedings. The document talks about limitations regarding "transfer of assets or the provision of goods or services..." by Distribution "to an unregulated subsidiary or an unregulated subsidiary to [Distribution]." There is discussion, for example, pertaining to non-discriminatory application of tariffed services and parameters by which personnel may be shared among affiliates. Section 4.0 is entitled "Goods, Services and Transactions Between [Distribution] and Affiliates." No explicit mention appears of situations where National is the active initiator and Distribution is the passive recipient. In fact, the "Affiliate Rules" document is silent on situations in which Distribution is acted upon by its parent.

Neither the Commission's royalty concept nor Distribution's "affiliate rules" pertain to a situation where the parent of a regulated utility makes decisions that benefit the parent at the expense of the utility's ratepayers**.** For instance, in the instant case, National made decisions regarding funding of pensions and distribution of insurance settlement proceeds in a manner that benefited National and had a significant impact on Distribution.

Another example: As part of Staff's justification for imposition of a royalty imputation, we assert that Distribution failed to demonstrate the reasonableness of executive pay per subsidiary for the rate year. Hearing Transcript (Tr.) 1357. In Staff IR 339 (Exh. 59), Staff asked: "For the rate year, provide the Executive/Officer base pay for each of the subsidiaries."

---

5 Emphasis added.

Distribution responded: "There is not a forecast of the executive/officer base pay for the subsidiaries in the rate year."

Staff asked in its IR 340 (Exh. 59; Tr. 1357): "In your answer to 339, how does NFG determine the reasonableness of the amount per subsidiary?" Distribution did not directly answer the question, responding in a tautological fashion instead:

> As explained in our response to DPS-339, we do not have a forecast of executive/officer base pay for subsidiaries for the rate year. Executive/officer base pay for subsidiaries has historically been reasonable as explained in the Company's response to DPS-181 and will continue to be reasonable in the rate year.

Furthermore, in its initial brief (at 104), Distribution remarks that Staff's reliance on these interrogatory responses is flawed because it:

> relates back to the 1995 case, where, the royalty was based in part on the Commission's finding that "NFG refused to provide its affiliates' forecasts…" Here, Distribution has not "refused" to provide its affiliates' forecasts. *The records* sought by Mr. Wojcinski—forecasts of executive compensation for the Rate Year—*simply do not exist*. The concept of a rate year is inapplicable to those companies and no Distribution affiliate would produce a rate year forecast of executive salary expense when it would not serve any business purpose. [6]

Putting aside the issue that the Commission considered Distribution's inability in 1995 to produce these forecasts as a "refusal," but according to Distribution should not do the same in this case,[7] Distribution has presented another example of how decisions by its parent that affect its subsidiary's ratepayers can be shielded from regulatory oversight.

Yet a further example of the limited reach of the "Affiliate Rules" to actions taken by the parent as opposed to the utility subsidiary is discussed in our initial brief. We explained Staff Initial Brief (S-IB) at 42-43) that under the tax agreement filed by National and its subsidiaries with the Securities and Exchange Commission, each subsidiary calculates and records its current federal income tax expense on a separate company basis without regard to tax losses of affiliated companies. To the extent that tax losses of individual subsidiaries reduce the

---

[6] Emphasis added.

[7] One assumes that the 2007 claim that unregulated entities have no business reason to prepare forecasts would apply equally in 1995.

taxable income of the consolidated group and result in the holding companying paying less income taxes to the federal government, amounts equal to the reduction in taxes are transferred to the loss companies by the holding company. The National agreement provided a “no strings attached recovery” for any tax loss generated.

Seneca benefits from this agreement, to the detriment of Distribution’s ratepayers, because it has substantial monies that it would not have received without the assistance of its sister subsidiaries. Since 1976, Distribution’s customers paid millions of dollars in rate allowances for federal income taxes that ultimately were not paid by either the utility or its parent. Instead, the agreement transferred these ratepayer payments to Seneca, a non-regulated subsidiary, for its tax losses. Absent the agreement, which would have resulted in Seneca being treated as a stand-alone subsidiary for tax purposes, Seneca would not have received payment for some of its tax losses, nor would it have received payment for some of its tax losses earlier than it did. Seneca is better off today as a result of the payment of its tax losses under the agreement. We ask the Commission to take notice of the favorable sale of Seneca Resources; Distribution’s ratepayers should share in the profits from this sale.[8]

Staff urges the Commission to institute a proceeding into the way in which Distribution’s parent makes and defends decisions that have significant impacts on Distribution and addressing whether the affiliate rules should be amended. The holding company structure has a tendency to impede the Commission’s ability to probe into decisions that may harm ratepayers. The royalty concept alone may not protect the integrity of the regulatory process. Perhaps another type of imputation mechanism, a corporate parent/utility subsidiary adjustment, is warranted so that the Commission is able to fulfill its statutory responsibility to ensure that Distribution’s rates are just and reasonable. Staff moves that the Commission issue an order to show cause designed to lead to an examination of these and related issues in regard to Distribution and National. At a minimum, the Commission should institute a proceeding that places on Distribution the burden of persuasion[9] that its “Affiliate Rules” are adequate to protect against situations in which its parent makes decisions that may have a harmful impact on Distribution’s ratepayers.

---

[8] An article discussing the sale is appended as Appendix C.

[9] The burden of persuasion encompasses the concepts of the burden of going forward and the burden of proof.

COST OF CAPITAL

Risk Profile

Contrary to the RD, Distribution's risk profile confirms the reasonableness of Staff's assumption of its hypothetical business profile score of "3." Business profile scores are assigned to companies to rank their relative business risk. Standard & Poor's (S&P) indicates that its utility business profile scores range from a "1" (excellent) to a "10" (vulnerable). S-IB at 3. Distribution is a wholly-owned subsidiary of National and issues no debt directly. As such, it has neither debt ratings nor a business profile score. National has a business profile score of "7" (moderately risky) and bond ratings of "BBB+" from S&P and Baa1 from Moody's. Staff's analysis determined that as a stand-alone utility, meaning a utility that would be individually rated, Distribution would have a split bond rating of "BBB+/A-" and a business profile score of "3."

On the basis of S&P capital structure guidelines (Exh. 52, Sch. 10), Staff determined that Distribution's hypothetical capital structure should reflect a 44.35% equity ratio. S-IB at 4. In contrast, the company determined that on a hypothetical basis, Distribution would have an "A-" bond rating, a business profile score of "4," and an equity ratio of 51.5%. RD at 4-5. The RD recommended that Distribution's hypothetical capital structure would have an "BBB+/A-" bond rating, a business profile score of "4," and a 47.25% equity ratio. RD at 6.

The reasonableness of Staff's assumption of a business profile score of "3" for Distribution is confirmed by a review of S&P's "U.S. Utility and Power Ranking List" dated April 27, 2007. Exh. 52, Sch.8, pp. 1-2. That exhibit shows that "2.9" is the average business profile score for the 24 transmission and distribution (T&D) utilities that have bond ratings comparable to Staff's assumption for Distribution, an "A-/BBB+" rating. Staff Reply Brief (S-RB) at 25. A review of 16 "A"-rated T&D utilities shows that only three (19%) have a business profile score of "4," as opposed to the remaining 13 utilities that have business profile scores of "1," "2" or "3." Further, a calculation of the average business profile score for the 23 "BBB rated" T&D companies in the exhibit is "3.65." These observations indicate that the majority of T&D utilities with investment grade bond ratings equivalent to a "BBB+" or higher have business profile scores no greater than a "3." Therefore, it is illogical to assume that Distribution, a regulated T&D company, with regulatory protections that include reconciliations and a weather normalization agreement (and a rate year revenue decoupling mechanism as part of its Conservation Incentive Plan or CIP), would have a more risky business profile score than T&D utilities with lower quality bond ratings.

Staff also notes that Exh. 52, Sch. 8 provides the business profile scores of other "New York State" (NYS) T&D utilities. Reviewing the groupings of the NYS utilities, by business profile score, revealed the following: KeySpan-Long Island and KeySpan-New York are classified under business profile score "1"; Consolidated Edison Company of New York and Orange and Rockland Utilities, Inc. are classified under business profile score "2"; and Central Hudson Gas & Electric Company and Niagara Mohawk Power Corporation are classified under business profile score "3." These groupings indicate that the rating agencies recognize that NYS T&D utilities have relatively low risk. It is more likely, consequently, that Distribution's operations would have risks similar to that of other NYS T&D utilities.

Finally, a review of S&P's business profile score graph (Exh.10, Sch. 2, Chart 2, p. 11 of 15) shows that nearly two-thirds of all transmission and distribution companies have business profile scores of "2" and "3," while only approximately 10% have business profile scores of "4." The RD provides no compelling reason to conclude that Distribution's risks are greater than the majority of T&D utilities. Accordingly, based on this discussion above, the better conclusion is that Distribution's most likely business profile score is a "3."

Common Equity Ratio

Distribution's common equity ratio should be no higher than 44.35% because the resulting rate of return does not penalize ratepayers for National's non-regulated risks. Using S&P guidelines and Staff's assumptions that as a stand-alone utility Distribution would have a "BBB+/A-" rating and a business profile score of "3," Staff determined Distribution's hypothetical common equity ratio at 44.35%. Then, as a reasonableness check, Staff conducted a subsidiary analysis, a method employed by the Commission in determining a subsidiary's capital structure. The subsidiary adjustment analysis showed that the removal of Distribution's parent's non-utility capital from its consolidated capital at 40% debt and 60% common equity resulted in regulated capitalization ratios (inclusive of customer deposits) of 58.37% debt and 41.63% common equity. On the basis of this check, Staff concluded that its 44.35% equity ratio recommendation was conservative. S-RB at 28.

On the other hand, based on its determination that, on average, a subsidiary's business profile score is equivalent to 60% of its parent, the company justified its assumption that Distribution hypothetically would have a business profile score of "4" (National's business profile score of “7” multiplied by 0.6 equals “4.2”). Based on the business profile score of “4,” the company justified its 51.5% recommended common equity ratio for Distribution. Distribution (D) -IB at 108.

The fallacy of the company’s analysis is that if the rating agencies adhered to the company’s algorithm, ratepayers would have to pay for the non-regulated risks of the utility’s parent through higher rates. For example, if National were to acquire KeySpan-Long Island, KeySpan-Long Island’s current business profile score of 1 would have to fall to a business profile score of 4, even though KeySpan-Long Island’s business risk had not changed. This is illogical and unfair to ratepayers who would be penalized for the additional non-regulated risks of the parent company.

This is the problem that will be faced by ratepayers if the Commission adopts the 47.25% recommended common equity ratio for Distribution. RD at 6. This higher equity ratio will penalize Distribution’s ratepayers for the higher risks that Distribution’s parent faces in its non-regulated businesses, which include, pipeline and storage, exploration and production, energy marketing and timber. Investors should receive the return on these non-regulated risks from the parent’s non-regulated operations, not from the ratepayers.

In addition, it should be noted that if a higher equity ratio is assumed for the regulated operations, then a lower equity ratio is assumed for the competitive operations. The RD's regulated equity ratio of 47.25% equity, as opposed to Staff's recommended 44.35% ratio, would reduce the assumed non-regulated equity ratio from 58.60 % to 57.10%.

Based on the above discussion, in order to develop just and reasonable rates, the Commission should adopt a common equity ratio for Distribution that is no higher than 44.35%.

Cost of Equity

The Commission should not deviate from its established 13-year standard for weighting the cost of equity methods for several reasons. These include: 1) the weighting of the DCF and CAPM ROE methods were analyzed in depth during the Generic Finance Case (GFC) proceeding; 2) for the past 13 years, the Commission has relied on the framework recommended by the co-facilitators of the GFC (S-IB at 5); and 3) the Commission has employed the 2/3rd DCF and 1/3rd CAPM weighting in determining the return on equity in all major gas and electric rate cases[10] that have been litigated.

Staff, in this proceeding, relied upon Commission precedent with respect to weighting the cost of equity results per the GFC methodology and had no reasonable basis to study, analyze and re-justify the weighting rationale for ROE methods in this proceeding. If the recommended 50/50-DCF/CAPM weighting is adopted, then the Commission would be making a critically important policy change without adequate notice to Staff or other parties to address the weighting issue, and would be adopting an inferior method of determining the return on equity. In effect, the Commission would be adopting a policy change without an adequate record. Any policy change should occur in a generic proceeding where a proper record can be developed with input from all interested and affected parties and not during a rate case or on an ad hoc basis. Therefore, Staff contends that the 2/3rd DCF and 1/3rd CAPM weighting of the GFC ROE methods should be maintained in this proceeding to determine Distribution's return on equity.

Market-To-Book Ratios

Market-to-book ratios are irrelevant in rate setting. Distribution considers the DCF Method to be unreliable because it understates the cost of equity when stocks are selling above book value. RD at 8. This relationship only matters to regulators if they plan to allow investors to earn what "they expect" (the return on market value/return on equity) as opposed to what "they require" (the return on book value/cost of equity). A market-to-book ratio above 1.00 indicates that investors expect the utility's "return on equity" to be higher than its "cost of equity." By allowing a utility to earn equity earnings equal to the cost of equity times the equity book value, regulators ensure that shareholders earn a fair rate of return.

---

[10] For example, see Opinion No. 96-28, Central Hudson Gas & Electric Corporation (Case 95-G-1034), wherein the Commission, in adopting the recommendation of the ALJ that the ROE be based on the 2/3rd DCF, 1/3rd CAPM methodology, found: "The weight he assigned to the DCF analyses—as compared with the CAPM, comparable earnings, and risk premium methods—properly reflects our settled policies concerning the relative merits of these approaches" (at page 13); and the Rate Order for Cases 02-E-0198 and 02-G-0199, Rochester Gas and Electric Corporation - Rates, wherein the Commission set the cost of equity based on the 2/3rd DCF, 1/3rd CAPM methodology.

CAPM

The CAPM has many flaws and overstates the cost of equity. S-IB 9, Hearing Transcript (Tr.) 231. The CAPM, used by both investors and companies, recognizes the close relationship between risk and return. It overstates, however, the cost of equity because it is sensitive to the higher business risks of the utilities' non-regulated businesses.

In Staff's analysis, there are three variables in the CAPM equation: 1) the risk-free rate; 2) the beta of a proxy group; and 3) the market return (from which the risk-free rate is subtracted to arrive at a market risk premium). Tr. 1113. The proxy for the first variable, the risk-free rate, is generally agreed to be long-term Treasury bonds. While analytical differences may exist concerning which maturities should be used, there is little controversy over the risk-free rate.

For the second variable, beta, Staff uses Value Line estimates. Beta is a measure of how correlated the proxy group's stock movement is to the market as a whole. Staff is aware that average utility betas have been increasing over the last few years, which have resulted in higher cost of equity determinations for utilities. It is likely that the observed increase in beta is due to utilities' non-regulated business; ratepayers should not compensate investors for this risk in their utility rates.

Specifically, over the past four years, average utility betas, as determined in CAPM analyses in Staff testimony, have increased from approximately 0.6 to over 0.9.[11] This means that return on equity calculations - the basis of the CAPM methodology - have increased by approximately 30% of the market risk premium (or about 1.8% given current market risk premium estimates). Such "non-utility business risk" leads to stock prices that more closely correlate to the market than to "utility only" investments.

A second indication that the utility betas are overstated is the fact that utilities have regulatory protections, reconciliations and make-whole provisions on about 90% of their revenues and, therefore, their risks differ significantly from the market as a whole. An explanation for this increase in the utilities' average beta and the increase in volatility of utility stock prices may be due to the utilities' increases in non-regulatory investments, their non-utility businesses. Ratepayers should not compensate investors for this in utility rates; it is a risk that the holding company's investors should be compensated for based upon the returns they earn from their parent company's non-regulated investments.

---

[11] The average beta of the companies in Staff's proxy group is 0.94. Exh.52, Sch. 3, p.1.

Analytically, this increase in utility betas has resulted in a divergence between the DCF and CAPM cost of equity results; that is, over time, the delta between DCF and CAPM cost of equity results have widened. The fact that utilities' non-regulated businesses have resulted in the calculation of higher betas, which have resulted in higher CAPM cost of equity results than is required by the utilities' regulated business, actually may require a lower weighting of the CAPM relative to the DCF.

Finally, the third variable, the market return which is used to calculate the market risk premium, is also controversial. Some parties use historical premiums, which may not reflect current conditions. In the alternative, other parties use forward-looking estimates which may be flawed based on forecasts and which sometimes change rapidly.

The Commission's weighting of the DCF and CAPM cost of equity results reflects its recognition that the CAPM methodology, at least when applied to utility cost of equity measurements, has flaws that exceed any potential flaws in the DCF methodology. A CAPM weighting equal to that of the DCF would result in ratepayers compensating investors for the investors' risk in the parent company's non-regulated investments. Accordingly, the CAPM weighting should remain at one-third.

DCF

The DCF method is the most prevalent cost of equity method used by utility regulatory commissions and should have a higher weighting than the CAPM in determining Distribution's allowed return on equity. It is apparent that the flaws in the CAPM variables have resulted in CAPM utility cost of equity results that are too high. Many of the concerns related to using the CAPM for determining a utility's cost of capital have led most state commissions to rely primarily on the DCF method. The DCF is the most frequently used method in estimating a utility's cost of equity and is usually given the most "weight" by regulatory commissions.

This assertion is confirmed by survey results that were provided in an article entitled "Estimating the Cost of Equity: Current Practices and Future Trends in the Electric Industry."[12] Of the 25 commissions that took part in the survey, 24 (96%) used the DCF method

[12] Dangerfield, Byron Merk, Lawrence H. Narayanaswamy, "Estimating the Cost of Equity: Current Practices and Future Trends in the Electric Industry," Engineering Economist**;** December 22, 1999.

with an estimate of future dividends.[13] Sixty-eight percent of the commissions used the CAPM, but in every instance it was used in conjunction with the DCF model. In addition, one-quarter of the commissions used a comparable earnings approach as well, and 36% used a risk premium approach related to historic bond yields in addition to whatever other methods they used.

The survey results indicate that the DCF cost of equity methodology is by far the most prevalent and validate the Commission's current weighting of cost of equity methods of 2/3rds DCF and 1/3rd CAPM in its determination of utilities' allowed return on equity. Staff recommends that the Commission maintain its current weighting.

RDM Adjustment

On the basis of Staff's 13-company proxy group and its RDM proposal (S-IB at9), Distribution's cost of equity determination should be reduced by a full RDM adjustment in the range of 16 bps to 25 bps. The full adjustment is required because all but one of the companies in Staff's proxy group had neither a CIP nor or a weather normalization adjustment (WNA), and so the proxy group's resultant cost of equity reflected the higher risks of the proxy group relative to Distribution, which has a WNA and which will also have an RDM in the rate year. With the melded proxy group (RD at 11), 5 of the 18 companies (27.7%) of the proxy group companies have a CIP and/or a WNA. Therefore, if the melded proxy group is adopted, Staff's proposed RDM range of 16 bps to 25 bps should be reduced by 27.7%, to a range of 12 bps to 18 bps.[14]

---

[13] Staff also employs a DCF model that uses a two-stage dividend growth assumption to reflect investors' short-term expectations and longer-term assumptions. This provides a blended growth estimate that more closely aligns with investors' expectations.

[14] The company also proposed a 25 bps RDM adjustment. However, the application of the RDM adjustment differed because of the variance between Staff's and the company's proxy groups' composition. That is, 92% of the companies in Staff's proxy group did not have either a CIP and/or a WNA, and so Staff applied a negative 25 bps RDM adjustment to the proxy group's resultant cost of equity because Staff's proxy group's higher risks yielded a higher return than that required by a Distribution with a CIP/RDM. On the other hand, 70% of the companies in the company's two proxy groups had either a CIP and/or a WNA and, therefore, after adjusting for the fact that Distribution also had a WNA, the company recommended that a positive 10 bps RDM adjustment be applied to its proxy groups' resultant cost of equity if Distribution's CIP was not adopted and no RDM adjustment if it was adopted. The company's positive adjustment reflected the lower risks of its proxy group relative to a Distribution without a CIP/RDM. Tr. 189-90.

EXPENSES

Employee Count and Productivity Adjustment

The RD adopted Staff's weekly and management labor complement adjustments with the following caveat: "However, this adjustment should serve to capture all the potential rate year productivity that can reasonably be expected and it is not reasonable to apply another, one-percent productivity adjustment on top of this one." RD at 14. Therefore, the RD concluded: "Given that Staff has proposed 54 less (sic) positions for the rate year using an overall measure of its workforce needs, there does not appear to be any substantial and independent basis for the Commission to apply its standard adjustment in this case. Accordingly, I do not recommend that there be a one-percent productivity adjustment in the circumstances presented in this case." Id.

This conclusion is in error. The purpose of Staff's recommended labor complement adjustment is to forecast the complement level in the rate year. That is, it is a specific "known" item forecasted out into the rate year. The Commission's standard 1% productivity adjustment is to capture unknown and unquantified productivity savings that are not explicitly identified in the rate year such as in the areas of information services and transportation costs. Accordingly, the 1% productivity adjustment is entirely appropriate.

Management Rate Year Pay Raise

The RD (at 16) rejected Staff's proposal to allow management the same percentage pay raise as the union employees. The RD states that Staff did not provide a well developed basis for this position. Staff's proposal is not only consistent with the Commission's decision in a previous Distribution rate proceeding[15] (Tr. 1263), but it also is entirely consistent with Commission practice. Nothing in the record shows that management receives lesser benefits or that the company has more difficulty attracting competent managers than competent weekly workers. Therefore, the Commission should adopt a management pay raise similar to that given to weekly employees.

Lump Sum Payments (LSP)

The RD states (at 16): "In addition to the base salaries that management employees receive, NFG also provides its managers lump sum compensation." While this is not

[15] Cases 94-G-0885 and 93-G-0756, National Fuel Gas Distribution Company – Rates, Opinion No. 95-15, Order Determining Revenue Requirement and Rate Design (issued September 15, 1995), pp. 18-21.

technically wrong, it is a mischaracterization. As discussed in Staff testimony (Tr.1265), citing (Case 04-G-1047, Rebuttal Testimony of Sarah J. Mugel) a LSP "is a way to manage base pay." As an example:

> Assume in year one a management employee receives a $100 pay raise and Distribution allocates this pay raise $30 to base pay and $70 as a LSP. The $70 LSP is a one-time lump sum compensation payment, and it is not an incremental part of compensation. Under this example, the employee would receive part of his year one pay raise as a LSP, and in year two this $70 amount is gone. The employee does not receive this year one amount again in year two or in the future.

The LSP is further explained with a hypothetical example from year 1 to year 2 in Exh. 26 (Responses to IRs 466, 467, 468, 469 and 470). IRs 467 and 468 describe a situation where a Distribution management employee received his entire pay raise as a base payroll raise, with $0 LSP. Staff proposed Distribution's management rate year pay raise as an increase to base payroll. Therefore, the rate year LSP is $0. Staff did not allocate the proposed pay raise between base pay and LSP. Accordingly, to also include an amount as a LSP would grant the company this amount twice.

Executive Retirement Plan (ERP)

In recommending against Staff's proposed adjustment, the RD concluded (at 20) "that nothing more than a paragraph is offered by Staff in its brief to allege that the executive retirement plan is discriminatory and that an equivalent of productivity should be considered to offset the cost of the retirement plan." More supporting information is readily available.

The ERP is a Defined Benefit Pension Plan available to various Distribution Officers, at the discretion of Distribution's Parent's CEO. Tr. 1273. The latest ERP Actuarial Report prepared in December 2006 "Actuarial Report for FAS Statement No. 87 for the Accounting Period Beginning October 1, 2005 and Ending September 30, 2006" states on page 5 that under the plan's provisions a "Covered Employee" is any employee designated by the Chief Executive Officer of National Fuel Gas Company. Identified on page 10 of this report are 16 active and 22 retired plan participants in the ERP. Thus, the company is requesting an annual expense allowance of approximately $900,000 to fund an ERP for 16 active employees.

The last fully litigated Distribution rate proceeding was Case 94-G-0885, Opinion No. 95-16 (issued September 15, 1995). In that rate proceeding, the Commission did not grant a rate allowance for ERP. Since then, the company and Staff have entered into several joint proposals where as a compromise these settlements variously did, and did not, include an ERP allowance. However, it has always been, and continues to be, Staff's position, as well as Commission practice, that an ERP allowance is not reasonable.

Site Investigation and Remediation - SIR

Staff's proposal regarding disposition of the proceeds from the settlements with various insurance carriers is founded on the proposition that such disposition should be proportional to the insurance claims made or losses incurred. The premiums paid method does not accomplish this, which the company does not refute. Simply put, the premiums paid allocation method not only flies in the face of common sense but also would result in unjust and unreasonable rates.

The RD nevertheless concludes "… that the 'premiums paid' allocation is not unreasonable on its face and that no party to the proceedings has provided any more reasonable allocation factor that could have been used in 1999. Accordingly, I do not recommend that the Commission accept the Staff proposal to attribute to NFG $14.6 Million more of the insurance proceeds obtained in 1999 by the parent company." RD at 35. Staff disagrees. The RD's flawed reasoning is, perhaps, based on an incomplete understanding of the sequence of events and the nature of the decisions taken by National.

Under girding the RD's conclusion is the application of the wrong standard of review. This is not a prudence investigation where the standard of review is whether "the parent company acted reasonably in the circumstances presented at the time of its decision in 1999." RD at 33. Assuming for the sake of argument that it was a reasonable decision in 1999 to eventually allocate Distribution 45% of the proceeds even though the potential liability was estimated at 64%, the critical aspect of this issue is that the decision was not irrevocable. The decision did not cause a chain of events, such as purchasing inferior material or failing properly to oversee contractors in the construction of a power plant already completed at the time of the prudence investigation, that could not be undone. Rather, it was National—and National alone—that consciously decided not to revisit the allocation issue as site remediation occurred over the next eight years or so.[16]

[16] The RD swallows another red herring in stating that "there is no explanation for why this matter was not presented at an earlier date." Id. As discussed in our reply brief (at 23), it was only in this proceeding, after review of the actual SIR claims compared with the AEGIS policy through August 2006 (Exh. 54, Sch. 2), that Staff became aware of the gross disparity between premiums paid by Distribution and remediation costs incurred by Distribution.

Here is a simple review of the issue:

- ✓ A 1996 environmental study shows that **64%** of the potential clean-up costs associated with National's SIR were attributable to Distribution.
- ✓ Between 1996 and 1999,National obtains cash settlements from its insurance carriers regarding SIR cost reimbursement; National also obtains a new AEGIS policy in 1998.
- ✓ In 1999 National decides to allocate to its subsidiaries the proceeds based on their proportional share of premiums paid, rather than based on the report's projections, providing Distribution with a **45%** share.
- ✓ SIR insurance proceeds were received under the AEGIS settlement from 1998 through 2006. Over the years it becomes apparent that Distribution accounts for **85%** of the claims.
- ✓ There is absolutely no evidence in the record or in the public domain, nor is there any law or regulation supporting the claim that National was precluded from revisiting its 1999 decision as facts on the ground became known and that remediation costs had to be reimbursed in the order expensed.

Reimbursement For SIR Losses

The premiums paid allocation methodology elected by Distribution's parent does not attempt to reimburse each subsidiary for its SIR losses. It is commonly understood that the purpose of obtaining insurance is to have protection when a loss occurs. No one expects to receive proceeds from their insurance carriers just because they have paid insurance premiums. Yet, the company (and the RD) does not agree with this generally accepted concept. Instead, the RD finds it reasonable that National would allocate the SIR insurance proceeds based on past insurance premiums paid, which resulted Distribution receiving only approximately 45% of the total SIR insurance proceeds.

However, the fact is that in 1999 National knew that according to the 1996 environmental report (IES report), 64% of the SIR costs were projected to be attributable to Distribution. Tr. 1289. Yet, armed with this information, National did not reasonably elect to allocate 64% of the monetary settlement proceeds to Distribution, but, instead, elected a methodology that allocated approximately 20% less. This methodology unreasonably allocated millions of dollars away from NY Distribution, which resulted in ratepayers paying for the 20% difference.

Additionally, the 64% figure is further skewed since the remaining 36% of potential non-Distribution SIR liability includes $71 Million of National Fuel Supply Corporation's potential SIR liability whereas the record evidence reveals that less than $2 Million was ever claimed by Supply. Excluding the $71 Million from the total 1996 estimated liability of $353 Million, results in approximately 80% of the SIR liabilities being attributable to NY Distribution. Staff-IB at 38-39.

Timing of Allocation Decision

The "irrevocable" decision regarding allocation of SIR insurance proceeds did not have to be made in 1999. As stated above, National received the SIR cash monetary settlement proceeds through 1999 and should have allocated at least 64% of these proceeds to Distribution. SIR insurance proceeds were received under the AEGIS settlement from 1998 through 2006. A wiser approach would have been to wait to see how the SIR situation developed rather than rigidly sticking with the 1999 decision.

The only reason the company offered for its assertion that the claims method would not have been fair is that one subsidiary might have grabbed all of the proceeds with a big claim. But this argument is disingenuous, since there were never any potential large environmental liabilities identified in any of National's annual reports to stockholders or the Security and Exchange Commission. Exh. 26, response to DPS-457.

While Distribution claims that its methodology was reasonable based on a hypothetical scenario where a claim from another subsidiary filed before Distribution would thereby wipe out the proceeds, this hypothetical not only did not happen, but was never going to happen. Distribution does not dispute that NFG Supply's potential liability was greatly inflated and nowhere in the record is it established that a PA-Distribution claim would have superseded a claim by NY Distribution. Further, nowhere is any such "first come, first served" rule mandated by accounting rules or Commission precedent. It is a "rule" now created by Distribution to after-the-fact support its claim that the allocation methodology was reasonable. If, in fact, such a scenario became an actuality, National could then have reconsidered its allocation methodology to ensure that other subsidiaries with SIR potential liability received their share.

The allocation of the insurance proceeds under the Aegis Policy should have been similar to calculation of Federal Income Taxes for rate making purposes, which assumes the company is a stand-alone company and is not affected by other subsidiaries. Under this premise, the subsidiary that made SIR insurance claims should receive reimbursement for its claims.

Royalty

In our initial brief (at 41-46), we offered five examples of decisions made by National that benefited its shareholders to the detriment of Distribution's customers. As a consequence, we suggested that a royalty adjustment of $1.6 Million was appropriate. The RD did not discuss any of these examples. Instead, it suggests that a royalty adjustment is tantamount to being old-fashioned. RD at 45.

In considering Staff’s five examples of misallocations of costs and benefits that amply support this adjustment, two observations help place our recommendation in context. First, Staff’s pre-filed testimony in the proceeding that resulted in a “black box” Joint Proposal detailing Distribution’s current rate plan (Case 04-G-1047) recommended a royalty imputation of $8,984,000. Second, Staff’s current royalty adjustment of $1,531,000 is justifiable on the sole basis that Distribution lost interest of up to $5 Million due to the allocation method chosen by National to divvy up proceeds from SIR insurance settlements. Tr. 1403.

The five examples that support the royalty adjustment are compelling. First under the tax agreement filed by National Fuel Gas Company and Subsidiaries with the Securities and Exchange Commission to Rule 45c of the Public Utility Holding Act of 1935, each subsidiary calculates and records its current federal income tax expense on a separate company basis without regard to tax losses of affiliated companies. To the extent that tax losses of individual subsidiaries reduce the taxable income of the consolidated group and result in the holding companying paying less income taxes to the federal government, amounts equal to the reduction in taxes are transferred to the loss companies by the holding company. The National agreement provided a “no strings attached recovery” for any tax loss generated.

Even until its recent sale, Seneca benefited from this agreement, to the detriment of Distribution’s ratepayers, because it has substantial monies that it would not have received without the assistance of its sister subsidiaries. Since 1976, Distribution’s customers paid millions of dollars in rate allowances for federal income taxes that ultimately were not paid by either the utility or its parent. Instead, the agreement transferred these ratepayer payments to Seneca, a non-regulated subsidiary, for its tax losses. Absent the agreement and thus being treated as a stand-alone subsidiary for tax purposes, Seneca would not have received payment for some of its tax losses, nor would it have received payment for some of its tax losses earlier than it did. Seneca is better off today as a result of the payment of its tax losses under the agreement.

Second, assuming the company is consistent with its policy to reimburse subsidiaries that incur financial losses as provided for in the company's tax agreement, the disbursement of insurance should be made in a similar manner. However, that is not the case for $37.3 Million in SIR clean-up insurance proceeds. National allocated the proceeds to all its subsidiaries based on insurance premiums paid in the past. Under the parent company's allocation, Distribution receives approximately 46% of the insurance proceeds, yet incurred 85% of the environmental costs. The primary source of the claims, moreover, is Distribution and, therefore, unlike payment of Seneca's tax losses from its sister subsidiary, Distribution is the subsidiary that had substantial insurance losses and is also the subsidiary that allowed the parent to recover the entire $37.3 Million.

Staff has made the claim for the $37.3 Million as a separate adjustment. However, as a result of the unfair allocation of insurance that goes back to the year 2000, Distribution lost up to five million dollars in interest if it had received those payments on a timely basis.

Third, there is controversy between two regulated jurisdictions, New York and Pennsylvania, regarding the allocation of capital in the calculation of the EB/CAP. The company claims:

> Because of the two different rate jurisdictions the capitalization of the total company has been allocated based upon the determination of Distribution's total Earnings base. This is not a proper allocation of capitalization due to different way items are treated by the two Commissions.[17]

This situation is National's own fault for not separating the NY-Distribution and PA-Distribution into separate entities. National is simply not doing everything it can to eliminate the risk of improper allocations in order to avoid the royalty adjustment.

Fourth, allocation of common costs is an issue. Administrative and general salaries and office supplies and expenses of general nature (common costs) that affect the operation of subsidiary companies of National are allocated to the appropriate company or service area. These costs are located in the Distribution company and are allocated to other subsidiaries based on various factors, one being the Total System Allocation Factor (TSAF). TSAF is calculated by taking an average of five factors. These are: Total Gross Plant,

[17] Tr. 1355.

Total Net Plant, Total ThroughPut, Number of Employees and Operation and Maintenance Expenses. This allocation was approved by the Commission in Case 28447. Tr. 1356.

There is a problem, however, with the calculation of one of the factors. The Total ThroughPut factor of TSAF shows no sales for unregulated subsidiaries. The company claims that under the strict definition for throughput, there were no sales in its unregulated subsidiaries. However, in Case 28447, the Commission determined that sales were to be a component in the TSAF and its non-regulated subsidiaries do make sales. Tr. 1356-57.

Finally, in order to demonstrate the reasonableness of total rate year executive pay by subsidiary (there are common allocations of executive pay),Staff requested that the company provide such information but the company refused. Instead, as discussed earlier in this brief, we were effectively told to trust the company that the level would be reasonable in the rate year. Exh. 59, Responses to DPS 339, 340.

We addressed the relevance of the Affiliate Rules earlier. We also discussed the fact that the Commission's royalty decisions did not contemplate situations in which the utility subsidiary is the passive recipient of decisions by the corporate parent rather than the decisive actor affecting its own subsidiaries. With this more sophisticated appreciation, we believe that instead of calling our proposal a “royalty” adjustment as it has historically been called in Distribution's previous rate cases, it should be considered a “corporate parent/utility subsidiary” adjustment.

In thinking about the company's comments on the issue and the deleterious impact of National's decisions on Distribution's customers, we conclude that our proposed adjustment is modest, perhaps irresponsibly so.[18] However, such an adjustment would go a long way towards establishing just and reasonable rates for Distribution. Finally, even if none of Staff’s five arguments would warrant a royalty adjustment of $1.5 Million, an adjustment should be made upon the reversal of the RD’s position on SIR insurance proceeds. That unfair allocation resulted in a loss to Distribution ratepayers of approximately $5 Million of interest.

[18] The foregone interest on the proper allocation of insurance proceeds to Distribution, alone among the five examples, is a not inconsiderable $5 Million.

RATE BASE

Pension Payments

National/Distribution did not follow the Commission's policy statement on this issue and, accordingly, no return should be allowed. The company requests rate base treatment for the payments made above allowances in rates and the interest accrued on those payments, the total of the two make up a debit balance. The Commission's Policy Statement on Pension and Other Post Employment Benefits (OPEBs) requires that the company demonstrate that they needed to make funding above rate allowances, to the external pension fund, in order to accrue interest on the debit balance. No funding above rate allowances should be made unless the external pension fund's tax effective status would be impaired.

The company's expert witness made it clear that funding above rate allowances was not necessary to allow the external fund to maintain its tax effective status. It is interesting to note that the RD (at 50) incorrectly states: "Had the Company stuck to its minimum funding requirements, Staff believes that the funds in the external trust would have been adequate." This is not Staff's belief. Rather, it is the company's expert witness who came to this conclusion. Exh. 59, Response to Staff IR 364(b). There never was a need to fund above rate allowances and, therefore, interest or rate base treatment should not be allowed.

Not only was the external pension fund adequately funded at the end of June 30, 2006, it is in fact over funded by $212 Million. Thus, it would take a drop in the funds value by that amount before any ERISA minimum funding would be necessary.[19] And even at the point in time (year 2002), when the company decided to fund more than allowed in rates, and in the following periods, the external pension fund was more than adequately funded under ERISA requirements. This ERISA over funding (from Schedule B, Form 5500 and annual actuarial reports) is shown in the table below:

Plan Year Ending:	Over/(Under Funded)
June 30, 2006	$212,724,338
June 30, 2005	$187,053,741
June 30, 2004	$163,820,621
June 30, 2003	$128,509,414
June 30, 2002	$ 95,777,614

19 See Appendix D, which consists of Schedule B (Form 5500) for 2004 and 2005.

Staff agrees with the RD's conclusion that "NFG should neither be penalized nor rewarded for the actions it took to fund the external trust at a proper level." Staff's proposal, using Cost Mitigation Reserve (CMR) monies and the $16.1 Million rate year pension expense allowance to offset the debit balance, does just that. Contrary to the RD's recommendation, no interest accrual is appropriate, since the company did receive a benefit (reward) in the past from making funding above rate allowances to the external pension fund. The additional pension funding payments allowed Distribution to tax effectively fund an additional amount to its external OPEB fund, and thus reduce its internal OPEB fund that is accruing interest at the pre tax rate of return.

Disposition of the debit balance is not fully addressed in the RD. The deferred debit pension balance consists of the funding to the external pension reserve, above rate allowances, and the interest accrued on those payments ($4.5 Million). For funding above allowances in rates, the company would use pension rate allowances to recover these dollars. However, the disposition of the interest component of the deferred debit should have been addressed by the company in this case (Exh. 26, Response to IR 415), but it failed to do so. Since Distribution has not addressed this item in this proceeding, it should be precluded from recovery for this item in the future.

REVENUE-RELATED ITEMS

Late Payment Charges

The RD concluded (at 55) that "…Staff has not demonstrated that there is an adequate basis, as a matter of law, for the Commission to direct NFG to cease its current practice" of applying and collecting late payment charges (LPCs) on the arrears portion - unpaid balance and accumulated interest - of a deferred payment agreement (DPA). This conclusion ignores the Commission's statutory obligation to ensure that utility rates are just and reasonable.

Distribution's practice to apply such charges, resulting in revenues of $4.25 Million, contravenes Commission policy stated in Case 99-M-0074.[20] In that proceeding, the Commission decided that the imposition of a late payment charge on the arrears portion of the

[20] Case 99-M-0074, Proceeding on Motion of the Commission to Investigate the Application of Late Payment Charges to Deferred Payment Agreements for Residential Customers, Order Directing Utility Filings (issued January 22, 1999).

bill that has been restructured by entering into a DPA is disfavored and should not be allowed, so long as the newly restructured monthly bill is timely paid. While the Commission ordered compliance or an explanation as to why a utility should be allowed to apply LPCs, and Distribution did provide its explanation that Public Service Law (PSL) §42 permits it to do so, Distribution remains the only utility in New York State to so assess LPCs. Tr.1056. The Commission should not follow the RD's recommendation, but, instead, should ensure that its policy is followed by Distribution by not allowing Distribution to collect LPCs on arrears when customers are making timely payments under a DPA.

Staff initially proposed reducing the amount of uncollectibles by $4.25 Million (Tr.1058) based on the information provided by the company. Upon further reflection, Staff now recommends setting a 50% adjustment to the historic average annual amount of LPC charges included in uncollectibles, or $2,125,000, and update the uncollectible formula in September 2008 as a proxy for the rate year uncollectible expense. Any difference between the actual and any estimate will be recovered from or credited to the CMR. If there is not sufficient monies to recover a shortfall, then the difference would be deferred until the next rate case.

LICAPP Surcharge Mechanism

The RD (at 56) recommended approval of Staff's proposal concerning increased funding and surcharge mechanism. However, the RD did not specifically address Staff's proposal that the Low Income Customer Affordability Assistance Program (LICAAP) costs should be recovered in the rates of all customers, primarily because it promotes the public interest described in HEFPA of maintaining essential service for customers at risk of losing service, and also because of the benefits of the program to ratepayers and taxpayers. Tr. 1052. While this issue was not specifically addressed in the RD, no party has disputed Staff's proposal, and therefore, it should be adopted.

Staff recommended a $365,000 downward adjustment for duplication in the Distribution's outreach and education program regarding energy conservation. Tr. 1060-61. However, the RD states that Staff proposed that $36,500 be removed from the company's general budget to eliminate an overlap. The amount should be corrected from $36,500 to $365,000.

CONSERVATION INCENTIVE PROGRAM

By Order Adopting Conservation Incentive Program (issued September 20, 2007), the Commission established Distribution's energy and efficiency program (CIP) for the 2007-2008 heating season, with a collaborative scheduled for early 2008 to fine tune the CIP for the 2008-2009 heating season. Staff proposed the use of a surcharge to collect the costs of the program from all ratepayers, to which no party objected, except MI, which argued that large-service industrial gas transportation customers should not have to pay for a program that will not directly benefit them. The RD accepted MI's position.

Staff takes exception to the RD on this issue. The societal benefits of energy efficiency were noted by the Commission in the order initiating the EPS Proceeding. In addition, improved air quality has a positive effect on health, which translates to fewer sick days and less drain on health care resources. These benefits will improve MI's clients' bottom line.

INCENTIVES

The RD did not clearly explain its conclusion regarding system safety performance standards and incentives versus the conclusion regarding the customer service standards and incentives. RD at 65-66. Although Staff believes the RD (at 61) intended to adopt both of Staff proposals, needing clarification is the recommendation (at 66) that the Commission adopt the Staff proposal because "…Staff does not propose to change the targets and the amounts of the monetary incentives or penalties…."[21] Staff believes this specific recommendation was intended to refer to only the Staff position on the customer service incentives which were not proposed to change, because as noted in the RD at 61, Staff's proposed safety targets and incentives do represent a change compared to the company's current program. Staff's proposed targets are more realistic and still at levels that are within the company's currently achieved performance levels.

Also, while not specifically addressed in the RD, the time period these safety targets and incentives would remain in effect until changed by the Commission. Tr. 1207-08. This would ensure that the company continues to achieve or exceed the standards and not backslide during an extended stay out.

---

21 The concept of "incentive" encompasses both negative and positive repercussions. Thus, it is redundant to speak of "incentives and penalties."

RATE DESIGN MATTERS

Revenue Allocation and Rate Design of Delivery Rates

The RD has recommended a $2.00 increase to the existing monthly minimum charges of the residential service classes including SC 1 Residential Service and Service Classification No. 2 (SC 2) Low Income Residential Assistance (LIRA) Service. RD at 68. We do not necessarily oppose this level given the significantly reduced rate increase recommended by the RD. Nor do we oppose the majority of the company's revenue allocation and rate design proposals if a rate increase is determined to be necessary by the Commission. Our support for a revenue requirement for Distribution, however, that results in a rate decrease determination warrants a review of the Staff position for both a rate increase and rate decrease determination because the RD did not address the recommended rate design in the event of a rate decrease.

Rate Increase Scenario

We support the company's proposed revenue allocation and rate design process based on the results of a four-step process. In Step 1, the rate increase should be allocated to the service classes based on the historic proportion of non-gas revenue for each service class. This is methodology fairly distributes the overall increase to all service classes and is similar to the revenue allocation methodology that was adopted by the Commission in Distribution's last rate case resolution. S-IB at 50-51.

In Step 2, the recovery of the proposed delivery rate increase for individual service classes should be determined. We supported the company's proposal to recover the entire allocated increase through the minimum charges of the existing residential classes including SC 1 and SC 2. Given the level of rate increase recommended by the RD, we believe his proposed minimum charge increase is an adequate movement in the direction of the associated minimum costs to serve for these classes.[22] S-IB at 51-52.

We also support the company's proposals to recover the rate increase from the non-residential classes in the following manner: For Service Classification No. 3 (SC 3) General Service, Service Classification No. 13 (SC 13) Transportation Categories TC-2.0 and TC 3.0, the allocated increase should be recovered 50% through minimum charges and 50% through the

[22] Staff continues to support a determination of the minimum costs to serve a residential customer be consistent with previous Commission practice of excluding costs associated with the distribution mains. S-IB at 52-53. In Distribution's case this would result in a minimum cost to serve of $19.12 per month. S-IB at 52. The RD did not address the merits of this issue.

volumetric block rates. For SC 13 TC-1.1, the entire allocated increase should be recovered through the volumetric block rates. For SC 13 TC-4.0 and TC-4.1 the allocated increase should be recovered by increasing the existing minimum charges for each of these transportation categories to $3,827.24, based on cost of service study results, with any remainder of the increase recovered from the volumetric block rates. Staff supports these proposals because the majority of the proposed changes to the non-residential sales and transportation service categories allocated the increase primarily to the minimum charges. We continue to believe these are acceptable rate designs for the larger customers in these classes since they are more sensitive to changes in volumetric rates as opposed to movements in minimum charges towards cost. S-IB at 52. However, we must caution that because of the small revenue increase recommended by the RD, the revenue increase recovery proposals, primarily through minimum charge increases that we support here, both for the residential and non-residential classes, would likely result in the need to decrease volumetric rates in order to achieve the proper revenue requirement.

In Step 3, we support only Distribution's proposed redesign of residential service class block rates where tail block rates were reduced and penultimate block rates were increased.[23] This is consistent with the Commission's Order Requiring Proposals for Revenue Decoupling Mechanisms,[24] where the Commission stated that implementation of fully cost-based rates is another means of eliminating utility disincentives to promote conservation programs. The proposed redesign moves the existing SC 1 rate design in the direction of cost to serve without creating any large impacts.

Although the proposed decrease to the tail block rate would reduce the savings provided to customers that conserve energy, it is an acceptable interim movement of fixed cost recovery to earlier charges in the SC 1 rate structure, since the customers' primary incentive to conserve continues to be the cost of the gas commodity itself. In addition, these rate redesigns result in a tail block rate that is within the range of the similar rate blocks at the other major upstate gas utilities. S-IB at 53-54. In Step 4, we support recognizing that the proposed residential rate reallocation in the above Step 3 will lead to a migration of existing SC 3 General Service "religious" accounts to SC 1 Residential Service. S-IB at 54.

---

[23] We support the RD's recommendation that the Commission not adopt Distribution's proposed alternative methodology for recovery of purchased gas demand costs. RD at 69-70.

[24] Issued April 20, 2007 in Cases 03-E-0640 and 06-G-0746 (RDM Order), p. 7.

Rate Decrease Scenario

For SC 1 and SC 2 residential service classes, we support continuing the movement in the level of the minimum charge toward cost. S-IB at 54. Thus, the RD's recommended $2.00 increase in the minimum charges of these classes is acceptable to Staff. Accordingly, the penultimate and tail block rates for these classes should first be reduced on a per unit basis to offset the increase in the minimum charges and then further reduced on a per unit basis by the allocated portion of the revenue decrease determined by the Commission. S-IB at 54-55. For the other service classes, we support keeping minimum charges at current levels so as not to further frustrate movements toward the indicated cost and any allocated decrease should be applied to the existing volumetric rates of the service classes affected. S-IB at 55.

The "No Harm, No Foul" Rule

The RD recommends that the Commission consider an approach that is somewhere between the positions taken by Distribution and CPB, on the one hand, and Staff and MI, on the other. It further states that the daily balancing requirements should be applied separately to two groups, one consisting of the large marketers and another made up of the smaller marketers, each having the benefit of its own "no harm, no foul" rule. RD at 73.

Creation of an additional transportation balancing pool would be administratively burdensome and would be a step backward in the evolution of efficient and effective transportation and balancing procedures. Distribution was one of the last companies to implement a workable daily balancing service and continues to take actions detrimental to the growth of this service. The existing daily balancing procedures are already more stringent than the company's ability to identify its own daily balancing performance. The company utilizes no notice/enhanced storage to handle all of its balancing swings on a daily basis and was unable and unwilling to produce records of its own performance.

The marketers in question are all large marketers serving customers with annual usage greater than 25,000 MCF annually. The term "small marketer" is relative. Marketers serving retail access customers under 5,000 Mcf annually are not eligible for this service. The large marketers supposedly bearing the burden of this perceived and fabricated inequity are not complaining. In fact, these customers are represented by MI and favor keeping the rule in place.

Large marketers enjoy the ability to operate outside the 10% operating band when small marketers bring the entire pool within the tolerance limits. No one has an advantage relative to size. As long as daily balancing occurs within the established tolerances and no problem exists with the daily results, there is no inequity. A separate "no harm, no foul" rule, applied to the smaller marketers as a group (excluding the large marketers) is not necessary because the same rules already apply to them with the same amount of force and to the same degree that it applies to the large marketers. All marketers face an end of month cash out regardless of either individual or pool performance. This monthly cash out back to the 0% level is self-policing and rectifies any actual or perceived advantage. There is simply no need to have separate daily balancing requirements, and such a recommendation should not be adopted by the Commission.

UNBUNDLED DELIVERY AND COMMODITY COSTS AND CHARGES

Billing Charges

The RD observes (at 82) that "bills should be kept as simple as is reasonably possible" and that "comparable billing statements for customers that permit them to make comparisons of meaningful and useful information" is an important goal in designing customer bills. And yet, the RD recommends that the Commission grant "a waiver of any provision of the Unbundling Order" to accomplish exactly the opposite effect.

Distribution has been conducting consolidated billing for ESCO services wrong for several years. It has been billing customers directly for utility consolidated billing, where the Commission's orders in the billing and unbundling proceedings have clearly indicated that ESCOs should be paying. Distribution has, in essence, been giving ESCOs a free ride for billing for them. Now, the company seeks to compound this error by adding another wrong on top of the first one by rebundling the billing charge back into the monthly customer charge. Two wrongs do not make a right and Distribution should not be allowed to make this compounded error.

Distribution claims that the separately stated billing charge has confused customers. However, it is the company's own insufficient customer education and its improper application of the charge that has led to this result. The separate statement of the billing charge has been implemented throughout New York without such level of concern elsewhere. Distribution's inadequate job of customer education should not be permitted to earn it a Commission waiver from a well-founded principle. Further, if Distribution had been applying the charge correctly, i.e., only charging it to full service customers, then the purpose of the itemization of this charge would have been more evident to its customers. It is supposed to be a part of their comparison between full service from the utility and commodity service from an ESCO. The whole reason the charge was unbundled in the first place and then unbundled on the bill in a separate and subsequent order was so that customers would be able to see “meaningful and useful information” on their bills that would be used in making decisions about their service. The wrong way that Distribution applied the charge contributed to the customer confusion they cite now in order to compound that wrong with yet another.

Also, apparently the RD was confused by the barrage of incorrect information provided by Distribution, for even under its proposal, some customers would not be subject to the billing charge. The company has ESCOs in its service territory that use ESCO consolidated bills where the ESCOs bill for both their own commodity and the utility delivery service. Even in Distribution’s service territory, these customers are not charged a utility billing charge. So customers now considering enrollment with these ESCOs would now lose “meaningful and useful information” on their bills. In fact, it is unclear from the RD whether the customers already enrolled with these ESCOs would lose their current benefit of not paying the billing charge since it is recommended to be rolled back into the customer charge that they do pay. If they are losing this benefit, then an additional waiver would be necessary. Further, loss of this benefit would allow Distribution to collect a billing charge from customers to whom it does not even issue a bill. Obviously, this third potential wrong does not ameliorate the other two wrongs.

The Commission has directed the utilities to bill customers for bills that contain only utility service; this requirement applies to both full service customers and customers who receive separate bills for delivery from the utility and commodity from an ESCO. Where the ESCO bills the customer for all services, the ESCO has the option on how to charge for billing, but the utility does not charge the customer for it at all. Where the utility issues a consolidated bill for its own delivery commodity from ESCOs, the Commission has determined that the ESCO should pay for the utility’s billing services as it would any other billing provider to which it might subcontract. In order that the customer not pay twice for billing and the utility not receive more than its billing costs, the Commission determined that the customer would not pay for billing where an ESCO’s charges appeared on the bill. Then, when the Commission unbundled the actual customer bill, it determined that since the customer would not pay this charge to the utility when taking service from an ESCO, this charge should be displayed on the customer's full service bill. Indeed, when discussing the unbundling of this charge on customers' bills, it said:

> Since the billing charge is for a competitive service and is not charged to retail access customers receiving consolidated bills, from either the utility or the ESCO, it should not be subsumed within delivery. Doing so would obscure an amount that might be saved when service from a competitor is obtained.[25]

Clearly, Distribution has applied the Commission's principle concerning who should pay the billing charge incorrectly, confusing customers as to why they needed the information. The company's education efforts also compounded this initial error by not even sufficiently educating customers that paying for their service on ESCO consolidated bills would mean that this amount would be saved. Now it seeks to confuse the issue by proposing to rectify the wrong with yet more incorrect application of Commission policy and orders.

Distribution should be ordered to apply the Commission's orders on billing, the billing charge, and the display of the billing charge on customers' bills correctly. To do otherwise would allow ESCOs to avail themselves of a free billing service from the company and provide a counter-incentive for ESCOs to do their own billing. It would make Distribution totally inconsistent with the other New York State utilities on this issue and be inconsistent with recent decisions of the Commission for these other utilities where billing charges were an issue. Depending on whether the RD intended that a different customer charge apply to customers with ESCO consolidated billing or not, there would also be created either a situation where customers were being charged by Distribution for a bill never issued (if the customer charge was intended to be the same for all customers) or where Distribution's bills "would obscure an amount that might be saved when service from a competitor is obtained" (if the RD intended that the customer charge for an ESCO consolidated bill customer would be reduced by applying a billing credit). To do so, moreover, would require waiver of at least two Commission orders. Accordingly, the RD's recommendation regarding the billing charge should be reversed by the Commission and the Staff's proposal for Distribution to comply with existing Commission orders should be affirmed.

[25] Case 00-M-0504 – Competitive Opportunities – Unbundling Track, Order Directing Submission of Unbundled Bill Formats (issued February 18, 2005), p. 23.

Merchant Function Charge and Annual Reconciliation of Its Components

The RD left certain issues concerning the merchant function charge (MFC) unresolved. Specifically, the RD does not resolve how the MFC is to be recovered, how much the MFC is to recover, and whether records and collection (R&C) cost recovery should be in the purchase of receivables (POR) discount rate. Further, it incorrectly resolves the issue of the annual reconciliation of MFC based on a phantom concession; one that staff did not and does not make and does not exist.

Net revenues, exclusive of taxes and commodity costs, are set at $262,278,000 (RD's Appendix 1, page 1 of 8). Revenues to recover the fixed costs for R&C on commodity costs should be $9,849,903 (3.7095% of net revenues, $7,966,079 residential, balance non-residential), for procurement (supply) of commodity should be $3,524,525 (1.3438% of net revenues, $3,293,196 residential, balance non-residential), and for R&C of POR program receivables should be $832,461 (0.3135% of net revenues, $538,171 residential, balance non-residential). A remainder of $248,071,111 in net revenues should be recovered through rate design.

In addition to the net revenues, additional revenues are projected to be collected for the variable costs related to uncollectibles of commodity costs and storage gas carrying charges. Based on projected commodity costs and monthly storage gas levels, the additional revenues will total $10,697,884 ($12,216,826 for uncollectibles less a credit of $1,518,942 for carrying charges on a negative storage gas balance which is due to Distribution's last-in-first-out (LIFO) accounting method).

Recovery of the MFC is to be accomplished by a volumetric rate. The components of the volumetric rate for the fixed costs for R&C and supply should be set once at the start of the rate year, with the amount collected reconciled to $9.850 Million and $3.525 Million from above, respectively, at the end of the rate year. The components of the volumetric components for the variable costs are to be set monthly based on the natural gas supply (NGS) charge for uncollectibles and the projected carrying costs on storage gas. The volumetric rate for uncollectibles should be 2.8276% of the NGS for residential service classifications and 0.4020% of the NGS for non-residential service classifications. The volumetric rate for the gas storage carrying charge may alternatively be set once at the start of the rate year; but, in either case, the amount collected or credited to customers is to be reconciled to the actual carrying costs at the end of the rate year.

The merchant function statement will contain the four components totaled to the one MFC to be shown on the NGS for both residential and non-residential classes. The residential and non-residential classes will have different MFCs as all, but the component for carry charges on storage gas, are different. Based on the RD, the MFC for residential customers and non-residential customers are projected to average $0.5050 per Mcf and $0.2479 per Mcf, respectively.

The company proposes that the MFC be a set percentage of the NGS each month. The NGS varies each month so the company's proposal will lead to substantial over collection in cold winters with higher gas usage and typically higher gas prices and substantial under collection in warm winters with lower gas usage and typically lower gas prices. The MFC is neither subject to weather normalization nor a revenue decoupling mechanism. It is critical, therefore, that an annual reconciliation of the MFC be performed. Absent reconciliation, it is possible that the company could over collect on the $13.4 Million in fixed costs, which both Staff and the company agree do not change significantly within a rate year. For example, a 10% colder winter with 40%t higher prices would result in a windfall of $7.2 Million for the company due to commodity prices. To summarize, if the RD's recommendation were adopted, then natural gas supply would become a profit center for the company without annual reconciliations.

The RD refers to a Staff concession allegedly in its reply brief on reconciliations of the MFC. Staff did not make such a concession and Staff can find no where in the record where such a concession was made. The company is entitled to a fair rate of return for its merchant function services, R&C and supply. An annual reconciliation assures that the company receives a return that is neither excessive nor deficient.

While it is true that the fixed costs in the MFC will change little in the rate year, costs are only half of the reconciliation equation. The other half is how much is collected. Without an annual reconciliation, the customer will underpay in warm weather with low gas prices and overpay in cold weather with high prices for the company's merchant function services, in direct proportion to the severity of the weather and gas pricing.

Staff has allocated R&C costs to POR by revenues consistent with the allocation of R&C costs by revenues between company delivery and commodity service in the unbundling of services. These costs should be included in the determination of the POR discount rate.

LOCAL GAS PRODUCTION

Orifice and Rotary Meters

The RD correctly identifies the crux of the issue concerning the installation of replacement rotary meters as who will bear the equipment and installation costs. RD at 86. However, the RD incorrectly identifies a lack of steady flow as the reason for the replacements, thereby leading to local producers paying the costs. RD at 84.

Local producers are responsible for the costs pursuant to the interconnection agreements if there is a change in their operations. There has been no change in operations since the interconnection agreements. Distribution's proposal identified 334 "low flow," not "intermittent flow" meters, and an additional 38 orifice meters for replacement. Tr. 435-436. The low flow situations did exist at the time the interconnection agreements were executed and there has been no change in the producer's operations since that time. Therefore, Distribution remains responsible for the costs.

Further, contrary to the RD's statement (at 84), the original costs of the rotary meters were not, in the first instance, paid for by the local producers and the meters have been included in rate base. Tr. 436. The inclusion of these costs in Distribution's capital budget is a continuation of existing policy.

The RD also misstates Staff's position on replacement costs. An annual budget of $100,000 over three years was envisioned by Staff for these replacements. This covered the meter cost of $750 per meter. Installation costs between $600 and $1,200 were never to be included. The separately identified $1,950 cost of a pressure and temperature corrector was developed very late in the proceeding by Distribution. This cost has not been audited and competitive bids for suitable alternatives are not known. However, the existing orifice meter correctors are in rate base and the proper rotary meter correctors should likewise be included; otherwise, the addition of these costs would be detrimental to local production gas supply.

Additionally, overall rate base exposure should range from $300,000 to a maximum of $900,000 depending on proper selection of a corrector, not the $1.3 Million indicated by the RD. RD at 84. Inclusion of this funding in rate base is beneficial to the ratepayers in general because any source of gas inside a distribution territory serves as a benefit to reliability.

Furthermore, subsequent to Staff's submission of its reply brief in this case, the Commission issued an order in Case 07-G-0299 in which it reiterated the importance of local production gas to distribution systems statewide as a direct replacement for LDC-provided capacity.[26] The RD position in support of Distribution's proposals is in direct contravention to this Commission order because it threatens the continuation of 46% or 2.7 BCF of annual local production gas flow. Tr. 435-36. The risk of losing this supply source to the distribution system market should not be tolerated. Transportation customers should not be forced to find alternative suppliers or require access to National Fuel Gas Supply Company and other upstream pipeline capacity.

CAPACITY MATTERS

Retained and Contingency Capacity

The RD states that "…each party should endeavor to provide a basic and simple explanation of the issue, the differences in the parties' respective positions, and the ultimate significance of treating the contingent capacity either like the reserve capacity or on the same basis as the firm, peak day consumption requirements." RD at 89-90.

"Retained (or Reserved) Capacity" is capacity held to provide the following services: monthly and daily burner-tip balancing, temperature swing service for monthly balanced customers, and operational balancing for local production deliveries. "Contingency Capacity" is capacity in excess of "Firm Design Day" consumption requirements. It is important to note that "Retained Capacity" is included in the "Firm Design Day" consumption requirements. Both Distribution and Staff agree that the approximately 30,000 dths per day level of excess capacity is valuable to be maintained. This capacity would be used for reliability protection in case of forecast inaccuracy, Provider of Last Resort (POLR) requirements, or potential third party provider failures.

The issue revolves around the differences on how to recover the costs of the "Contingency Capacity." Distribution proposes inclusion of all the contingency capacity costs in the calculation of Retained or Reserved Capacity. Staff agrees with including these costs in the "Reserve Capacity Costs Analysis" but on a pro-rata basis, only as appropriate to back up those services. Tr. 502-03.

The "Contingency Capacity" is used as protection for the full forecasted "Firm Design Day" consumption requirements. Tr. 503. A comparison of Exh. 45 (TJC-13, Sch. 1,

[26] Case 07-G-0299, Issues Associated With the Future of the Natural Gas Industry, Order On Capacity Release Programs (issued August 30, 2007).

p.1) and Exh. 42 (CP-3) indicates that the company's methodology would transfer approximately $1.3 Million of capacity costs to transportation customers for standby services they did not request. In addition, several transportation customers, despite maintaining firm transportation service on Distribution's system, are only guaranteed delivery of gas they deliver to the Distribution's city gate. A separate standby service tariff exists for these and all transportation customers, if they so need or desire. This is consistent with previous Commission orders regarding reliability and retention of capacity by all distribution companies.

However, the company would have us believe that the opposite is true. It argues that Staff's methodology shifts the $1.3 Million back into the Gas Cost Adjustment Recovery Mechanism and places an unfair burden on the captured sales customer. On the surface, while this might appear to be true, it is not. As stated above, previous Commission orders clearly define expectations of how gas distribution companies approach excess capacity. Utilities should ensure that adequate pipeline capacity exists to serve the needs of their firm delivery customers. However, long term gas supply and capacity contracts held by utilities are to be kept to the minimum level necessary to provide reliable service.[27]

The inclusion of the entire amount of "Contingency Capacity" into transportation customers balancing and swing service charges is not an appropriate mitigation method. This proposed action only serves to transfer the Distribution's responsibility for mitigation of these capacity costs to marketers and transportation customers. If a marketer or transportation customer is in need of gas supplies utilizing this capacity, then existing Distribution tariffs are already in-place to provide these services at a premium, exceeding actual costs. Inclusion as the company suggests would lead to a double billing of these costs and would indicate that non-core customers maintain a right to this capacity when previous Commission orders and existing policy states otherwise. Only inclusion of a pro-rata portion of "Contingency Capacity" into the "Reserved Capacity Costs Analysis," as proposed by Staff makes sense.

At a minimum, Distribution must demonstrate that it has made reasonable efforts to minimize strandable costs associated with excess capacity in compliance with the

[27] Case 00-M-0504, Statement of Policy on Further Steps Toward Competition in Retail Energy Markets (issued August 25, 2004), p. 22.

Commission's directives in Case 93-G-0932,[28] including the requirements of the Order Clarifying the April 1998 Excess Capacity Filing Requirements (issued September 4, 1997).

Capacity Releases, Off-System Sales and Storage Fill Arrangements

Staff disagrees with the RD position that this activity is at all similar with the incentives in place to recoup the costs of underutilized interstate pipeline capacity. The RD supports Distribution's proposal to include "storage fill" revenues in the customer/shareholder sharing mechanism incentive for capacity release and off-system sales. It states that this is due to the similarities in the management of the storage capacity entitlements with capacity releases and off-system sales, and the Distribution's efforts to optimize its revenues from all three sources. RD at 95. The RD ignores the fact that the Commission requires optimization of storage management by the company.

Storage fill arrangements involve the pricing of commodity gas purchased. The Commission's Gas Purchasing Policy states that an LDC faces a heavy burden of proof if it has not diversified its purchased gas portfolio. Storage gas is one of Distribution's primary sources of gas used to not only meet winter supply requirements, but to also serve as a physical hedge to mitigate volatility and, as such, is required under this policy. Distribution is responsible for and is required to provide the least cost reliable gas available. S-IB at 89.

The RD also ignores the fact that the existing capacity releases and off-systems sales incentives are in place to ensure that the costs of underutilized capacity, needed for reliability purposes, can be optimally minimized. These transactions both involve the release of excess or surplus pipeline capacity to ensure that captive sales customers will benefit more from the transactions than without them. Commission Opinion 94-26 at page 27, states:

> For revenues or credits received from the release of excess capacity and other pipeline services, staff recommended that LDCs be allowed to retain 15% of the net revenues or credits from such transactions and require them to pass along the other 85% to their customers.

The storage fill arrangements are not methods to minimize the costs of excess capacity or other pipeline services. These contracts are simply an outsourcing of Distribution's required purchasing function and should not qualify for incentive treatment.

---

[28] Cases 93-G-0932 and 97-G-1380, Policy Statement Concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment (issued November 3, 1998), p. 8.

Further, it is long-standing Commission policy that LDCs are not allowed to profit from their gas supply purchases. This point is made in a Staff Position Paper: "Some LDCs would like to exit the merchant function as soon as possible. These LDCs see the merchant function as something with no upside, because they are not allowed to earn any profit on their gas supply purchases but remain at risk (subject to prudence review) for those supply arrangements." [29] In support of this long-standing policy, 16 NYCRR, Section 720.6.5 (g) Annual Reconciliation state: "Actual gas cost recoveries shall be reconciled with actual gas expenses each year." There are no provisions for gas commodity profits to a distribution company.

Distribution itself recently acknowledged this concept in a press release: "Natural gas costs account for about 70 percent of a typical National Fuel customer's total bill… National Fuel does not make money on the gas portion of a customer's bill."[30] However, based on the RD, the last sentence would no longer be correct. The RD allows sharing of a perceived savings on storage fill arrangements, and will allow Distribution to earn a profit on the gas portion of the customer's bill. Such a recommendation would establish a risky and dangerous precedent and should not be adopted.

Capacity Cost True-Up Mechanism

The RD does not support Staff's proposed true-up mechanism. It considered the concerns identified by Distribution and Staff and recommended "further commitment of Company and Staff resources to determine whether another means can be used to account for capacity cost differences when the capacity is released to ESCOs." RD at 91-92.

The purpose of the true-up mechanism would be to account for the difference between the cost of the released capacity and the Distribution's weighted average cost of capacity. The intent of Staff's true-up proposal, in situations where it is impractical for a company to assign capacity to ESCOs based on the FERC "slice of the system" approach, is to align capacity costs with end-use to avoid potential customer cross-subsidization. Such mechanisms have been implemented by most of the downstate companies, some of which

---

29 Case 97-G-1380, The Future of the Natural Gas Industry, Staff Position Paper (issued September 4, 1997), pp.10-11

30 The Buffalo News, "National Fuel Warns of Higher Heating Bills" by David Robinson, Wednesday, October 10, 2007.

experience issues similar to Distribution. Each company has developed a mechanism to true-up these costs reflective of its individual circumstances.

In the order in Case 07-G-0299 mentioned above, the Commission stated (at. 13): "Obtaining cost parity is a reasonable goal where LDC's are not able to implement the actual releases in a pro-rata share of its system. In those cases, a customer credit/surcharge mechanism may be used to ensure that the costs to the utility and marketer customers are comparable." Staff supports the RD's position to continue discussions with the company on this matter, and believes discussions should result from Distribution's compliance filings made pursuant to the August 30th Commission Order.

MISCELLANEOUS MATTERS

Service Classes Subject to the 90%/10% Sharing Mechanism

The RD indicated that this issue briefed by MI has not been joined by other parties and, therefore, could not be decided in their favor. RD at 98-99. It should be noted that MI offered no direct testimony supporting its position on this issue and thereby avoided any opportunity for the parties to probe the assertions in MI's brief through cross examination. Staff, and every other party except MI, did not oppose the company's proposal because it represented appropriate rate making treatment for a sales forecast reconciliation that affects the delivery revenue requirement to all customer classes.

As MI indicates in its initial brief, the 90/10 sharing mechanism has been in existence since 1986. MI-IB at 77. As background, the 90/10 sharing mechanism was created primarily because of the difficulties associated with forecasting the sales to then existing Distribution service classes with customers, primarily large industrial and boiler fuel users, whose natural gas usage was strongly influenced by market conditions and the price of alternate fuels. The Commission adopted the existing mechanism in an effort to ensure that all customers' tariff rates ultimately reflected a revenue requirement based on a sales forecast reflective of actual sales levels. For ratemaking purposes, the Commission approved a level of margin from these sales, which was imputed in the revenue requirement, and subsequently reconciled to the actual sales margin level experienced. In practice, the Commission generally adopted an imputed margin level that reflected actual historic sales levels, adjusted for expected changes, in order to limit the impacts of the resulting surcharges or refunds. In addition, as an incentive for Distribution to both increase incremental margin from sales to these classes, which ultimately serves to reduce the revenue requirement and therefore benefits all customers, and maintain current sales levels, the Commission adopted a sharing mechanism.

The mechanism allowed the Distribution to retain 10% of any incremental sales margin above the imputed level, but limited the recovery of reduced sales margin below the imputed level to only 90%. The gas adjustment clause (GAC) was initially established as the ratemaking vehicle for the resulting surcharge or refund because all of Distribution's customers at the time were using firm bundled sales service, and, therefore, it was the appropriate choice to reconcile the results of the mechanism to all customers. However, now most of the service classes subject to the 90/10 mechanism have become predominantly transportation customers who do not pay the GAC, and therefore, have become insulated from the benefits, or consequences, of the included 90/10 mechanism. The company's proposal would finally recognize this change in circumstance and revise the operation of the 90/10 mechanism to reconcile the results of the mechanism to all firm customers, sales and transportation, as was originally intended by the Commission.

MI, on the other hand, argues that returning the mechanism to apply to transportation customers will result in additional surcharges being imposed on the most price sensitive customers. MI-IB at 79. It cites the fact that the results of the mechanism in recent years produced overall surcharges. MI-IB at fn. 92. As we explained above, surcharges result when the sales margin imputed is not achieved. Failure to achieve the imputed margin level can be caused by only two things: 1) a reduced margin rate; or 2) an overly optimistic imputed sales forecast. In Distribution's case, since the delivery rates for service classes subject to the mechanism are fixed tariff rates, the recent failure to achieve the imputed level can, accordingly, only be attributed to an overly optimistic imputed sale forecast level.

Ironically, although MI represents many customers in service classes included in the 90/10 mechanism and, therefore, must be aware of the potential usage of these customers, it chose not to propose any downward adjustment to the company's proposed 90/10 imputed target in recognition of the recent years' experience. To the contrary, MI acknowledges that the company's proposal increased the current target by approximately 7.4%, (MI-IB at 77), but proposes no reduction in forecast in order to ameliorate what could potentially be another overly optimistic margin imputation and potentially result in another surcharge.

MI recognizes that the adoption of an overly optimistic 90/10 imputation serves to reduce the overall revenue requirement, which ultimately reduces the delivery rates to its represented customer classes. MI also knows that if it is able to maintain the existing 90/10 provisions, then those represented customers will avoid the consequences of that overly optimistic imputation; a subsequent surcharge. MI is thus more than content to require all the other rate payers to pick up this tab after its own customers' delivery rates are fixed by the Commission. This "heads I win, tails you lose" position is not only inconsistent with the original intent of the 90/10 sharing mechanism, but also it is plainly unreasonable and improper rate making, since it results in an inappropriate and hidden revenue re-allocation away from the customers represented by MI.

In addition, MI attempts to cite examples of similar sharing mechanisms in place at Orange & Rockland Utilities and National Grid where the results of the mechanism do not apply to transportation customers. MI-IB at 78. First, both of these mechanisms are distinguishable from the Distribution mechanism in that each applies to interruptible service classes which are flexibly priced based on the cost of alternate fuels. As we noted previously, the service classes included in the Distribution 90/10 mechanism are all firm service classes with <u>fixed tariff rates</u>. Where sharing mechanisms have been established for flexibly priced interruptible service classes, it has been unrealistic to include those same interruptible classes in the reconciliation because the application of a surcharge or refund would not be possible since the price for interruptible service could not incorporate a surcharge or refund and still maintain the market based relationship with the applicable price for alternate fuels. The surcharge or refund would be effectively lost. Consequently, on this basis the MI comparison of the NFG 90/10 mechanism to these other sharing mechanisms is "apples to oranges."

Second, MI is totally incorrect on the service classifications subject to the results of the sharing mechanism approved by the Commission for Orange & Rockland.[31] By tariff, the results of the Orange & Rockland sharing mechanism are passed through the Monthly Gas Adjustment (MGA) which is applicable to both sales and transportation services.[32] Therefore, the change in treatment proposed by NFG for the 90/10 mechanism in this case is absolutely consistent with the provisions of the Orange & Rockland sharing mechanism.

[31] MI also acknowledges that the results of the National Grid mechanism are also applicable to both sales and transportation service classes (MI-IB at 78).

[32] Case 05-G-1494, Order Establishing Rates and Terms of Three-Year Rate Plan issued and effective October 20, 2006, Joint Proposal at p. 21. The provisions of the Monthly Gas Adjustment are also defined in the Orange & Rockland Utilities Tariff, P.S.C. No. 4 Gas, Leaf 80, Rule 12.2 Monthly Gas Adjustment.

Accordingly, the revision to the 90/10 sharing mechanism proposed by Distribution is proper rate making treatment, which was not opposed by Staff or any other party and, accordingly, should be adopted by the Commission.

UPDATES

Cost of Capital

The following are the updated cost of capital rates for Distribution for the rate year ending December 31, 2007:

Long Term Debt Rate – The long term debt rate remains unchanged at 6.57%.

Short Term Debt Rate – This rate was updated on the basis of Staff's methodology, the average A2/P2 commercial paper rates for the month of September 2007. The updated short term debt rate is 5.69%.
Customer Deposits Rate – The updated customer deposits debt rate is 3.76% (effective January 1, 2008).
Allowed Return on Equity – Using Staff's proxy group and methodology, the update in treasury rates as of September 30, 2007, resulted in a 10 bps increase in the allowed return on equity from 9.10% to 9.20%.

GDP Inflator

The updated GDP deflator rate is 5.60%.

SIT

The updated SIT rate is 7.1%.

Health Care Costs

Staff has updated the inflation factor applied against hospitalization expense, and the higher inflation forecast increases Hospitalization Expense by $18,000. This item is not included in the inflation pool because it is a stand-alone item.

CONCLUSION

For the reasons expressed above, Staff respectfully urges the Commission to adopt Staff's exceptions to the RD and to institute a proceeding to investigate allocation issues pertinent to National's corporate structure.

Respectfully submitted,

RUTH A. AMES
Legal Intern
518-474-6522

JOHN L. FAVREAU
Assistant Counsel
518-474-1573

SAUL A. RIGBERG
Assistant Counsel
518-486-2652

Dated: October 17, 2007
Albany, New York

APPENDICES

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Affiliate Rules

1.0 Affiliate Relations – In General

1.1 National Fuel Gas Distribution Company ("NFGD") and National Fuel Gas Company's ("NFG")[1] other subsidiaries will be operated as separate entities.

1.2 Any transfer of assets or the provision of goods or services, other than tariffed services and corporate governance, administrative, legal and accounting services by NFGD to an unregulated subsidiary or an unregulated subsidiary to NFGD, will be pursuant to regulations of the Securities Exchange Commission ("SEC") and the Public Service Commission of New York ("PSC").

1.3 Cost allocation guidelines if amended and/or supplemented will be filed with the Director of the Office of Accounting and Finance of the Department of Public Service 30 days prior to becoming effective.

1.4 All cost allocations will be subject to review during rate proceedings.

2.0 Non-Discriminatory Application of Tariffed Services

2.1 NFGD shall apply its tariffs in a nondiscriminatory manner.

2.2 NFGD shall not apply a tariff provision in any manner that would give its affiliates an unreasonable preference over other parties with regard to matters such as scheduling, balancing, transportation, storage, curtailment, capacity release and assignment, or non-delivery, and all other services provided to its affiliates.

2.3 Tariff provisions cannot be waived by NFGD absent prior approval of the PSC.

---

[1] NFG holding company is registered as a holding company under the Public Utility Holding Company Act of 193 5.

2.4 If a tariff provision is not mandatory or permits discretionary waivers, NFGD shall grant the waivers without preference to its affiliates. NFGD shall apply the provisions of its Gas Transportation Operating Procedures Manual without preference to its affiliates.

2.5 NFGD shall process requests for distribution services promptly and in a nondiscriminatory fashion with respect to other requests received in the same or a similar period.

2.6 If NFGD provides a distribution service discount, fee waiver or rebate to customers of its affiliated marketer, NFGD shall offer the same distribution service discount, fee waiver or rebate to other similarly situated parties. Offers shall not be tied to any unrelated service, incentive or offer on behalf of either the natural gas distribution company or its affiliates.

3.0 Personnel

3.1 Unregulated affiliates will have separate operating employees.

3.2 Non-administrative operating officers of NFGD will not be operating officers of any of the unregulated subsidiaries.

3.3 Officers of NFG may be officers of NFGD.

3.4 Employees may be transferred between NFGD and an unregulated affiliate upon mutual agreement. Employees transferred to a marketing affiliate may not be reemployed by NFGD for a minimum of 12 months from the transfer date. Employees returning to NFGD from a marketing affiliate may not be transferred to a marketing affiliate for a minimum of 24 months from the date of return or in the case of a transfer to an unregulated affiliate, for a minimum of 12 months. The foregoing limitations will not apply to employees covered by a collective bargaining agreement.

3.5 NFGD will not restrict by any means the employment with marketers of employees of NFGD unless NFGD applies the same restriction to its affiliated marketer(s). NFGD may negotiate restrictive employment conditions in severance agreements with employees under which the employee, as a result of a bargained-for exchange, receives value.

3.6 The foregoing provision in no way restricts the loaning of employees from any affiliate to NFGD to respond to an emergency that threatens the safety or reliability of service to consumers. Nor does the foregoing provision restrict the "loaned and borrowed labor" arrangement traditionally maintained between NFGD and National Fuel Gas Supply Corporation (**"NFGS"**) for routine system operational purposes.

3.7 The compensation of NFGD employees may not be tied to the performance of any of **NFG's** unregulated subsidiaries. However, the stock of NFG may be used as an element of compensation and the compensation of common **officers** of NFG and NFGD may be based upon the operations of NFG and NFGD.

3.8 The employees of NFG, NFGD, NFGS and the unregulated **affiliates** may participate in common pension and benefit plans.

4.0 Goods, Services and Transactions Between NFGD and Affiliates

4.1 NFGD shall justly and reasonably allocate to its affiliates the costs or expenses for general administration or support services provided to said entities.

4.2 NFGD shall not condition or tie the provision of any product, service or price agreement by it (including release of interstate pipeline capacity) to the provision of any product or service by its **affiliates.**

4.3 NFGD shall not give its **affiliates** preference over **non-affiliated** marketers in the provision of goods and services including processing requests for information, complaints and responses to service interruptions. NFGD shall provide comparable treatment in its provision of such goods and services without regard to a customer's chosen marketer.

4.4 NFGD and **affiliated** marketers shall not be located in the same building or share office structures or centralized computer and/or communication networks. The NFG Corporate **Website** and corporate-governance transactions (such as those performed for financial reporting purposes) are exempt from the restriction pertaining to joint use of centralized computer and/or communications network.

4.5 NFGD shall maintain separate books and records from its affiliates. Further transactions between NFGD and its affiliates shall not involve cross-subsidies. Any shared facilities shall be fully and transparently allocated between the distribution company and affiliates. NFGD's accounts and records shall be maintained such that the costs incurred on behalf of an affiliate may be clearly identified.

4.6 NFGD may provide other services to affiliates, except that NFGD may not use any of its marketing or sales employees to provide services to NFGS or an affiliated marketer. NFGS and the affiliated marketers shall compensate NFGD for the services of employees performing such services in accordance with the orders, rules and regulations of the SEC governing same.

4.7 NFGD's affiliates, including NFGS and any affiliated marketers may provide services to NFGD. subject to any applicable requirements of this PSC, the SEC and the Federal Energy Regulatory Commission.

4.8 Common propertyicasualty and other business insurance policies may cover NFG, NFGD, NFGS, and other affiliates. The costs of such policies shall be allocated among the entities in an equitable manner.

4.9 Notwithstanding the above, the Commission's Order on Rehearing in Case 98-G-0122 – Proceeding on Motion of the Commission to Review the Bypass Policy Relating to Pricing of Gas for Electric Generation dated June 29, 2001, and any additional review of that order, continues to control the issues resolved there.

5.0 Customer Information

5.1 Release of proprietary customer information relating to customers within NFGD's service territory shall be subject to the Uniform Business Practices ("UBPs") and. if required. prior authorization by the customer and subject to the customer's direction regarding the person(s) to whom the information may be released. If a customer authorizes the release of information to an affiliate and one or more of the affiliate's competitors, NFGD shall make that information available to the affiliate and such competitors on an equal and contemporaneous basis.

5.2 NFGD will not disclose to marketing or pipeline affiliates any customer or marketer information that it receives from a marketer, non-affiliated pipeline or gatherer, customer, or potential customer, which is not available from sources other than NFGD. Excluded from this restriction is operational information supplied to a pipeline affiliate necessary to implement changes in system operations.

5.3 Subject to customer privacy or confidentiality constraints, NFGD shall not disclose, directly or indirectly, any customer proprietary information to its affiliate unless authorized by the customer or the UBPs.

6.0 Customer Communications

6.1 NFGD shall not directly or by implication, represent to any customer, natural gas supplier or third party that an advantage may accrue to any party through use of NFGD's affiliates, such as:

a. That the PSC regulated services provided by NFGD are of a superior quality when such services are purchased from its affiliated marketer; or

b. That the commodity services (for natural gas) are being provided by NFGD when they are in fact being provided by an affiliated marketer;

c. That the natural gas purchased from a non-affiliated marketer may not be reliably delivered;

d. That natural gas must be purchased from an affiliated marketer in order to receive the PSC regulated services.

6.2 On a one-time basis NFGD shall disclose to all of its affiliated marketer's customers the distinction between the LDC and its marketing affiliate. NFGD will disclose the same information to new customers of its marketing affiliate in the anti-slamming letter required by the UBPs. Proposed disclosure language shall be distributed to the marketer signatories to this agreement and shall be subject to their approval.

7.0 Standards of Competitive Conduct

The following standards of competitive conduct shall govern NFGD's relationship with any energy supply and energy service affiliates:

7.1 There are no restrictions on affiliates using the same name, trade names, trademarks, service name, service mark or a derivative of a name, of NFG or NFGD, or in identifying itself as being affiliated with NFG or NFGD. However, NFGD will not provide sales leads for customers in its service territory to any affiliate and will refrain from giving any appearance that NFGD speaks on behalf of an affiliate or that an affiliate speaks on behalf of NFGD. If a customer requests information about securing any service or product offered within the service territory by an affiliate, NFGD may provide a list of all companies known to NFGD operating in the service territory who provide the service or product, which may include an affiliate, but NFGD will not promote its affiliate.

7.2 NFGD will not represent to any entity that an advantage may accrue to anyone in the use of NFGD's services as a result of that customer, supplier or third party dealing with any affiliate. This standard does not prohibit two or more of the unregulated subsidiaries from lawfully packaging their services.

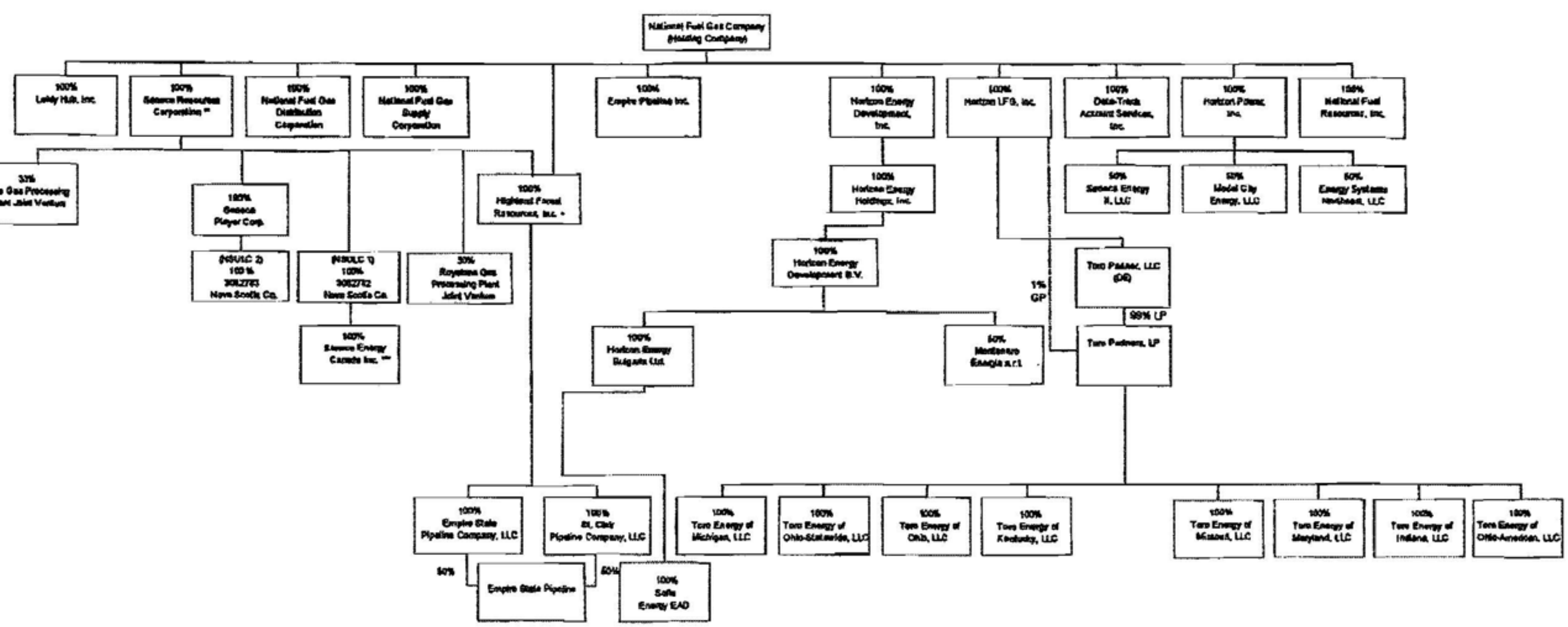
7.3 All similarly situated customers, including but not limited to energy services companies and customers of energy service companies, whether affiliated or unaffiliated, will pay the same rates for NFGD's utility services. NFGD shall apply any tariff provision in the same manner if there is discretion in the application of the provision.

8.0 Enforcement of Standards

8.1 If any competitor or customer of NFGD believes that NFGD has violated the standards of conduct established in this section of the agreement, such competitor or customer may file a complaint in writing with NFGD. NFGD will respond to the complaint in writing within 20 business days after receipt of the complaint. Within 15 business days after the filing of such response, NFGD and the complaining party will meet in an attempt to resolve the matter informally. If NFGD and the complaining party are not able to resolve the matter informally, the matter will be subject to the Dispute Resolution Procedures in accordance with the UBPs.

8.2 Nothing in this section prevents the PSC from taking action to enforce its statutory obligations.

National Fuel Gas Company
Organizational Chart of
Holding Company System
As of October 18, 2006



NFG owns 351 shares of Class A voting stock of Highland Forest Resources, Inc.
Seneca Resources Corporation owns 649 shares of Class B non-voting stock of
Highland Forest Resources, Inc.

Seneca is a general or limited partner of the following limited partnerships:

45.0
44.8
44.6
44.4
44.2

NFG

Press Release

Source: National Fuel Gas Company

Seneca Resources Signs Purchase and Sale Agreement for Canadian Properties

Tuesday August 7, 4:42 pm ET

WILLIAMSVILLE, N.Y.--(BUSINESS WIRE)--National Fuel Gas Company (NYSE: NFG - News; the "Company") today announced that its Exploration and Production unit, Seneca Resources Corporation ("Seneca") has signed a purchase and sale agreement to sell its subsidiary, Seneca Energy Canada Inc. ("SECI") to NAL Oil & Gas Trust for approximately U.S.$234.3 million (at a conversion of $1.05 Canadian to $1.00 U.S.). The sale has an effective date of July 1, 2007, and is expected to close by September 30, 2007.*

The sale is expected to result in a non-recurring gain of approximately $120 million, after tax, which will be reported in the Company's fourth quarter, which closes on September 30, 2007.*

In April, Seneca announced that it had retained a financial advisor to assist in the sale of this subsidiary and its associated properties in the western provinces of Canada. After reviewing several competitive bids, NAL Oil & Gas Trust's bid was accepted.

"We are pleased to have completed this transaction. After determining that the SECI properties were no longer a strategic fit for Seneca's operations, the next task was to divest those holdings in a fashion that would protect shareholder value. We believe that this sale accomplishes that goal and look forward to focusing on Seneca's properties in the Gulf of Mexico, Appalachia and California in order to maximize their potential for growth and development," said Philip C. Ackerman, Chairman and Chief Executive Officer, National Fuel Gas Company.

National Fuel is an integrated energy company with $3.8 billion in assets comprised of the following five operating segments: Utility, Pipeline and Storage, Exploration and Production, Energy Marketing, and Timber. Additional information about National Fuel is available on its Internet Web site: nationalfuelgas.com or through its investor information service at 1-800-334-2188.

* Certain statements contained herein, including those which are designated with an asterisk ("*") and those which use words such as "anticipates," "estimates," "expects," "intends," "plans," "predicts," "projects," and similar expressions, are "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The Company's expectations, beliefs and projections contained herein are expressed in good faith and are believed to have a reasonable basis, but there can be no assurance that such expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors, the following are important factors that could cause actual results to differ materially from those discussed in the forward-looking statements: changes in economic conditions, including economic disruptions caused by terrorist activities, acts of war or major accidents; physical damage or alteration to the assets of SECI that would have a material adverse effect on the aggregate value of those assets; significant closing adjustments to the

Quicklinks

Back to Company Detail page | New Search
Form 5500 | Schedule A | Schedule B | Schedule C | Schedule D | Schedule H | Schedule P |
Schedule R | Schedule T | Other Documents | SHOW ALL

SCHEDULE B (Form 5500)
Department of the Treasury
Internal Revenue Service

Department of Labor
Pension and Welfare Benefits Administration

Pension Benefit Guaranty Corporation

Actuarial Information

This schedule is required to be filed under section 104 of the Employee Retirement Income Security Act of 1974, referred to aas ERISA, except when attached to Form 5500-EZ and, in all cases, under section 6059(a) of the Internal Revenue Code, referred to as the Code.

Attach to Form 5500 or 5500-EZ if applicable.
See separate instructions.

Official Use Only
OMB No. 1210-0110

2004

This Form is Open to Public Inspection (except when attached to Form 5500-EZ)

For the calendar plan year 2004 or fiscal plan year beginning July 01, 2004, **and ending** June 30, 2005

If an item does not apply, enter "N/A." Round off amounts to nearest dollar.
Caution: A penalty of $1,000 will be assessed for late filing of this report unless reasonable cause is established.

A Name of plan
NATIONAL FUEL GAS COMPANY RETIREMENT PLAN

B Three digit plan number 001

C Plan sponsor's name as shown on line 2a of Form 5500 or 5500-EZ
NATIONAL FUEL GAS COMPANY

D Employer Identification Number
13-1086010

E Type of Plan: (1) ☐ Single-employer (2) ☒ Multiemployer (3) ☐ Multiple-employer

F ☐ 100 or fewer participants in prior plan year

Part I Basic Information (To be completed by all plans)

1a Enter the actuarial valuation date: July 01, 2004

b Assets

(1) Current value of assets	**b(1)**	$606,710,568
(2) Actuarial value of assets for funding standard account	**b(2)**	$620,111,496
c (1) Accrued liability for plans using immediate gain methods	**c(1)**	$559,979,340
(2) Information for plans using spread gain methods:		
(a) Unfunded liability for methods with bases	**c(2)(a)**	
(b) Accrued liability under entry age normal method	**c(2)(b)**	
(c) Normal cost under entry age normal method	**c(2)(c)**	

Statement by Enrolled Actuary (see instructions before signing):
To the best of my knowledge, the information supplied in this schedule and on the accompanying schedules, statements and attachments, if any, is complete and accurate, and in my opinion each assumption used in combination, represents my best estimate of anticipated experience under the plan. Furthermore, in the case of a plan other than a multiemployer plan, each assumption used (a) is reasonable (taking into account the experience of the plan and reasonable expectations) or (b) would, in the aggregate, result in a total contribution equivalent to that which would be determined if each such assumption were reasonable; in the case of a multiemployer plan, the assumptions used, in the aggregate, are reasonable (taking into account the experience of the plan and reasonable expectations).

Signature of actuary — Date

KATHLEEN P. LAMB — **G** 0503188

Print or type name of actuary — Most recent enrollment number

MERCER HUMAN RESOURCE CONSULTING — 585-325-2870

Firm Name — Telephone number (including area code)

720 BAUSCH & LOMB PLACE
ROCHESTER, NY 14604-2707

Address of the Firm

If the actuary has not fully reflected any regulation or ruling promulgated under the statute in completing this schedule, check the box and see instructions ☐

1d Information on current liabilities of the plan:

(1) Amount excluded from current liability attributable to pre-participation service (see instructions)	**d(1)**	
(2) "RPA '94" information:		
(a) Current liability	**d(2)(a)**	$608,361,598
(b) Expected increase in current liability due to benefits accruing during the plan year	**d(2)(b)**	$17,689,896

(c) Current liability computed at highest allowable interest rate (see instructions)	d(2)(c)	$608,361,598
(d) Expected release from "RPA '94" current liability for the plan year	d(2)(d)	
(3) "OBRA '87" information:		
(a) Current liability	d(3)(a)	
(b) Expected increase in current liability due to benefits accruing during the plan year	d(3)(b)	
(c) Expected release from "OBRA '87" current liability for the plan year	d(3)(c)	
(4) Expected plan disbursements for the plan year	d(4)	$40,960,753

2 Operational information as of beginning of this plan year:

a Current value of the assets (see instructions) **2a** $606,710,568

b "RPA '94" current liability:

	(1) No. of Persons	(2) Vested Benefits	(3) Total benefits
(1) For retired participants and beneficiaries receiving payments	2,402	$348,499,225	$348,499,225
(2) For terminated vested participants	286	$8,992,133	$8,992,133
(3) For active participants	1,869	$201,063,673	$250,870,240
(4) Total	4,557	$558,555,031	$608,361,598

c If the percentage resulting from dividing line 2a by line 2b(4), column (3), is less than 70%, enter such percentage **2c** %

3 Contributions made to the plan for the plan year by employer(s) and employees:

(a) Mo.-Day-Year	(b) Amount paid by employer	(c) Amount paid by employees	(a) Mo.-Day-Year	(b) Amount paid by employer	(c) Amount paid by employees
06/17/2005	$7,696,944				
12/22/2005	$1,800,000				
01/30/2006	$3,695,988				
02/22/2006	$6,807,068				

3 Totals (b) $20,000,000 **(c)**

4 Quarterly contributions and liquidity shortfall(s):

a Plans other than multiemployer plans, enter funded current liability percentage for preceding year (see instructions) **4a** 93.3%

b If line 4a is less than 100%, see instructions, and complete the following table as applicable:

	Liquidity shortfall as of end of Quarter of this plan year		
(1) 1st	(2) 2nd	(3) 3rd	(4) 4th

5 Actuarial cost method used as the basis for this plan year's funding standard account computation:

a ☐ Attained age normal **b** ☐ Entry age normal **c** ☒ Accrued benefit (unit credit)
d ☐ Aggregate **e** ☐ Frozen initial liability **f** ☐ Individual level premium
g ☐ Individual aggregate **h** ☐ Other (specify)

i Has a change been made in funding method for this plan year? ☐ Yes ☒ No

j If line i is "Yes," was the chage made pursuant to Revenue Procedure 95-51 as modified by Revenue Procedure 98-10? ☐ Yes ☐ No

k If line i is "Yes," and line j is "No" enter the date of the ruling letter (individual or class) approving the change in funding method

6 Checklist of certain actuarial assumptions:

a Interest rates for:

(1) "RPA '94" current liability	a(1)	6.32%	☐ N/A
(2) "ORBA '87" current liability	a(2)	%	☐ N/A
b Weighted average retirement age	6b	60	☐ N/A

		Pre-Retirement	Post-Retirement	
c Rates specified in insurance or annuity contracts ☐ N/A	6c	☐ Yes ☒ No	☐ Yes ☒ No	☐ N/A
d Mortality table code for valuation purposes:				
(1) Males	d(1)	9	9	
(2) Females	d(2)	9	9	
e Valuation liability interest rate ☐ N/A	6e	8.25%	8.25%	☐ N/A
f Expense loading ☐ N/A	6f	4.5%	%	☒ N/A
		Male	Female	
g Annual withdrawal rates:				
(1) Age 25	g(1)	8.00%	8.00%	
(2) Age 40	g(2)	8.00%	8.00%	
(3) Age 55	g(3)	8.00%	8.00%	
h Salary Scale ☐ N/A	6h	6.11%	6.11%	☐ N/A
i Estimated investment return on actuarial value of assets for the year ending on the valuation date	6i	2.0%		

7 New amortization bases established in the current plan year:

(1) Type of Base (2) Initial Balance (3) Amortization Charge/Credit

8 Miscellaneous information:

a If a waiver of a funding deficiency or an extension of an amortization period has been approved for this plan year, enter the date of the ruling letter granting the approval

b If one or more alternative methods or rules (as listed in the instructions) were used for this planyear, enter the appropriate code in accordance with the instructions

c Is the plan required to provide a Schedule of Active Participant Data? If "Yes," attach schedule. (see instructions) ☒ Yes ☐ No

9 Funding standard account statement for this plan year:
Charges to funding standard account:

a	Prior year funding deficiency, if any		9(a)	
b	Employer's normal cost for plan year as of valuation date		9(b)	$9,518,562
c	Amortization charges as of valuation date:	Outstanding Balance		
	(1) All bases except funding waivers	($)	c(1)	
	(2) Funding waivers	($)	c(2)	
d	Interest as applicable on lines 9a, 9b, and 9c		9d	$785,281
e	Additional interest charge due to late quarterly contributions, if applicable		9e	
f	Additional funding charge from Part II, line 12u, if applicable ☐ N/A		9f	0
g	Total charges. Add lines 9a through 9f		9g	$10,303,843
	Credits to funding standard account:			
h	Prior year credit balance, if any		9h	$163,820,621
i	Employer contributions. Total from column (b) of line 3		9i	$20,000,000
		Outstanding Balance		
j	Amortization credits as of valuation date	($)	9j	
k	Interest as applicable to end of plan year on lines 9h, 9i, 9j		9k	$13,536,963
l	Full funding limitation (FFL) and credits			
	(1) ERISA FFL (accrued liability FFL)	l(1) $153,180,031		
	(2) "OBRA '87" FFL (155% current liability FFL)	l(2)		
	(3) "RPA '94" override (90% current liability FFL)	l(3)		
	(4) FFL credit before reflecting "OBRA '87" FFL		l(4)	
	(5) Additional credit due to "OBRA '87" FFL		l(5)	
m	(1) Waived funding deficiency		m(1)	
	(2) Other credits		m(2)	
n	Total credits. Add lines 9h through 9k, 9l(4), 9l(5), 9m(1), and 9m(2)		9n	$197,357,584
o	Credit balance: If line 9n is greater than line 9g, enter the difference		9o	$187,053,741
p	Funding deficiency: If line 9g is greater than line 9n, enter the difference		9p	
	Reconciliation account:			
q	Current year's accumulated reconciliation account:			
	(1) Due to additional funding charges as of the beginning of the plan	q(1)		
	(2) Due to additional interest charges as of the beginning of the plan year	q(1)		
	(3) Due to waived funding deficiencies:			
	(a) Reconciliation outstanding balance as of valuation date	q(1)		
	(b) Reconciliation amount. Line 9c(2) balance minus line 9q(3)(a)	q(1)		
	(4) Total as of valuation date		q(4)	

10 Contribution necessary to avoid an accumulated funding deficiency. Enter the amount in line 9p or the amount required under the alternative funding standard account if applicable — 10

11 Has a change been made in the actuarial assumptions for the current plan year? If "Yes," see instructions ☒ Yes ☐ No

Part II Additional Information for Certain Plans Other Than Multiemployer Plans

12 Additional required funding charge (see instructions):

a Enter "Gateway %." Divide line 1b(2) by line 1d(2)(c) and multiply by 100.
If line 12a is at least 90%, go to line 12u and enter -0-.
If line 12a is less than 80%, go to line 12b.

If line 12a is at least 80% (but less than 90%), see instructions and, if applicable, go to — 12a 101.9%

	line 12u and enter -0-. Otherwise, go to line 12b			
b	"RPA'94" current liability. Enter line 1d(2)(a)			**12b**
c	Adjusted value of assets (see instructions)			**12c**
d	Funded current liability percentage. Divide line 12c by 12b and multiply by 100			**12d** %
e	Unfunded current liability. Subtract line 12c from line 12b			**12e**
f	Liability attributable to any unpredictable contingent event benefit			**12f**
g	Outstanding balance of unfunded old liability			**12g**
h	Unfunded new liability. Subtract the total of lines 12f and 12g from line 12e. Enter -0- if negative.			**12h**
i	Unfunded new liability amount (% of line 12h)			**12i**
j	Unfunded old liability amount			**12j**
k	Deficit reduction contribution. Add lines 12i, 12j, and 1d(2)(b)			**12k**
l	Net charges in funding standard account used to offset the deficit reduction contribution. Enter a negative number if less than zero			**12l**
m	Unpredictable contingent event amount:			**12m**
	(1) Benefits paid during year attributable to unpredictable contingent event	**m(1)**	0	
	(2) Unfunded current liability percentage. Subtract the percentage on line 12d from 100%	**m(2)**		
	(3) Enter the product of lines 12m(1), 12m(2), and 12m(3)	**m(4)**		
	(4) Amortization of all unpredictable contingent event liabilities	**m(5)**		
	(5)"RPA '94" additional amount (see instructions)	**m(6)**		
	(6)Enter the greatest of lines 12m(3), 12m(4), or 12m(5)			**m(7)**
	Preliminary Calculation			
n	Preliminary additional funding charge: Enter the excess of line 12k over line 12l (if any), plus line 12m(6), adjusted to end of year with interest			**12n**
o	Contributions needed to increase current liability percentage to 100% (see instructions)			**12o**
p	Additional funding charge prior to adjustment: Enter the lesser of line 12n or 12o			**12t**
q	Adjusted additional funding charge. (% of line 12p)			**12u**

Back to Top

8 Experience related contracts
a Premiums:
(1) Amount received
(2) Increase (decrease) in amount due but unpaid
(3) Increase (decrease) in unearned premium reserve
(4) Earned ((1)+(2)-(3))
b Benefit charges:
(1) Claims paid
(2) Increase (decrease) in claim reserves
(3) Incurred claims (add (1) and (2))
(4) Claims charged
c Remainder of premium:
(1) Retention charges (on an accrual basis) –
(A) Commissions
(B) Administrative service or other fees
(C) Other specific acquisition costs
(D) Other expenses
(E) Taxes
(F) Charges for risks or other contingencies
(G) Other retention charges
(H) Total Retention
(2) Dividends or retroactive rate refunds. (These amounts were ☐ paid in cash, or ☐ credited.)
d Status of policyholder reserves at end of year: (1) Amount held to provide benefits after retirement
(2) Claim reserves
(3) Other reserves
e Dividends or retroactive rate refunds due. (Do not include amount entered in c(2).)
9 Nonexperience-rated contracts
a Total premiums or subscription charges paid to carrier
b If the carrier, service, or other organization incurred any specific costs in connection with the acquisition or retention of the contract or policy, other than reported in Part I, item 2 above, report amount
Specify nature of costs below:

SCHEDULE B (Form 5500)
Department of the Treasury
Internal Revenue Service

Department of Labor
Pension and Welfare
Benefits Administration

Pension Benefit
Guaranty Corporation

Actuarial Information

This schedule is required to be filed under section 104 of the Employee Retirement Income Security Act of 1974, referred to aas ERISA, except when attached to Form 5500-EZ and, in all cases, under section 6059(a) of the Internal Revenue Code, referred to as the Code.
Attach to Form 5500 or 5500-EZ if applicable.
See separate Instructions.

Official Use Only
OMB No. 1210 - 0110

2005

This Form is Open to Public Inspection (except when attached to Form 5500-EZ)

For the calendar plan year 2005 or fiscal plan year beginning July 01, 2005**, and ending** June 30, 2006

If an item does not apply, enter "N/A." Round off amounts to nearest dollar.
Caution: A penalty of $1,000 will be assessed for late filing of this report unless reasonable cause is established.

A Name of plan
NATIONAL FUEL GAS COMPANY RETIREMENT PLAN

B Three digit plan number 001

C Plan sponsor's name as shown on line 2a of Form 5500 or 5500-EZ
NATIONAL FUEL GAS COMPANY

D **Employer Identification Number**
13-1086010

E Type of Plan: (1) ☐ Multiemployer (2) ☒ Single-employer (3) ☐ Multiple-employer

F ☐ 100 or fewer participants in prior plan year

Part I Basic Information (To be completed by all plans)

1a Enter the actuarial valuation date: July 01, 2005
b Assets

(1) Current value of assets	**b(1)**	$648,230,799
(2) Actuarial value of assets for funding standard account	**b(2)**	$623,219,690
c (1) Accrued liability for plans using immediate gain methods	**c(1)**	$579,775,377
(2) Information for plans using spread gain methods:		
(a) Unfunded liability for methods with bases	**c(2)(a)**	
(b) Accrued liability under entry age normal method	**c(2)(b)**	
(c) Normal cost under entry age normal method	**c(2)(c)**	

Statement by Enrolled Actuary (see instructions before signing):
To the best of my knowledge, the information supplied in this schedule and on the accompanying schedules, statements and attachments, if any, is complete and accurate, and in my opinion each assumption used in combination, represents my best estimate of anticipated experience under the plan. Furthermore, in the case of a plan other than a multiemployer plan, each assumption used (a) is reasonable (taking into account the experience of the plan and reasonable expectations) or (b) would, in the aggregate, result in a total contribution equivalent to that which would be determined if each such assumption were reasonable; in the case of a multiemployer plan, the assumptions used, in the aggregate, are reasonable (taking into account the experience of the plan and reasonable expectations).

Signature of actuary	Date
ROBERT DANESH	G 0506374
Print or type name of actuary	Most recent enrollment number
MERCER HUMAN RESOURCE CONSULTING	585-389-8701
Firm Name	Telephone number (including area code)
175 SULLY'S TRAIL, SUITE 301 PITTSFORD, NY 14534-4560	
Address of the Firm	

If the actuary has not fully reflected any regulation or ruling promulgated under the statute in completing this schedule, check the box and see instructions ☐

1d Information on current liabilities of the plan:

(1) Amount excluded from current liability attributable to pre-participation service (see instructions)	d(1)	
(2) "RPA '94" information:		
(a) Current liability	d(2)(a)	$659,270,011
(b) Expected increase in current liability due to benefits accruing during the plan year	d(2)(b)	$16,072,954
(c) Current liability computed at highest allowable interest rate (see instructions)	d(2)(c)	$659,270,011
(d) Expected release from "RPA '94" current liability for the plan year	d(2)(d)	
(3) "OBRA '87" information:		
(a) Current liability	d(3)(a)	
(b) Expected increase in current liability due to benefits accruing during the plan year	d(3)(b)	
(c) Expected release from "OBRA '87" current liability for the plan year	d(3)(c)	
(4) Expected plan disbursements for the plan year	d(4)	$43,218,648

2 Operational information as of beginning of this plan year:

a Current value of the assets (see instructions) — 2a — $648,230,799

b "RPA '94" current liability:

	(1) No. of Persons	(2) Vested Benefits	(3) Total benefits
(1) For retired participants and beneficiaries receiving payments	2,487	$384,309,039	$384,309,039
(2) For terminated vested participants	308	$12,411,028	$12,411,028
(3) For active participants	1,726	$209,569,330	$262,549,944
(4) Total	4,521	$606,289,397	$659,270,011

c If the percentage resulting from dividing line 2a by line 2b(4), column (3), is less than 70%, enter such percentage — 2c — %

3 Contributions made to the plan for the plan year by employer(s) and employees:

(a) Mo.-Day-Year	(b) Amount paid by employer	(c) Amount paid by employees	(a) Mo.-Day-Year	(b) Amount paid by employer	(c) Amount paid by employees
04/11/2006	$8,602,672				
02/27/2007	$11,397,328				

3 Totals (b) $20,000,000 (c)

4 Quarterly contributions and liquidity shortfall(s):

a Plans other than multiemployer plans, enter funded current liability percentage for preceding year (see instructions) — 4a — 101.9%

b If line 4a is less than 100%, see instructions, and complete the following table as applicable:

Liquidity shortfall as of end of Quarter of this plan year			
(1) 1st	(2) 2nd	(3) 3rd	(4) 4th

5 Actuarial cost method used as the basis for this plan year's funding standard account computation:

a ☐ Attained age normal **b** ☐ Entry age normal **c** ☒ Accrued benefit (unit credit)
d ☐ Aggregate **e** ☐ Frozen initial liability **f** ☐ Individual level premium
g ☐ Individual aggregate **h** ☐ Other (specify)

i Has a change been made in funding method for this plan year? ☐ Yes ☒ No

j If line i is "Yes," was the chage made pursuant to Revenue Procedure 95-51 as modified by Revenue Procedure 98-10? ☐ Yes ☐ No

k If line i is "Yes," and line j is "No" enter the date of the ruling letter (individual or class) approving the change in funding method

6 Checklist of certain actuarial assumptions:

a Interest rates for:

(1) "RPA '94" current liability

				5.90%	
	(2) "ORBA '87" current liability		a(2)	%	☐ N/A
b	Weighted average retirement age		6b	60	☐ N/A
			Pre-Retirement	Post-Retirement	
c	Rates specified in insurance or annuity contracts ☐ N/A	6c	☐ Yes ☒ No	☐ Yes ☒ No	☐ N/A
d	Mortality table code for valuation purposes:				
	(1) Males	d(1)	9	9	
	(2) Females	d(2)	9	9	
e	Valuation liability interest rate ☐ N/A	6e	8.25%	8.25%	☐ N/A
f	Expense loading ☐ N/A	6f	1.9%	%	☒ N/A
			Male	Female	
g	Annual withdrawal rates:				
	(1) Age 25	g(1)	8.00%	8.00%	
	(2) Age 40	g(2)	8.00%	8.00%	
	(3) Age 55	g(3)	8.00%	8.00%	
h	Salary Scale ☐ N/A	6h	6.11%	6.11%	☐ N/A
i	Estimated investment return on actuarial value of assets for the year ending on the valuation date		6i	3.7%	
j	Estimated investment return on current value of assets for the year ending on the valuation date		6j	9.7%	

7 New amortization bases established in the current plan year:

(1) Type of Base	(2) Initial Balance	(3) Amortization Charge/Credit

8 Miscellaneous information:

a If a waiver of a funding deficiency or an extension of an amortization period has been approved for this plan year, enter the date of the ruling letter granting the approval

b If one or more alternative methods or rules (as listed in the instructions) were used for this planyear, enter the appropriate code in accordance with the instructions

c Is the plan required to provide a Schedule of Active Participant Data? If "Yes," attach schedule. (see instructions) ☒ Yes ☐ No

9 Funding standard account statement for this plan year:
Charges to funding standard account:

		Outstanding Balance		
a	Prior year funding deficiency, if any		9(a)	
b	Employer's normal cost for plan year as of valuation date		9(b)	$9,017,364
c	Amortization charges as of valuation date:	**Outstanding Balance**		
	(1) All bases except funding waivers	($)	c(1)	
	(2) Funding waivers	($)	c(2)	
d	Interest as applicable on lines 9a, 9b, and 9c		9d	$743,933
e	Additional interest charge due to late quarterly contributions, if applicable		9e	
f	Additional funding charge from Part II, line 12u, if applicable ☐ N/A		9f	0
g	Total charges. Add lines 9a through 9f		9g	$9,761,297
	Credits to funding standard account:			
h	Prior year credit balance, if any		9h	$187,053,741
i	Employer contributions. Total from column (b) of line 3		9i	$20,000,000
		Outstanding Balance		
j	Amortization credits as of valuation date	($)	9j	
k	Interest as applicable to end of plan year on lines 9h, 9i, 9j		9k	$15,431,934
l	Full funding limitation (FFL) and credits			
	(1) ERISA FFL (accrued liability FFL)	l(1) $165,218,503		
	(2) "OBRA '87" FFL (155% current liability FFL)	l(2)		
	(3) "RPA '94" override (90% current liability FFL)	l(3)		
	(4) FFL credit before reflecting "OBRA '87" FFL		l(4)	
	(5) Additional credit due to "OBRA '87" FFL		l(5)	
m	(1) Waived funding deficiency		m(1)	

	(2) Other credits		m(2)	
n	Total credits. Add lines 9h through 9k, 9l(4), 9l(5), 9m(1), and 9m(2)		9n	$222,485,675
o	Credit balance: If line 9n is greater than line 9g, enter the difference		9o	$312,724,378
p	Funding deficiency: If line 9g is greater than line 9n, enter the difference		9p	
	Reconciliation account:			
q	Current year's accumulated reconciliation account:			
	(1) Due to additional funding charges as of the beginning of the plan	q(1)		
	(2) Due to additional interest charges as of the beginning of the plan year	q(1)		
	(3) Due to waived funding deficiencies:			
	(a) Reconciliation outstanding balance as of valuation date	q(1)		
	(b) Reconciliation amount. Line 9c(2) balance minus line 9q(3)(a)	q(1)		
	(4) Total as of valuation date		q(4)	
10	Contribution necessary to avoid an accumulated funding deficiency. Enter the amount in line 9p or the amount required under the alternative funding standard account if applicable		10	
11	Has a change been made in the actuarial assumptions for the current plan year? If "Yes," see instructions			[X] Yes [ ] No

Part II Additional Information for Certain Plans Other Than Multiemployer Plans

12	Additional required funding charge (see instructions):				
a	Enter "Gateway %." Divide line 1b(2) by line 1d(2)(c) and multiply by 100. If line 12a is at least 90%, go to line 12u and enter -0-. If line 12a is less than 80%, go to line 12b. If line 12a is at least 80% (but less than 90%), see instructions and, if applicable, go to line 12u and enter -0-. Otherwise, go to line 12b			12a	94.5%
b	"RPA'94" current liability. Enter line 1d(2)(a)			12b	
c	Adjusted value of assets (see instructions)			12c	
d	Funded current liability percentage. Divide line 12c by 12b and multiply by 100			12d	%
e	Unfunded current liability. Subtract line 12c from line 12b			12e	
f	Liabiity attributable to any unpredictable contingent event benefit			12f	
g	Outstanding balance of unfunded old liability			12g	
h	Unfunded new liability. Subtract the total of lines 12f and 12g from line 12e. Enter -0- if negative.			12h	
i	Unfunded new liability amount (% of line 12h)			12i	
j	Unfunded old liability amount			12j	
k	Deficit reduction contribution. Add lines 12i, 12j, and 1d(2)(b)			12k	
l	Net charges in funding standard account used to offset the deficit reduction contribution. Enter a negative number if less than zero			12l	
m	Unpredictable contingent event amount:			12m	
	(1) Benefits paid during year attributable to unpredictable contingent event	m(1)	0		
	(2) Unfunded current liability percentage. Subtract the percentage on line 12d from 100%	m(2)			
	(3) Enter the product of lines 12m(1), 12m(2), and 12m(3)	m(4)			
	(4) Amortization of all unpredictable contingent event liabilities	m(5)			
	(5)"RPA '94" additional amount (see instructions)	m(6)			
	(6)Enter the greatest of lines 12m(3), 12m(4), or 12m(5)			m(7)	
	Preliminary Calculation				
n	Preliminary additional funding charge: Enter the excess of line 12k over line 12l (if any), plus line 12m(6), adjusted to end of year with interest			12n	
o	Contributions needed to increase current liability percentage to 100% (see instructions)			12o	
p	Additional funding charge prior to adjustment: Enter the lesser of line 12n or 12o			12t	
q	Adjusted additional funding charge. (.0% of line 12p)			12u	

For Paperwork Reduction Act Notice and OMB Control Numbers, see the instructions for Form 5500 or 5500EZ. v2.3**Schedule B (Form 5500) 2005**

SCHEDULE C (Form 5500) Department of the Treasury Internal Revenue Service Department of Labor Pension and Welfare Benefits Administration Pension Benefit Guaranty Corporation	**Service Provider Information** This schedule is required to be filed under section 104 of the Employee Retirement Income Security Act of 1974. **File as an attachment to Form 5500.**	Official Use Only OMB No. 1210-0110 **2005** **This Form is Open to Public Inspection**

For the calendar plan year 2005 or fiscal plan year beginning July 01, 2005 **and ending** June 30, 2006

A Name of plan
NATIONAL FUEL GAS COMPANY RETIREMENT PLAN

B Three digit plan number 001

C Plan sponsor's name as shown on line 2a of Form 5500
NATIONAL FUEL GAS COMPANY

D Employer Identification Number
13 1086010

Part I Service Provider Information (see instructions)