STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

16-G-0257 - PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NATIONAL FUEL GAS DISTRIBUTION CORP FOR GAS SERVICE

EVIDENTIARY HEARING

Wednesday, October 5, 2016
Three Empire State Plaza
3rd Floor
Albany, New York 12223-1350

A.L.J. DAKIN LECAKES
Administrative Law Judge
Three Empire State Plaza
Albany, New York 12223-1350

16-G-0257 - NATIONAL FUEL GAS DIST. CORP - 10-5-2016

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16-G-0257 - NATIONAL FUEL GAS DIST. CORP - 10-5-2016

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I N D E X O F P R O C E E D I N G S

RICHARD FORD: Sworn
Examination by the A.L.J. 1151

KEVIN HOUSE; Sworn
Direct Examination by Mr. Miller 1157
Cross Examination by Ms. Woebbe 1240
Redirect Examination by Mr. Miller 1271
Recross Examination by Ms. Woebbe 1274

PANEL: Sworn (Raichel, Stolicky, Disalvo, Pasinella)
Direct Examination by Mr. Favreau 1279
Cross Examination by Mr. Miller 1341

A.L.J. LECAKES: On the record.

THE REPORTER: We are on the record.

A.L.J. LECAKES: My name is -- Administrative Law Judge Dakin D. Lecakes. I call case 16-G-0257 proceeding on motion of the commission as to the rates, charges, rules, and regulations for National Fuel Gas Distribution Corp. for gas services. We are here pursuant to a notice of evidentiary hearing issued by the secretary on September 21, 2016. Let's start by taking appearances from the attorneys starting with company.

MR. GREGORY NICKSON: For the company, Gregory Nickson and Bruce Miller of Cullen and Dykeman, LLP and Joseph Del Vecchio of National Fuel Gas Distribution Corporation.

A.L.J. LECAKES: And from Staff?

MR. JOHN FAVREAU: John Favreau, staff counsel, and with me is Bridget Woebbe and Jalila Aissi.

A.L.J. LECAKES: And from the Utility Intervention Unit?

MR. MICHAEL ZIMMERMAN: Michael Zimmerman and Kathleen O'Hare for the UIU.

A.L.J. LECAKES: From PULP?

MS. LISABETH JORGENSEN: Lisabeth Jorgensen and with me is Bill Yates.

A.L.J. LECAKES: And is Energy Mark's representative here today? Okay. Mr. Ford, can you identify yourself please?

MR. RICHARD FORD: I'm Richard Ford from Clarence, New York.

A.L.J. LECAKES: And I would also like to note the appearance of Michael Mager, M-A-G-E-R, who is with the law firm Couch, White LLP who has been participating in these proceedings representing multiple interveners. Mr. Mager is not here today. He has been excused from this afternoon and he will be joining us tomorrow at which time I expect him to enter his own appearance onto the record. All right.

Before we move on to taking any new motions, last week we held a teleconference prehearing for this case. At the time of the teleconference, staff and the company made a joint proposal to me to submit additional testimony on financial issues in this case. I granted the motion orally on the teleconference. Since then both the company and staff filed what we eventually agreed to call supplemental testimony. There were three pieces of testimony offered by the company, NFG, and there was one piece of supplemental testimony offered by staff.

Those will be put in the record when the

affidavits for those panels are accepted.

Are there any other preliminary motions to be entertained at this time?

I would like to turn now to confidentiality by correspondence dated September 16, 2016, National Fuel Gas submitted three sets of documents to which it requested protection from public disclosure under the New York State Freedom of Information Law, part 6 of the Commission's Regulations, and the Protective Order I issued in this proceeding by ruling dated July 1, 2016. In addition to Exhibits with the pre-file designation GCB-2EMC-3EMC-4 and CFP-5, the documents also included portions of testimony of NFG witness, Evan M. Crahen, C-R-A-H-E-N.

Earlier in these proceedings the Department of Public Staff -- Service Staff witness Daniel S. Gadomski, G-A-D-O-M-S-K-I, filed testimony and in Exhibit DSG-1 that also included portions for which Staff claimed confidential treatment was necessary based on an NFG claim of confidentiality sent to me when NFG served its response to Staff information request DPS-162. Supporting its request and now a motion, the company alleges that the information should not be publicly disclosed because it is either or both trade secret pursuant to commission

definition in a January 9, 2015 determination on appeal in case 14-M-0183 or because it constitutes confidential commercial information. Turning first to NFG Exhibit GCB-2 as well as Staff Exhibit DSG-1 and a portion of Staff witness Daniel Gadomski's testimony, the information contains excerpts taken from the company's annual review of officer compensation.

I find that the company has made a compelling case that both the information concerning officer's salaries and payroll as well as the information concerning NFG's incentive compensation structure are trade secrets under 16 NYCRR, section 6-1.3A, and the January 9, 2015 determination on appeal in case 14-M-0183. Release of such information could harm the company's shareholders and ratepayers by potentially increasing NFG's cost to do business. As such, it should be protected from public disclosure.

As to the Hay Group analyses that compare the competitiveness of NFG's officer compensation practices and the underlying empirical data, I agree with the company's position that the competitive harm to the Hay Group could result from public disclosure for the three reasons cited on page 5 of the NFG's September 16 correspondence; therefore, under the determination on

appeal issued August 13, 2014 in case 13-01288 cited by NFG on page 4 of its correspondence, the company has established the potential for competitive harm to another affected enterprise sufficient to establish trade secret and confidential commercial information protection in this case.

For exhibits pre-marked as EMC-3 and EMC-4 and the testimony portions of NFG witness Evan Crahen, the company has established that it is properly protected as confidential based on Article 14 of a working agreement between Liberty Consulting Group, NFG, and other parties including the New York State Public Service Commission. This document in its unsigned form is attached to correspondence from the Commission's secretary under Case 13-M-0449 on the Department's DMM system. The correspondence is addressed to Jay Lesch, L-E-S-C-H, of NFG and is dated June 27, 2014. Article 14 concerning use of information and confidentiality protects, among other things, any consultant generated documents including report drafts that are not final and consultant created work papers and non-final findings, conclusions or recommendations.

Finally, the exhibit pre-marked as CFP5 contains financial information related to an unregulated

competitive affiliate of NFG's, Seneca Resource Corporation. NFG states on page 6 of its September 16 correspondence that disclosure would allow financial market participants to gain confidential information about Seneca that would not otherwise be available to them and that Seneca's competitors would gain valuable information of Seneca that it would not have concerning its competitors. This showing is more than sufficient to establish protection of CFP5 as a confidential trade secret. All documents referenced in this ruling are therefore protected from public disclosure pursuant to the New York State Public Officer's Law and the Commission's Regulations.

This is my entire ruling on the confidential material in this case submitted through today.

For the record, no further written ruling apart from the hearing transcript will be issued. Additionally, where a confidential testimony appears in the transcript, two copies will be made for those days: A public redacted copy -- a public redacted copy and a confidential copy that will not be disclosed publicly. Let's go off the record.

[Off the Record]

A.L.J. LECAKES: On the record. Starting with NFG, we're going to start collecting affidavits of witnesses for which cross was not requested by any party and it will be affidavits accepting their testimony into the record and laying the foundation for their exhibits. Mr. Nickson?

MR. NICKSON: Thank you, Your Honor. The first affidavit is for company witness Jeremy R. Barber and for the record Mr. Barber prepared testimony entitled The Direct Testimony of Jeremy R. Barber consisting of eleven pages of questions and answers. Mr. Barber also prepared testimony entitled Rebuttal Testimony of Jeremy R. Barber which consists of seventeen pages of questions and answers. I ask that direct testimony and rebuttal testimony of Mr. Barber be incorporated into the record as if given orally today.

A.L.J. LECAKES: That's granted and I am opening the CD that was provided by the company with the testimony on it. Mr. Nickson, that's one affidavit covering both the direct testimony as well as the rebuttal testimony?

MR. NICKSON: That is correct.

A.L.J. LECAKES: All right. So the record should reflect at this point that the National Fuel Gas

Distribution Corporation pre-filed testimony CD has a folder on it called Company Direct Testimony. The first PDF file in there is listed as Barber Direct Testimony. That should go into the record at this point as if given orally today and then the second would fall under the rebuttal testimony and it will be Barber Rebuttal Testimony. We will mark the Barber affidavit as Exhibit 1.

DIRECT TESTIMONY OF JEREMY R. BARBER

1 Q. Please state your name and business address.

2 A. My name is Jeremy R. Barber. My business address is 6363 Main Street,
3 Williamsville, New York 14221.

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

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

7 Q. Describe briefly your educational background and experience.

8 A. In 2008, I graduated from the State University of New York at Brockport with a
9 Bachelor of Science degree in Business Administration. In 2009, I received a
10 Master of Business Administration degree from the Rochester Institute of
11 Technology, with a concentration in Operations Management. From 2010 to
12 2014, I worked for Citigroup as a Foreign Exchange Analyst. In 2014, I began
13 my employment with Distribution.

14 Q. Have you previously testified before the New York Public Service Commission?

15 A. No.

16 Q. What is the subject of your testimony?

17 A. I am providing testimony concerning Distribution's Revenues, the Operations and
18 Maintenance expense elements of Distribution's Labor and Benefits, and Taxes
19 Other Than Income.

20 **Revenues**

21 Q. What is shown on Exhibit___(JRB-1), Sheet 1?

22 A. Sheet 1 of Exhibit___(JRB-1) is the summary page of Distribution's revenues for
23 the twelve months ended December 31, 2015 and the twelve months ending
24 March 31, 2018. Column 1 presents the revenues actually recorded ("per
25 books") during the twelve months ended December 31, 2015 on the books of

Distribution. More detail is shown for the Historic Test Year on Exhibit___(JRB-1), Sheet 2.

The second column presents the adjustments to those "per book" revenues to bring the revenues to the amount projected for the Rate Year using projected Rate Year volumes at Distribution's current rates.

The third column represents the sum of Columns 1 and 2. See Exhibit___(JRB-1), Sheet 3 for more detail on Distribution's revenues at current rates for the proposed Rate Year volumes.

The fourth column represents the adjustment to price the projected Rate Year volumes at Distribution's proposed rates and the fifth column is the Rate Year volumes priced at Distribution's proposed rates. The fifth column is the sum of columns 3 and 4.

Q. Please describe how the revenues for the Rate Year at current rates were determined.

A. The Volume Forecast Panel has provided me with the projected Rate Year volumes by service classification by month from Distribution's 2015 Master Estimate. SC-21 Large Electric Generation volumes have been removed from the forecast. I have taken each service class's volumes and calculated the revenues by applying the rates currently in effect. For the SC-1, SC-2 HRAS, SC-2A EBD PTRA, SC-2B LICAAP, SC-3, SC-1 Aggregated Transportation, SC-2 HRAS Transportation, SC-3 Aggregated Transportation and DSS Aggregated Transportation classes, I used the Company's computer program which spreads anticipated service classification usage by block based on a historical bill frequency analysis for the class. The volumes by rate block were then multiplied by the base rates in effect since December 28, 2007 to develop base rate

1 revenues, which were then summed to yield base rate revenues by service
2 classification.
3 Q. Please continue with your description of the forecast of Rate Year revenues.
4 A. The customer count was supplied to me by the Volume Forecast Panel. I then
5 adjusted customer count to remove one half of the total number of final and initial
6 bills. This is necessary because the Volume Forecast Panel uses the number of
7 minimum bills to represent customer count. However, the number of minimum
8 bills includes both final bills and initial bills. If, during the year, a customer moves
9 within Distribution's service territory, then the number of minimum bills for that
10 year would include the same customer receiving an initial bill and final bill.
11 Subtracting one half of the total number of final and initial bills provides for a
12 more accurate and reasonable forecast of what the Company will actually collect
13 in minimum charge revenues.
14 The gas cost rates were the rates calculated for use in the Company's
15 2015 Master Estimate. The Revenue Tax was forecast by applying only the
16 Gross Receipts Tax ("GRT") to the appropriate revenues. The total GRT rate
17 charged to a customer is dependent upon whether or not the customer resides in
18 a city, town or village that applies an additional GRT tax to the customers. A
19 composite GRT rate based on the average GRT paid by customers on the
20 system was applied to the total of base rate revenues, Base Cost of Gas,
21 Delivery Adjustment Charge and the Revenue Adjustment Revenues.
22 Q. What is the Revenue Adjustment Factor shown in Exhibit___(JRB-1), Sheet 5?
23 A. The Revenue Adjustment Factor is a factor applied to the service classes for
24 which I used the Company's program to spread the total projected volume into

1 the rate blocks. It is calculated by comparing the calculated historic year
2 revenues by class with the actual revenues per class.
3 Q. What is the cause of the difference between the actual revenues and the
4 calculated revenues?
5 A. The main difference between the actual and the calculated revenues in the
6 historic year would be the allocation into the rate blocks. The actual revenues
7 are billed out at each individual's usage in the appropriate rate blocks. In order
8 to show the calculation of the historic year revenues, I used the Company's
9 OGIVE System to distribute the total volumes into each rate block. The OGIVE
10 System employs a bill frequency analysis in determining the distribution of bill, by
11 size and number, for a particular group of customers. The system captures bill
12 frequency data from the Company's mainframe computer on a monthly basis.
13 The system then takes the total forecasted monthly consumption and allocates
14 the volumes into the various blocks of consumption.
15 Q. Are there other causes for a difference between actual revenues and the
16 calculated revenues in the historic year?
17 A. Yes, adjustments to customers' bills would be the other reason for variance
18 between actual and calculated historic revenues.
19 Q. Why have you limited the use of the Revenue Adjustment Factor to those factors
20 under the absolute value of 1%?
21 A. The purpose of using the Revenue Adjustment Factor is to calibrate the
22 allocation of total projected Rate Year volumes into the rate blocks. If the historic
23 Revenue Adjustment Factor is greater than an absolute value of 1%, then it is
24 likely that the bigger factor in the difference between the actual and calculated
25 historic revenues involves adjustments made to the customers' bills during the

historic year. This can be seen in the industrial classes where there are fewer customers and an adjustment may have a greater impact than in a class where there are many customers.

Q. How are the LICAAP revenues forecasted?

A. I have used the Residential rates to calculate the LICAAP Rate Year revenues. I then included a decrease in revenues of $6,000,000 to simulate the $6,000,000 associated with the discount, arrearage forgiveness, and administration of the programs as discussed by the Customer Service Panel.

Q. Have you reflected the effect of rate true up and reconciliation mechanisms in forecasted revenues?

A. Yes, the forecasted impact of rate true up and reconciliation mechanisms for the twelve months ended March 31, 2018 are included in the present rate column. Distribution proposes to reset these mechanisms under its proposed rates.

Q. Please finish your description of the calculation of Rate Year revenues.

A. The base rate revenue, the gas cost revenues, the Revenue Tax revenues and the Revenue Adjustment Factor Revenues are added to equal the Rate Year revenues for each service class.

Operations and Maintenance Expense

Q. Please refer to Exhibit___(JRB-2), Schedule 1, Sheet 4, and explain in detail the computation of the adjustment to cost element associated with Labor.

A. I took the adjusted weekly payroll for the week ended December 26, 2015 as shown on Exhibit___(JRB-2), Schedule 1, Sheet 4. I multiplied that number by a factor of 52.14 weeks to derive an annualized base payroll of $40,245,500. To that I added the following items for the twelve months ended December 31, 2015:

1) summer and other payroll ($3,390,437), 2) temporary and part-time payroll ($217,591), and 3) overtime ($2,465,977).

I then annualized the adjusted supervisory payroll based on the pay period ended January 15, 2016 as shown on Exhibit___(JRB-2), Schedule 1, Sheet 4 and derived a result of $29,576,476. Next, I annualized the adjusted executive base payroll based upon the pay period ended December 31, 2015 as shown on Exhibit___(JRB-2), Schedule 1, Sheet 4 and derived a result of $2,310,548.

The payroll for January 15, 2016 was used for supervisory employees because it includes the actual increase to 2015 base salary. As a result, the percent increase for 2016 (shown in column (d) of Sheet 4), shows no increase relative to the historic test year.

Q. How did you determine the Rate Year Labor Expense?

A. To forecast the Rate Year labor expense, I started with the normalized payroll, as developed above. Under the direction of the General Compensation and Benefits Panel ("GCB"), I then added the annual effect of the contracted (2016) or forecasted (2017/2018) wage increases. As explained in the GCB Panel's testimony, labor negotiations for new union contracts will begin in late 2016. Forecasted wage increases have been held flat at 2016 levels. Those increases include: 1) 2.00% for Local 2154, 2154N and 2154S bargaining unit employees; 2) 1.5% for Locals 2199 and 2199 Part-Time employees; 3) 2.0% for Local 2199N employees; 4) 2.0% for Chapter 22 and 22S employees; 5) 1.5% for hourly non-bargaining unit employees; and 6) the annual impact of the contracted or forecasted 2016 through 2018 wage increases on overtime and temporary and part-time payroll. For non-union employees, a 3.0% projected compensation

1 increase effective January 1, 2017 and 2018 was provided by the GCB Panel.
2 These percentages should be updated once known.
3 The amount of the 2018 wages and wage increases not applicable in
4 the Rate Year were deducted. These calculations are detailed on
5 Exhibit___(JRB-2), Schedule 1, Sheet 4, columns (m) through (q).
6 Q. What was the next step in your calculation?
7 A. As seen in Exhibit___(JRB-2), Schedule 1, Sheet 3, I multiplied the calculated
8 total Rate Year payroll amount of $78,783,847 by 66.33%, the portion of payroll
9 that will be expensed, as developed on Sheet 5 of Schedule 1 and described
10 later in my testimony.
11 Q. Are there any further adjustments to Labor?
12 A. Yes. I have also added labor charged to New York from other jurisdictions as
13 well as Executive O&M to arrive at a total labor expense for the Rate Year of
14 $57,561,244. The difference between this figure and the normalized payroll
15 expense of $55,376,810 is $2,184,434, the Rate Year adjustment, shown at the
16 bottom of Sheet 1 of Schedule 1 in Exhibit___(JRB-2).
17 Q. How was the 66.33% O&M Expense Percentage calculated on
18 Exhibit___(JRB-2), Schedule 1, Sheet 5?
19 A. I have determined where labor was charged to during the historic year and
20 calculated the O&M percentage based on the labor charged to O&M versus total
21 labor.
22 The percentage for the Benefit costs has been calculated by further
23 adjusting the O&M Expense Percentage to reflect the benefit labor included in
24 the Benefit Loading Factor. This results in an O&M Expense Benefit Percentage
25 of 65.81%.

1 Q. What is your recommendation regarding the O&M Expense Percentage?

2 A. I recommend that the O&M Expense Percentage be updated later in this rate

3 case at the time of Brief on Exceptions to reflect the most current information.

4 Q. Please refer to the adjustment for Employee Benefits, as shown on

5 Exhibit___(JRB-2), Schedule 2. Please describe this Schedule.

6 A. Sheets 1, 2 and 3 are summary sheets; the detailed computations of Benefits are

7 shown on Sheets 4 through 6 and are explained below.

8 Q. Explain Sheet 3 of Schedule 2.

9 A. Sheet 3 shows the major cost elements in Account 926 (Benefits). Group Life

10 Insurance, Health Care, Dental, and Long Term Disability have been inflated for

11 the Rate Year. The Rate Year calculation for 401(K), SARS, Other Benefits, and

12 Benefits From Other Jurisdictions are explained later in this testimony. Please

13 refer to Mr. Weidner's testimony for a detailed explanation of the Pension and

14 OPEB items.

15 Q. Why is the Rate Year amount for SARS zero?

16 A. Based upon previous Commission orders, amounts related to Stock Appreciation

17 Rights and Stock Options have been removed from the Company's revenue

18 requirement.

19 Q. Why have you used an inflation rate of 4.27%?

20 A. See the testimony of R. Friedrich-Alf for an explanation of the inflation rate used

21 by the Company in this case.

22 Q. Please explain the adjustments to the 401(K) Plan as shown on Sheet 4.

23 A. The Company's match to the 401(K) Plan was annualized by taking the

24 payments for the Company's match for the 401(K) plan for the twelve months

25 ended December 31, 2015, calculating the average monthly payment and

1 multiplying by twelve. This results in an annual amount of $2,333,000, which
2 when multiplied with the 65.81% O&M Expense Benefit Percentage results in an
3 amount charged to expense of $1,535,000. When the historic cost of $1,492,005
4 is subtracted from $1,535,000, it results in a normalizing adjustment of $42,995.
5 To project the 401(K) Rate Year expense, the amount was increased
6 by the combined increase of the management compensation increase plus a 2%
7 participation increase. After inflating this amount, the 65.81% O&M Expense
8 Benefit Percentage was applied to determine the Rate Year amount of
9 $1,718,000. When the normalized amount of $1,535,000 is subtracted, it results
10 in a Rate Year adjustment of $183,000.
11 Q. Please explain the adjustment that is made on Sheet 5 of Schedule 2 in
12 Exhibit___(JRB-2).
13 A. I have analyzed Account 926 - Employee Benefits and have broken the account
14 into the major benefit types in order to properly forecast the different benefit
15 types. Other Benefits are the remaining charges to Account 926.
16 I projected the credits on Products 2107, 2108, 2111 and 2161[1] for the
17 loading of Sick and Other Approved Absences to labor dollars that are not
18 expensed. This increases Other Benefits by $618,056. I then inflated the
19 remaining Other Benefits by the inflation factor of 4.27%.
20 Q. Please describe your adjustment to Benefits from Other Jurisdictions as shown
21 on Sheet 6 of Schedule 2 in Exhibit___(JRB-2).
22 A. Distribution borrows labor from other jurisdictions within the National Fuel Gas
23 family of companies. Mainly this labor is used to maintain lines in rural areas at

[1] The above mentioned Products are the products that load labor with benefits. This is the how the benefits are transferred from O&M to non-O&M accounts like plant.

1 or near the Pennsylvania border. When an employee from National Fuel Gas
2 Supply Corporation ("Supply") or from the Pennsylvania Division of Distribution
3 ("Pennsylvania Division") works on New York's lines, labor is charged to the New
4 York Division. That labor is loaded with the benefits from the entity loaning the
5 labor. Each entity has its own loading factor. I have applied the specific loading
6 factor to the specific labor forecasted to be borrowed from Supply and the
7 Pennsylvania Division during the Rate Year to calculate the benefits related to
8 that labor that would be the responsibility of the New York Division of Distribution.
9 Compared to the actual benefits from other jurisdictions in the historic test year,
10 the Rate Year adjustment is calculated to be ($43,816).
11 Q. Please refer to Exhibit___(JRB-3). What does this exhibit present?
12 A. Exhibit___(JRB-3) presents the Taxes Other Than Income Taxes. Schedule 1 is
13 a summary of the taxes, showing their historic year amounts and the normalizing
14 and Rate Year adjustments. FICA and Unemployment Compensation will be
15 discussed later in this testimony. For a detailed explanation of Property Tax, see
16 Mr. Rizzo's testimony. For PCORI, Sales & Use Tax, and Miscellaneous Tax,
17 the historic per book amount was inflated by 4.27% to arrive at the figures for the
18 Rate Year.
19 Q. Please explain the adjustment for FICA taxes on Schedule 2 of Exhibit___(JRB-
20 3).
21 A. I have calculated the FICA Tax for the Rate Year payroll. I calculated the
22 effective increase in Rate Year gross payroll over the historic gross payroll and
23 applied that increase to the historic gross FICA Tax. Then the gross FICA tax
24 was multiplied by the O&M benefit percentage.

DIRECT TESTIMONY OF JEREMY R. BARBER

1 Q. Does this methodology estimate any changes in the FICA tax rate or the
2 maximum wage base?
3 A. No, it doesn't. Historically, any change to the tax rate or to the maximum wage
4 base isn't enacted into law until right before the New Year. The exhibit used
5 2016's FICA tax rates.
6 Q. Please explain the adjustment for Federal and State Unemployment
7 Compensation on Schedule 3.
8 A. The earnings base of $10,810,138 was determined by multiplying the number of
9 employees for the normalized period by the taxable wage base of $7,000. I then
10 multiplied this amount by the 2016 Federal Unemployment rate of .60%, to arrive
11 at a federal tax of $65,000.
12 I multiplied this amount by 65.81% O&M Expense Benefit Percentage
13 to determine the appropriate amount to be charged to expense of $43,000.
14 I calculated the New York State Unemployment Tax in the same manner,
15 using the 2016 tax rate of 1.70% and a wage base of $10,500. This produces a
16 Rate Year expense amount of $161,000 for New York State Unemployment Tax.
17 Q. Does this conclude your testimony?
18 A. Yes, it does.

Case 16-G-0257 Rebuttal Testimony of Jeremy R. Barber

Q. Please state your name and business address.

A. My name is Jeremy R. Barber. My business address is 6363 Main Street, Williamsville, New York 14221-5887.

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

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

Q. Have you testified previously in this case?

A. Yes. I provided Direct Testimony, Exhibits and workpapers regarding Distribution's Revenues, the Operations and Maintenance expense elements of Distribution's Labor and Benefits, and Taxes Other Than Income.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this rebuttal testimony is to provide analysis and recommendations regarding adjustments presented by New York State Department of Public Service Staff ("Staff") Accounting Panel and Staff witness Haslinger regarding O&M percentages used for forecasting Rate Year labor and benefits. I will also comment on Staff's adjustments to Other Benefits and the Staff Gas Rates Panel's

adjustments to Operating Revenues.

Labor

Q. Did you do a reasonableness check of Staff's Rate Year labor expense?

A. Yes. Mr. Haslinger's Exhibit___(RPH-2) shows total labor expense of $51,673,632 in the column *Per Staff Rate Year*. As seen on Exhibit___(SAP-1), Schedule 6, Page 1, Staff has made further adjustments to remove $1.585 in executive incentive compensation from O&M expense. This results in Staff's Rate Year Labor expense of $50.088 million as seen on Exhibit___(SAP-1), Schedule 2. I compared this to Distribution's Historic Test Year labor expense of $50.685 million from Exhibit___(JRB-2), Schedule 1, Sheet 1. While the Company does not agree with Staff's executive incentive compensation adjustment (as explained later in this testimony), including this adjustment would result in an overall decrease to labor expense from the Company's Historic Test Year. On top of this, Staff has imputed a two percent productivity adjustment.

Q. Is a decrease to labor expense in the Rate Year reasonable?

A. No. As seen in Exhibit___(JRB-2), Schedule 1, Sheet 4, the

Company projects, *at a minimum*, a 1.5% annual increase in base salary. The 1.5% increase applies to a small subset of union employees, while the majority of union employees (nearly 90%) should receive a 2% increase in base salary each year. The Company projects an average annual increase of 3% for supervisory employees. The Company has not forecasted a change to headcount in the Rate Year. Given these factors, it is not reasonable to expect Rate Year labor expense to decrease from the Historic Test Year.

Q. Do you agree with Staff's adjustment to remove $1.585 million for executive compensation from O&M expense?

A. No, this amount should remain in O&M expense. The rebuttal testimony of the General Compensation & Benefits Panel details the reasoning for rejecting Staff's adjustment.

<u>O&M Percentages & Adjustments</u>

Q. What does the O&M percentage represent?

A. The O&M percent is the ratio of expensed labor to total labor.[1] In Exhibit___(RPH-2), Mr. Haslinger has adjusted labor expense to

[1] Expensed (O&M) Labor supports Company operations such as answering phones and fixing leaks whereas non-O&M Labor is largely used to construct pipelines.

exclude $5.697 million for labor loaned to jurisdictions[2] in the Historic Test Year.

Q. Do you agree with Mr. Haslinger's adjustment to the Historic Test Year O&M labor expense percentage from 66.33 to 60.06%?

A. No. While the Company agrees that an adjustment to the O&M percent is necessary, it does not agree with Mr. Haslinger's percentage.

Q. What adjustment to the original O&M percent of 66.33% does the Company recommend?

A. The Company's calculation of the revised labor O&M percent is shown on Exhibit___(JRB-4), Schedule 1. The Company agrees that labor used in calculating the O&M percent should include the impact of Labor to Other Jurisdictions. Including Labor to Other Jurisdictions reduces the Historic Test Year O&M labor expense by $5,697,314 from $53,742,140 (cell D96) to $48,044,826 (cell J96) and increases the Historic Year non-O&M labor by $5,696,821 from $26,106,490 (cell D64) to $31,803,311 (cell J64). The net impact on total labor is a decrease of $493 from $79,848,630 (cell D98) to $79,848,137 (cell

[2] Labor loaned to other jurisdictions is to account for New York labor performing work for another jurisdiction.

J98). Dividing the labor expense of $48,044,826 by total labor of $79,848,137 produces a per book O&M percent of 60.17%. This percentage, however, needs to be adjusted further to account for other factors, which are explained in the following pages of testimony.

Q. In Exhibit___(RPH-1), Mr. Haslinger has removed $84,375 of "labor to benefits" from his calculation of the Historic Test Year O&M percentage. Do you agree with this adjustment?

A. The Company agrees that $84,375 should be removed from the O&M percent calculation. This adjustment is shown in cell K88 of Exhibit___(JRB-4), Schedule 1.

Q. Are there additional adjustments to the Historic Test Year O&M labor percent?

A. Yes. Executive O&M should be removed from the calculation of the O&M percent. The Company made this adjustment in its initial filing, but is reiterating this point since Mr. Haslinger has not made the adjustment in his Exhibit___(RPH-1) or Exhibit___(RPH-2). See cell L88 of Exhibit___(JRB-4), Schedule 1. The adjustment is necessary because the O&M labor percent is multiplied by the gross Rate Year labor forecast to determine labor expense in the Rate Year. The

executive base salary amount is excluded from the Rate Year labor forecast amount that is multiplied by the O&M factor because it is not gross labor. It is added below the product of that multiplication (gross labor x O&M%) because $2,310,548 already represents executive base directly charged to O&M for the New York Division. The result is a final O&M labor factor percentage of 58.94% (cell N96).

Q. Why is your revised percentage of 58.94% different from the 62.57% which Mr. Haslinger refers to on page 14 of his testimony?

A. The factor of 62.57% provided in my follow-up IR response to DPS-4 was the Company's initial revision to the actual labor O&M percentage prior to identifying additional adjustments. The Company's revised calculation did not include all products for Labor to Other Jurisdictions, as it only included 1054 (Common Expense Allocated Labor) in the amount of ($5,321,135). It did not include 1052 (Loaned or Borrowed Labor) and 1064 (Officer Secretary Allocated Labor – NYD), which were ($195,427) and ($180,752), respectively. These products were appropriately identified and included as Labor to Other Jurisdictions on Exhibit___(RMFA-2), Schedule 1, Workpaper Page 12, but were not shown on Workpaper

Page 11, which was the source for Exhibit___(JRB-2), Schedule 1, Sheet 5.

When O&M labor is allocated to other jurisdictions, an offsetting receivable is set up on a 146XXX account (non-O&M). The Company's original calculation inadvertently excluded the full offsetting receivable. There was a credit to O&M for labor to other jurisdictions of ($5,697,314), but a debit to the non-O&M receivable of only $1,478,437. The amount of $1,478,437 that was included represents the receivable for those National Fuel Gas Company ("Parent Company") subsidiaries that operate under accounting software separate from the PeopleSoft accounting system. The portion of the receivable that was not included represents Distribution's receivables from Parent Company subsidiaries that are "PeopleSoft entities," namely – Distribution-PA, Supply, Midstream, Empire, as well as the Parent Company. This amount of $4,192,421 was booked on product 9990. Product 9990 is an inter-unit product that the PeopleSoft accounting system uses to post transactions. Since this is not a labor-specific product, it was not displayed on the Company's original labor reclass workpapers. My Exhibit___(JRB-4),

Schedule 1 has now appropriately added product 9990 in column H, for an increase of $4,192,421 to the non-O&M total. Instead of a large decrease to overall labor, this results in a shift of labor from O&M to non-O&M accounts.

Q. Do you agree with Staff Accounting Panel's benefit O&M percentage of 59.45%?

A. No, I do not agree with Staff's percentage. The Company's revised labor O&M percent is 58.94%, as noted above. Consistent with the methodology explained on Page 12 of the Staff Accounting Panel's testimony, and consistent with Staff's adjustment, I have calculated a revised benefit O&M percent. Incorporating the changes I have addressed above (i.e. Labor to Other Jurisdictions), the amount of the adjustment is ($1,210,771) resulting in a Benefit O&M percent of 58.30%. This calculation is shown on Exhibit___(JRB-4), Schedule 2. This is the percentage that should be used in calculating the O&M expense of OPEBs, Pensions and 401(k).

Q. Do you agree with Mr. Haslinger's adjustment of $(5.888) million to the Company's rate year labor forecast?

A. No. Mr. Haslinger has overstated the impact of the Company's

inadvertent exclusion of Labor from Other Jurisdictions from the labor O&M percent. Exhibit___(JRB-2), Schedule 1, Sheet 1 from the Company's filing shows the original O&M labor expense at $57.561 million. Exhibit___(JRB-4), Schedule 3, Sheet 1 shows the revised labor expense of $52.007 million, accounting for the Company's updated labor O&M percent. This is a decrease of $5.554 million from the Company's original filing. In my rebuttal, I have also included exhibits that support the adjustments on Sheet 1. See Exhibit___(JRB-4), Schedule 3, Sheets 2 through 4.

Q. Why is the Company's adjustment to O&M labor less than Mr. Haslinger's adjustment of $(5.888) million?

A. Mr. Haslinger's adjustment is made up of two pieces, as seen in Exhibit___(RPH-2). The amount includes $5.802 million for Staff's forecasted Rate Year Labor to Other Jurisdictions, and $85,921 for Staff's forecasted Rate Year labor to benefits. First, Mr. Haslinger took a shortcut by removing $5.802 million from O&M in the Rate Year. Mr. Haslinger subtracted this amount from the bottom line O&M labor expense instead of multiplying his calculated O&M percent by the forecasted Rate Year total gross payroll. Mr.

Haslinger did not dispute the Company's method of using the O&M percent to forecast the Rate Year labor expense.

Regarding the labor to benefits component of Mr. Haslinger's adjustment, the Company asserts that this adjustment is incorrect. This amount represents dollars paid to employees who opt out of the Company's health care program. The Company appropriately reclassed this amount between the O&M cost elements of labor and benefits, as seen in the workpapers for Exhibit___(RMFA-2). Page 12 of these workpapers show ($84,375) in the column for "Labor to Benefits," while Page 15 shows $84,375 in the column "From Labor." In Exhibit___(SAP-1), Schedule 6, Page 1, Adjustment 5a, line (2), Staff Accounting Panel has incorrectly included this amount as a reduction to O&M. This is a mischaracterization of "labor to benefits," since the amount should remain in O&M expense.

Q. Are there other reasons that the Company's adjustment differs from Staff's?

A. Yes. In an August 4, 2016 letter to all parties, the Company indicated that it had identified several adjustments during the discovery process. Among these adjustments was $453,709 for Barcelona

awards that were erroneously excluded from the Company's Historic Test Year gross labor. Adding these awards increases the forecasted Rate Year gross payroll, which is multiplied by the labor O&M percent.

Q. Do you agree with the Staff Accounting Panel's adjustments relating to the benefit O&M percent? These are found in Exhibit___(SAP-1), Schedule 6, Page 1, Adj. 5, (b) through (d).

A. No. As discussed previously in this testimony, the Company does not agree with Staff's benefit O&M percent. As such, I recommend that Staff Accounting Panel's adjustments be rejected and the Company's revised benefit O&M percent of 58.30% be accepted.

Other Benefits

Q. Do you agree with Staff's adjustment of ($662,000) to Other Benefits?

A. We agree with Staff's reversal of the Company's $618,056 Rate Year adjustment, but recommend that Loading for Other Benefits be added to the inflation pool instead of following the percent labor increase. This would be consistent with the Company (and Staff's) treatment of Other Benefits.

For clarification, the Rate Year adjustment in Exhibit___(JRB-

2), Schedule 2, Sheet 5 did not account for approximately $500,000 for Officer Fringe Benefits in account 582170 (Other Benefit Credit) on product 2108. This amount represents the benefits loaded with executive labor charged to other jurisdictions. For union and supervisory employees, these credits are shown by benefit type – health care, dental, long term disability, etc. In those cases, the credits were included in the inflation pool. Officer loading for these various benefits is lumped together in one account – 582170. If we had identified these officer credits and reclassed them to the appropriate benefit types, they would have then been included in the inflation pool. This treatment justifies the Company's recommendation that Loading for Other Benefits should be inflated. Furthermore, if the Historic Test Year amount of Loading of Other Benefits hadn't included the officer credits, our Rate Year adjustment would have been much more in line with overall changes to historical actuals.

<u>Operating Revenues</u>

Q. Do you agree with Staff's adjustment of $5.614 million for low income discounts?

A. Yes, the Company agrees that Staff has calculated this adjustment appropriately. As pointed out in the Staff Gas Rates Panel's testimony, Staff has removed low income discounts from its revenue price out. With LICAAP, HRAS, and EBD customers priced out at full SC-1 tariff rates, revenues increased by $5.614 million. As explained further in their testimony, Staff has reflected the costs of its proposed low income program (including rate discounts) in O&M expense.

Q. Do you agree with Staff's total sales and transportation revenues of approximately $424.54 million and $114.62 million, respectively?

A. No. Staff's adjustments to the Company's forecast resulted in a significant adjustment to operating revenues – an increase of $15.597 million. As outlined in the Volumetric Forecast Panel's rebuttal testimony, the Company does not agree with Staff's aggressive customer growth or their projected increase in usage per account. The Company recommends less aggressive customer growth and a lower usage per account, based on longer-term trends.

Q. Have you compared Staff's usage per block to the Company's forecast?

A. Yes. It appears that Staff has over-allocated consumption to higher

margin blocks, which results in increased revenues.

Q. Please explain.

A. Staff performed its own redistribution of its total forecasted volumes for SC-1, SC-3, SC-1 Transportation, and SC-3 Transportation. While the Company agrees that Staff should use OGIVE analysis to distribute total volumes into the consumption blocks for each service class, it does not agree with Staff's results. The Company provided OGIVE curves to Staff by month, by service class. It appears that these curves were altered during the course of Staff's analysis, possibly to account for Staff's projected increased usage per account. Thus, Staff's approach is inconsistent with the Company's cumulative frequency methodology.

Q. What is an OGIVE curve?

A. In this context, an OGIVE curve is a cumulative frequency distribution based on historical customer usage data for a specific month and service class. Based on this curve, it's possible to predict how total forecasted volume for a service class would be broken down into the appropriate consumption blocks for a specific month. The Company has utilized the same Cumulative Frequency Method for over 30

years, and the Company believes its OGIVE curves are the most accurate curves to represent actual usage distribution across blocks for customers in its service territory. This breakdown of total volumes into the individual blocks is necessary for accurately pricing out delivery revenues.

Q. How do Staff's adjustments to the distribution of volumes by consumption block impact operating revenues?

A. Compared to the Company's distribution of volumes by block, Staff has included a higher percentage of volumes in the second block (as opposed to the tail block). Staff's alteration of the OGIVE curves has a greater impact in winter months, where consumption is greater. Since the second block for SC-1 has a much higher rate than the tail block, Staff's shifting of volumes to the second block increases revenues. The same logic applies for SC-3.

For illustrative purposes, I priced out Staff's forecast using the Company's OGIVE curves. In other words, customer counts and volumes were unchanged in my analysis. With the appropriate blocking of volumes, revenues decreased by approximately $450,000. This is summarized in Exhibit___(JRB-5), Schedule 1.

This schedule is supported by Exhibit___(JRB-5), Schedules 2 and 3. Schedule 2 shows Staff's revenue price out workpapers for SC-1, SC-3, SC-1 Transportation, and SC-3 Transportation, and SC-20 DSS Transportation. Schedule 3 shows the same service classes (less SC-20), but applies the Company's OGIVE curves. This appropriately changes the distribution of volumes into the rate blocks by month for each service class, resulting in decreased revenues.

Q. How is the revenue adjustment factor impacted by Staff's change in methodology?

A. As mentioned in my direct testimony, the purpose of using the Revenue Adjustment Factor is to calibrate the allocation of total projected Rate Year volumes into the rate blocks, using the historical OGIVE curves as the basis of the calculation. Since Staff has modified the underlying curves used to distribute volumes into the rate blocks, it is inappropriate for Staff to use the Company's original revenue adjustment factors to calibrate Rate Year revenues. Staff's price out included a total revenue adjustment of $165,145. The Company recommends that this adjustment be removed from operating revenues if Staff's adjusted OGIVE curves are used to

spread volumes to the rate blocks in this case. The calculation for Staff's revenue adjustment is included in Exhibit___(JRB-5), Schedule 2. This schedule shows the price out for select service classes from Staff's workpapers for Exhibit___(SGRP-3). Adjustment factors were applied to SC-1, SC-3 Transportation, and SC-20 as seen in Table 1.

Table 1. Staff Revenue Adjustment

Service Class	Revenue Adjustment
SC-1	$428,654
SC 3 Transportation	($239,986)
SC-20 DSS	($23,523)
Total	$165,145

Q. Does this conclude your Rebuttal Testimony?

A. Yes, at this time.

MR. NICKSON: Your Honor, before we move to the next witness, would you also like to address Mr. Barber's exhibit supporting his direct and rebuttal testimony?

A.L.J. LECAKES: Absolutely.

MR. NICKSON: Attached to the direct testimony of Mr. Barber were three exhibits consisting of JRB-1 through JRB-3. Also submitted with his direct testimony were work papers and I would ask that each of the exhibits and work papers be marked for identification as the next exhibits.

A.L.J. LECAKES: On the pre-filed exhibits list that I distributed before this hearing and NFG witness Jeremy R. Barber, we will mark the first one JRB-1 as Exhibit 2, JRB-2 as Exhibit 3, JRB-3 as Exhibit 4, work papers for JRB-1 as Exhibit 5, and that covers all of them. Correct?

MR. NICKSON: Correct.

A.L.J. LECAKES: Okay. So we are at Exhibit 5.

MR. NICKSON: And then also attached to Mr. Barber's rebuttal testimony were two exhibits that were pre-marked as JRB-4 and JRB-5 and I would ask that these exhibits be marked for identification.

A.L.J. LECAKES: They will be marked as Exhibit 6 and Exhibit 7 and those appear on page 12 of the list that I distributed before -- the exhibit list. Okay. The next?

MR. NICKSON: The what? Next witness is Patrick T. Boyle -- Boyle. Excuse me. I'd like to offer the testimony of Patrick T. Boyle into the record. Mr. Boyle prepared testimony entitled The Direct Testimony of Patrick T. Boyle which consists of 59 pages of questions and answers.

Mr. Boyle also prepared testimony entitled The Rebuttal Testimony of Patrick T. Boyle which consists of 17 pages of question and answers. I would ask the direct and rebuttal testimony of Mr. Boyle be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. The file Boyle Direct Testimony should go in the record at this point and then the file Boyle Rebuttal Testimony should follow. Are there any exhibits -- we will mark that affidavit as Exhibit 8.

DIRECT TESTIMONY OF PATRICK T. BOYLE

1 Q. Please state your name and business address.

2 A. My name is Patrick T. Boyle and my business address is 6363 Main
3 Street, Williamsville, New York 14221.

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

5 A. I am employed by National Fuel Gas Distribution Corporation
6 ("Distribution" or the "Company") as the General Manager of both
7 the Information Services and Telecommunications Departments.

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

9 A. I graduated from the State University of New York at Buffalo in May
10 1980, with a Bachelor of Science degree in Business
11 Administration. In August 1980, I joined Distribution as a Associate
12 Programmer Analyst in the Data Processing Department. In
13 September 1981 I was promoted to Programmer Analyst, and in
14 February 1984 I was promoted to Systems Analyst. The name of
15 the department was changed from Data Processing to Information
16 Service in 1984. In May of 1984 I received a Masters of Business
17 Administration from Canisius College in Buffalo NY. In August of
18 1986 I was promoted to Senior Systems Analyst, in April of 1987 to
19 Director, Systems Analysis, in April 1993 to Manager Planning &
20 Technology, and to General Manager Information Services in July

1 2009. I have always worked for Distribution in the Data
2 Processing/Information Services Department, having worked up
3 through the ranks to my current position as department manager.
4 In 2015 I was also given responsibility for managing Distribution's
5 Telecommunications Department. Between early 1988 and August
6 1990 I was the project manager responsible for the implementation
7 of the then "new" Customer Information System which Distribution
8 is currently replacing.
9 Q. Have you presented expert testimony before any regulatory
10 commissions?
11 A. No.
12 Q. What is the purpose of your direct testimony?
13 A. The purpose of my direct testimony is to explain why Distribution is
14 implementing a new Customer Information System and Mobile
15 Work Force Management System, and how that project has been
16 managed.
17 **Description of Current Customer Information System**
18 Q. Please describe National Fuel Gas Distribution Corporation's
19 ("Company" or "Distribution") existing Customer Information System
20 ("CIS") and Mobile Work Force Management System ("MWM").

1 A. Distribution's current CIS and MWM consists of eight distinct
2 computer applications, including: 1) Core CIS; 2) Customer
3 Service Order System ("CSO"); 3) Automated Dispatch Work Order
4 System ("ADS"); 4) Automated Dispatch Assignment & Monitoring
5 System; 5) Transportation Billing System ("TBS"); 6) Customer
6 Transportation System ("CTS"); 7) Operations Meter Warehouse
7 System ("OMW"); and 8) Customer Insight User Interface
8 ("Insight").
9 Q. What is the Core CIS?
10 A. The Core CIS is a mainframe- based application which was
11 developed in house using the NATURAL programming environment
12 and the database management system ADABAS both of which are
13 products of Software AG. This application handles all data aspects
14 associated with traditional utility customer service including; meter
15 reading, payment processing, billing, collections, and special
16 assistance programs (HEAP, county assistance, etc.). This
17 application was implemented in 1990.
18 Q. Please describe the CSO.
19 A. The CSO is a mainframe-based application written in NATURAL
20 and using ADABAS. This application is tightly coupled to Core CIS

1 and facilitates the creation and scheduling of all customer
2 requested service orders including: turn-ons, turn-offs, bill
3 investigations, and emergency orders. Scheduled manpower is put
4 into the application, allowing customer service representatives to
5 ensure that scheduled orders will be sent to the field as agreed to
6 with the customer. As the orders are sent to the field for execution,
7 the application bundles them by necessary execution skills and
8 geography to make efficient use of field resources. Configuration in
9 the CSO system allows for many settings including the relative
10 weighing of the effort required by different order types and the level
11 of staffing available for each service center by time block. This
12 application was implemented with Core CIS in 1990.
13 Q. What is the ADS?
14 A. The ADS is a client-server application which is tightly integrated
15 with the CSO system. This is the primary mobile application that
16 supports the ability of service personnel to receive and work orders
17 electronically on a daily basis. Scheduled orders are downloaded
18 before each shift into mobile devices. Emergency orders are
19 dispatched in real-time and sent directly to the service person's
20 device over a cellular network. The system also facilitates the

1 creation of daily timesheets for customer service personnel. The
2 system was originally implemented in 1994 as a C++ application
3 and was rewritten into VB.net in 2006.
4 Q. Please describe the Automated Dispatch Assignment & Monitoring
5 System.
6 A. The Automated Dispatch Assignment & Monitoring System is the
7 real-time monitoring aspect of the ADS system. It provides
8 Distribution's dispatch centers with the ability to monitor the
9 progress of emergency and high priority orders. The application
10 has a graphical display with a map showing the location of all
11 customer service vehicles and their status, and shows the location
12 of newly taken emergency orders. The dispatchers are then able to
13 dispatch and track the emergency orders in real-time. This
14 application is also a client-server application which was written in
15 C++ and implemented in 1994. It is tightly integrated with the CSO
16 and ADS applications.
17 Q. Please provide a description of the TBS.
18 A. The TBS is a mainframe-based application written in NATURAL
19 and using ADABAS. This application bills transportation and related
20 charges to gas marketers/aggregators. The application handles

1 customer enrollments, drops, usage, billing, security deposits, and
2 calculation of aggregated delivery quantities, etc. Data is passed
3 between TBS and the marketers via EDI transactions and files
4 made available to marketers on a special secure Distribution
5 website. This application was implemented in 1997 and is tightly
6 integrated with core CIS.
7 Q. What is the CTS?
8 A. The CTS is a mainframe-based application written in NATURAL
9 and using ADABAS. This application bills transportation, sales,
10 over-delivery, and other related charges for non-aggregated
11 transportation customers that are responsible for their own
12 imbalances. Generally, customers in CTS are large commercial,
13 industrial, or public authority accounts. This application was
14 implemented in 1989.
15 Q. What is the OMW?
16 A. The OMW is a mainframe-based application written in NATURAL
17 and using ADABAS. This application maintains information on
18 meter assets, including installation history and meter inspections. It
19 is the primary driver for meter testing, test sampling, and scheduled
20 meter replacements. The application is tightly integrated with core

1 CIS and was implemented in 1990.

2 Q. Please provide a description of Insight.

3 A. Insight was implemented in 2010 to prolong the life of core CIS
4 prior to an eventual replacement of the CIS system. This interface
5 presents internal call representatives with a modern web-browser
6 (point and click) interface versus the existing 3270 keyboard (not
7 mouse friendly) transactional screens. The new interface also
8 introduced structured process scripting to lead call representatives
9 through the appropriate transactions to ensure they deliver
10 consistent information to customers. This application was jointly
11 developed between Jacada Ltd and in-house staff using Jacada
12 Ltd's proprietary toolsets. It is tightly integrated with core CIS's
13 online screens.

14 **Reasons to Replace CIS and Expected Benefits**

15 Q. Why is Distribution replacing its CIS?

16 A. There are several reasons the Company is replacing its current
17 CIS, including: 1) the cumulative impact of system changes over
18 the past twenty-two years; 2) legacy technology issues; 3)
19 outdated/restrictive data models; 4) the obsolescence of paper-
20 based workflow; 5) the inability to obtain customer data for analysis

in a timely manner; 6) the inability to find the IT skillsets required to maintain the system; and 7) reduced leverage in negotiating software annual maintenance fees.

Cumulative Impact of System Changes

Q. Please discuss the cumulative impacts of the various changes made to the Company's current CIS.

A. In the twenty-two years between the implementation of Core CIS and late 2012, thousands of changes were made to the system as a result of changing business requirements, opportunities to improve customer service, changes in regulatory requirements, opportunities to gain efficiencies, and changes in expectations of customers and our commissions in regard to a customer's ability to access and share their data. The cumulative effect of over two decades of programming changes has caused the underlying logic to become quite complex and difficult to maintain. Distribution's ability to implement business changes requiring CIS system support have become more and more difficult to achieve. The difficulty manifests itself in cost prohibitive estimates for changes and an inability to meet business needs in a timely manner. This complexity has also significantly increased required testing to

1 ensure that even small changes do not introduce unintended
2 consequences on the larger system.
3 Q. How will replacing the Company's CIS address these cumulative
4 impacts?
5 A. The expected benefits of replacing the Company's CIS include
6 increased flexibility in Distribution's ability to be both proactive and
7 reactive to business changes in terms of what system changes can
8 and cannot be accomplished in a timely and cost effective manner.
9 *Legacy Technology Issues*
10 Q. Please discuss Distribution's legacy technology issues.
11 A. The underlying technical foundation - Software AG's database
12 management system ADABAS and programming language
13 NATURAL - was "state of the art" when the system was first
14 implemented 26 years ago, in 1990. However, today those
15 technologies present significant challenges in interfacing with
16 current web-based technologies. Customers today expect the
17 ability to go to a website where they can access information about
18 their gas account and request certain services (self-service).
19 Distribution first made certain self-serve features available to
20 customers in 2005 and enhanced those services again in 2010.

However, the technologies Distribution employed to make this work added another level of technology (Jacada Workspace technologies), again increasing the complexity of the application. This very common layering on more software approach to enable the interaction between older and newer technologies introduced more potential break points in the system, and adds costs in terms of incremental annual software maintenance fees for the new layer, and requires more information technology specialist labor to maintain.

Q. Will replacing the Company's CIS improve these legacy technology issues?

A. Yes. Implementing a new "uncluttered" system will reduce the risks of introducing unintended negative consequences with system changes. It will reduce the turn-around time for requested business changes - once Distribution's information technology support staff achieves homeostasis with the new system and becomes proficient with the SAP technologies.

Outdated/Restrictive Data Model

Q. How is the underlying design of the current Core CIS outdated/restrictive?

A. The underlying design of the core CIS system is primarily a "premise-centric" one, focused on the meters at a specific physical location which it uses to derive gas bills. If a customer has multiple meters on the same physical site, but one meter is for commercial use (a pizzeria downstairs) and the other meter is for residential use (the apartment upstairs), that location will look like there are two customers there (two different accounts are set up). A customer who has two or more properties receiving gas service which are not physically adjacent to each other, even if they are both using the gas for the same purpose (e.g. both residential), will again have two account numbers with a full set of data attributes for that customer on each. Distribution determines which accounts are owned by the same person or corporation by comparing account owner information across accounts and looking for matches.

Q. Please describe the difficulties with this “premise-centric” structure.

A. This "premise-centric" structure makes it very difficult to:

- present customers with cumulative views encompassing all of their accounts if they have more than one premise;
- present marketers with cumulative views of a specific customer's accounts, which that marketer has received permission from the

1 account owners to see;

2 • provide cumulative usage reporting; and

3 • establish a potential customer's credit worthiness when applying for

4 service.

5 Q. How are new CIS systems different?

6 A. Today's CIS systems are "customer centric", allowing for multiple

7 contracts (accounts) to be associated with a person or corporation.

8 This customer-centric model is required given the myriad of options

9 people have in purchasing and managing their energy and its

10 usage, and in determining what channel they want to use to interact

11 (receive bills, information, notices, etc.) with their local utility and/or

12 supplier.

13 Q. Does the Company's current Core CIS have additional limitations or

14 restrictions?

15 A. Yes. When the current system was implemented in 1990, the sizes

16 of fields in the underlying database were determined based on

17 business requirements and expected expansion in the future. A

18 few key fields in the database have become extremely restrictive

19 because they are referenced extensively throughout the application

20 and are not large enough to facilitate today's needs. The major

1 field at issue is the customer service class field, which was
2 designed as a two digit numeric field allowing for 99 service
3 classes, which in 1990 seemed large enough to handle long term
4 future growth. This customer data attribute is critical in determining
5 how to handle the customer within many CIS business processes.
6 With the implementation of many special income programs to assist
7 payment troubled customers, Distribution has utilized almost all of
8 the 99 available classes. Expansion of this field would require
9 modifying and testing hundreds of programs that reference the
10 field.
11 Q. Please describe the benefits of Distribution's new CIS vis-à-vis the
12 outdated/restrictive data model of the current CIS.
13 A. The Company's new CIS will position Distribution for the next
14 generation of service offerings whether initiated by customers,
15 market conditions, State Regulatory Commissions, or Distribution
16 itself. The underlying data model will enable significant flexibility in
17 rate design and the ability of Distribution to analyze customer data.
18 The newer technology enhances Distribution's ability to interact with
19 the multiple channels (web-based applications, mobile applications
20 on cell phones, social media applications, etc.), that customers

1 expect to use in communicating with their local utility company.

2 *Paper-Based Workflow Obsolete*

3 Q. Is Distribution's current CIS primarily paper-based?

4 A. Yes. Distribution's CIS application has many tests to ensure the
5 quality of consumption measurements and bill calculations. Each
6 evening when meter reading or bill calculation issues are detected
7 by the system, reports are generated requiring human review and
8 intervention for resolution. The process to handle such
9 interventions via the use of paper reports was a current practice in
10 1990. Such reports have been printed each day by supervisory
11 staff and individual report pages were handed out to employees for
12 resolution of the different tasks and exceptions in the application.
13 This greatly limits the visibility of this work by management.

14 Q. Please discuss the additional limitations of Distribution's current
15 paper-based CIS.

16 A. In the intervening decades, modern applications have progressed
17 such that the assignment and tracking of such tasks are completely
18 electronic. The identification of such cases, the assignment of the
19 cases, and the tracking of the performance in resolving such cases
20 are handled completely within an application. This allows

1 management to follow up on data errors and anomalies, by utilizing
2 electronic workflows. Supervisors can more evenly allocate work to
3 subordinates, can measure the performance of each employee,
4 and can ensure that the individual tasks are actually worked and
5 completed. The ability to determine if a group of tasks is completed
6 also helps utilities to remain in compliance with numerous, complex
7 and ever increasing regulations.
8 Q. How will a switch to a non-paper-based CIS benefit Distribution?
9 A. Distributions' new CIS will improve internal workflow providing
10 management the ability to know who has what work, and where
11 they are with that work in near real-time. Work can be shifted
12 electronically if events warrant the movement of work from one
13 employee to another for whatever reason.
14 *Inability to Obtain Customer Data for Analysis in a Timely Manner*
15 Q. Please discuss Distribution's ability to obtain customer data under
16 its current CIS.
17 A. For its day, the database management software ADABAS was a
18 step-forward in allowing multiple users to access and update
19 transactions on-line. As information technology matured,
20 expectations and needs of individuals both inside and outside the

1 utility to obtain and analyze CIS data increased, but the underlying
2 data access technology did not support the ability for non-technical
3 system users to interact with the data via any manner other than
4 report programs, which were created and maintained by
5 programming staff.
6 Q. How will this change with the Company's new CIS?
7 A. Key business users will be trained on how to create their own data
8 extracts and to create publicly available queries, enabling them to
9 self-serve.
10 *Inability to Find the IT Skillsets Required to Maintain the System*
11 Q. Is it difficult for Distribution to maintain the current CIS?
12 A. Yes. There are approximately two million lines of NATURAL code
13 in the mainframe-based components of this system. IT
14 professionals who are experienced in this technology are rapidly
15 aging out of the workforce and becoming scarce. Colleges and
16 universities have not offered courses in these mainframe "legacy"
17 technologies for almost ten years now. The lack of qualified
18 professionals available to perform work on "legacy" systems
19 presents serious challenges concerning Distribution's "legacy"
20 systems, which Distribution had to address to ensure the continued

1 future reliability of its CIS system. Distribution is forced to either
2 hire individuals and train them from the ground up on mainframe
3 and Software AG technologies, or compete for an ever-decreasing
4 in size group of experienced mainframe NATURAL/ADABAS
5 professionals. It is also difficult to attract recent IT college
6 graduates to a position maintaining technology that they perceive
7 as an "outdated" technology.
8 Q. Will Distribution have the same difficulties in maintaining a new
9 CIS?
10 A. No. Entry-level hires coming out of college with IT degrees will
11 have the academic background to support the technologies upon
12 which the new system is built. These new hires will be productive
13 sooner since the system they are hired to support is similar in
14 underlying technologies with the technologies they just learned in
15 college. Distribution will also be able to attract more technology
16 applicants to support the new system because the technologies
17 under the new system are current.
18 *Lack of Leverage in Negotiating Software Annual Maintenance Fees*
19 *(Software AG)*
20
21 Q. How has the current CIS impacted Distribution's ability to negotiate
22 software annual maintenance fees?

1 A. As the IT industry has moved away from mainframe-based
2 systems, software vendors like Software AG have lost significant
3 revenue to newer products. This translates into them passing back
4 higher annual maintenance fees because they are spreading their
5 fixed costs (and margin) across fewer customers. Due to the size,
6 critical nature, and inability of Distribution to practically swap out the
7 CIS system, Software AG knows they have Distribution in a
8 precarious position - leaving Distribution with very little leverage to
9 negotiate favorable annual increases to software maintenance fees.
10 Distribution had negotiated a long-term fixed price software
11 maintenance agreement with Software AG in 2012 which expires in
12 August of 2017. It was Distribution's plan to be off of the mainframe
13 totally (CIS is approximately 80% of the mainframe utilization) by
14 August 2017 to avoid what would most likely be a significant and
15 uncontrollable increase in annual software maintenance costs.
16 Q. How will the new CIS change improve Distribution's negotiating
17 leverage?
18 A. Distribution will have options in regard to software add-ons and
19 companies offering SAP consulting services due to a much wider
20 and growing installed base of SAP applications. This will give

1 Distribution better leverage in negotiating contracts for additional
2 software and/or services from firms who offer SAP related
3 consulting services.
4 Q. Please summarize why Distribution is replacing its CIS at this time.
5 A. Distribution has done its best to prolong the life of its existing CIS
6 system to avoid incurring the significant cost and implementation
7 risk of a new system. The current system will have been operating
8 just short of 26 years as of May 2016. While the system has
9 served Distribution and its customer base well, for all of the reasons
10 stated above, the system needs to be replaced to ensure the
11 continued long-term reliability of the Company's CIS function.
12 **Preparation for CIS Replacement Project**
13 Q. When did Distribution start preparing for its CIS Replacement
14 Project?
15 A. In the spring of 2006, Distribution had a CIS consulting firm (Micon
16 Inc.) do a presentation on the state of the CIS Industry. That
17 presentation and recurring annual reviews of CIS Industry trends
18 from the Gartner Group[1] led Distribution to pursue extending the

[1] Gartner, Inc. (NYSE: IT) is the world's leading information technology research and advisory company. They deliver technology-related insight to CIOs and senior IT leaders in corporations and government agencies in approximately 10,000 distinct enterprises worldwide. Founded in 1979, Gartner is headquartered in Stamford, Connecticut, USA,

1 life of our CIS system versus pursuing a replacement at that time.
2 In February of 2010, Distribution invited IBM in to do a presentation
3 on the state of CIS systems. Based upon that presentation and
4 upon our continued review of CIS materials from the Gartner
5 Group, it appeared that two companies had emerged as offering
6 the tier-one products for utility CIS applications. Those companies
7 were Oracle and SAP.
8 Q. Which replacement option did Distribution select?
9 A. In the fall of 2011, Distribution accepted an offer From Oracle
10 Corporation for them to conduct a program called "Oracle Insight"
11 focusing on a potential CIS replacement.
12 Q. Please describe the Oracle Insight program's methodology.
13 A. The program's four step methodology included: 1) industry
14 perspective; 2) discovery; 3) solution design; and 4) solution
15 presentation.
16 Q. Please explain the industry perspective component of Oracle
17 Insight's methodology.
18 A. Oracle Insight facilitates discussions with customer executives
19 about the trends, best practices, challenges, and opportunities

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and has 7,600 associates, including more than 1,600 research analysts and consultants, and clients in 90 countries.

1 particular to the customer's business.

2 Q. Please explain the discovery component of Oracle Insight's

3 methodology.

4 A. The Oracle Insight team visits the customer site to study

5 capabilities—in personnel, processes, and technology—that can be

6 leveraged in an improved strategy. The team uses proprietary

7 Oracle intellectual property and industry-specific frameworks in its

8 assessments.

9 Q. Please explain the solution design component of Oracle Insight's

10 methodology.

11 A. A solution combining best-practice processes and supporting

12 technology moves the client toward better-aligned strategy. The

13 design includes a time-to-benefit analysis and an implementation

14 plan.

15 Q. Please explain the solution presentation component of Oracle

16 Insight's methodology.

17 A. The Oracle Insight team works with the client to create an executive

18 presentation that pinpoints the business benefits and value drivers

19 of the solution, along with detailed information supporting the

20 recommendation.

1 Q. How did Distribution evaluate the Oracle Insight option?

2 A. Distribution worked with Oracle consultants over a three-month
3 period and completed the program in December 2011. From the
4 beginning, when Oracle offered the no charge program to
5 Distribution, it was understood that the results would be heavily
6 biased toward the Oracle CIS solution. Since the Oracle solution
7 was one of the two tier-one solutions, Distribution assembled a
8 cross functional team of business experts to invest the time and
9 effort believing: (a) it was an excellent opportunity for us to learn
10 about what the "new" CIS applications could and could not do
11 relative to our existing CIS and (b) Distribution would likely be
12 evaluating the Oracle solution when the actual project selection did
13 occur in the future. While Distribution did not agree with the
14 cost/benefit analysis presented by Oracle in the final report, the
15 exercise was very valuable in helping Distribution understand what
16 the current CIS applications offered. The exercise provided
17 Distribution with valuable knowledge to use when it began to
18 developing its CIS RFP in the following year.

19 **Project Initiation and Software/Systems Integrator Selection**

20 Q. What was Distribution's process for initiating the CIS replacement

1 project?

2 A. Early in 2012 Distribution established the following guiding

3 principles for its CIS replacement project:

4 • A CIS project executive steering committee would be formed to

5 ensure the proper levels of corporate governance and establish a

6 commitment to mitigate risk.

7 • The CIS replacement project would be designed to be as least

8 disruptive as possible from the customer perspective.

9 • Distribution would retain the services of an "independent"

10 consulting firm with expertise in guiding utilities in preparing and

11 evaluating a CIS RFP, selecting a CIS application (the software),

12 and selecting a qualified systems integrator. "Independent"

13 meaning the firm did not act as an agent for either Oracle or SAP

14 and did not offer CIS systems integration services themselves.

15 • Distribution would retain a systems integrator to function as the

16 "general contractor" for the project, meaning Distribution would

17 manage that relationship, and that contractor would be accountable

18 for all sub-contractors.

19 • Distribution would retain the services of a legal firm with significant

20 expertise in negotiating software licensing, software maintenance

1 contracts, and the software systems integration services.

2 • The RFP would be released to a finite list of system integration
3 firms, instructing them to respond with either an Oracle or SAP
4 proposed solution (or they could submit two separate responses
5 one with the Oracle solution and one with the SAP solution).

6 • The RFP responses would include a list of the software products
7 required, but the pricing responses would not include any costs for
8 the acquisition of that software. Distribution would negotiate
9 directly with either Oracle or SAP depending upon which software
10 solution was selected.

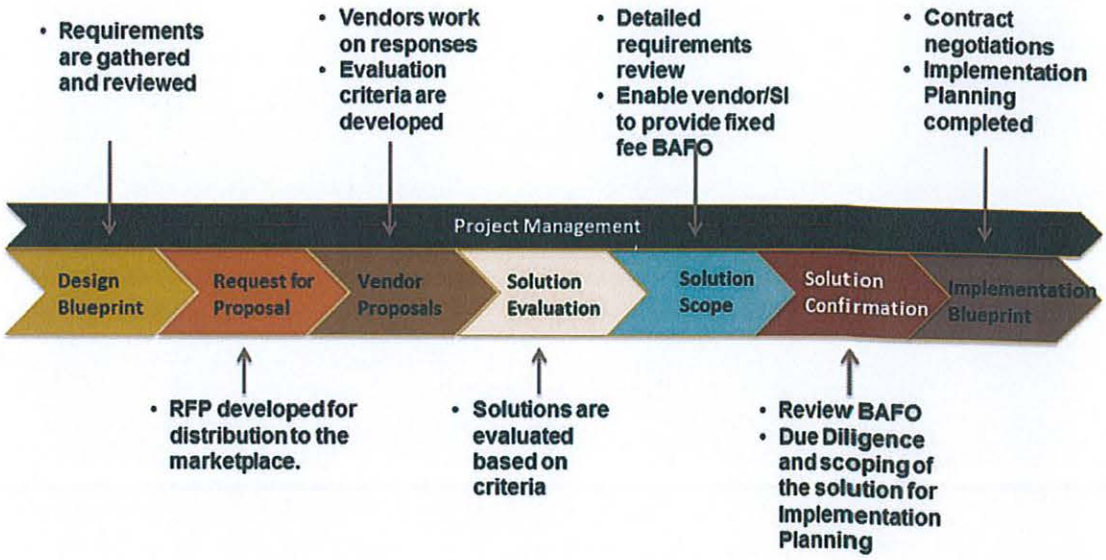
11 • RFP responders would be instructed to submit fixed price bids
12 based on milestone completions for payments.

13 • An important theme in the RFP would be to ensure knowledge
14 transfer occurred during the project from the systems integrator to
15 Distribution. This would enable Distribution to sever ties with the
16 systems integrator at some finite point after implementation,
17 enabling it to support the system on its own.

18 Q. Who did Distribution hire to assist it with its CIS RFP and systems
19 integrator selection?

20 A. During the second half of 2012, Distribution evaluated two

1 independent firms to assist it in the creation, release, and
2 evaluation of its CIS RFP and systems integrator selection. In
3 November of 2012, that contract was awarded to Five Point
4 Partners, LLC ("Five Point") of Atlanta, Georgia.
5 Q. Which law firm did Distribution select to negotiate its large long-
6 term software acquisition/maintenance agreements and system
7 integrator services?
8 A. In December of 2012, Distribution retained the legal firm of Jones
9 Day in Washington DC for its expertise in negotiating large long-
10 term software acquisition/maintenance agreements and system
11 integrator services.
12 Q. Please describe Five Point's procurement methodology.
13 A. Below is an illustration of the Five Point procurement methodology:



Q. How were the requirements of the RFP developed?

A. During December 2012, the Company held 34 workshops to identify current and future state requirements/processes to be outlined in the RFP, including 8 days of feature/function workshops to capture functional and technical customer information and billing requirements. Over 50 Distribution employees and subject matter experts contributed to identify, evaluate, and document over 2,800 Company requirements across 19 functional areas that were subsequently loaded into Five Point's STAR™ Tool (Selection Tool for Assessment and Requirements). These were then used for analysis on how well the current system meets the needs of the business, as well as to develop a scope baseline for the proposed

1 replacement effort.

2 Q. How was the RFP drafted?

3 A. Distribution and Five Points collaborated to draft a comprehensive
4 RFP consisting of 29 specific sections and 12 attachments
5 organized as follows:

6 • General Summary of RFP – Including sections on Proposal
7 Summary, Scope of Work, Timeline, and Minimum Requirements.

8 • Background Information – Including sections on corporate
9 structure, service territory, customer profile, and relevant
10 system/process/staffing data.

11 • Definition of Work – Including sections on Functional Components,
12 Interfaces, Data Access, and Solution Requirements
13 (Architecture/Implementation/Support).

14 • Proposal Submission Instructions – Including General Instructions,
15 Proposal Format, and Submission Requirements.

16 • Schedule of Events – Including sections on Key
17 Dates/Deliverables, RFP Process Details, and Evaluation
18 Criteria/Process.

19 • Terms and Conditions – Including sections on General T&Cs.

20 • Appendices – Including Response Templates, Pricing Sheets,

1 STAR Instructions, Process Documentation, Report Listings, and

2 Bill Images.

3 Q. When was the RFP released?

4 A. The RFP was released in January 2013 to Oracle, SAP, and 17

5 industry-leading systems integration solution providers.

6 Q. What were the key dates set forth in the RFP?

7 A. The key dates listed in the RFP were:

8

Activity	**Due Date**
Notice of intent to respond to RFP	Jan. 15, 2013
Solution Providers' written RFP clarification requests	Jan. 18, 2013
Pre-Proposal telephone conference	Jan. 18, 2013
Proposal addendum issued re: written responses to RFP clarification requests	Jan. 29, 2013
Proposals Due	Feb.7, 2013
Evaluation of Proposals against Minimum Requirements	Feb. 8 – 13, 2013
Evaluation of Proposals February 8 – March 7	Feb. 8 - Mar. 9, 2013
Select short list solution(s) March 8	Mar. 8, 2013
CIS and MWM system demonstrations	Apr. 15-26, 2013
Solution Integrator interviews	May 6 – May 10
Select solution finalist(s)	May 31, 2013
Detailed product and scope	Jun. 10-21, 2013
Revised statement of work (Best & Final Offer)	Jul. 8, 2013
Contract reviews, site visits & other due diligence	Jun. 24 – Aug. 2, 2013
Contract negotiations	Jun. 24 – Aug. 2, 2013
Presentations to management by the selection committee & execution of Contracts	Early August 2013
Project Start of Engagement	Sept. 3, 2013

9

1 Q. Were any of these dates modified?

2 A. Yes. The proposal due date was extended from February 7th to

3 February 21th for invited bidders as a result of clarification

4 questions from multiple RFP recipients. All questions and

5 responses were made available to all RFP recipients. As a result of

6 that extension, the actual dates for key events and results were as

7 follows:

8

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1

Event	Date Completed	Result
Proposals Due	Feb.21, 2013	11 Full Responses Were Received, 4 with Oracle solutions and 7 with SAP solutions.
Evaluation of Proposals against Minimum Requirements	Feb. 28, 2013	4 Responses Cut (7 Remaining, 3 Oracle and 4 SAP)
Select short list solution(s) March 8	Mar. 22, 2013	3 Responses Cut (4 Remaining, 1 Oracle and 3 SAP)
CIS and MWM system demonstrations	May 6 & 7, 2013 May-13-14, 2013	Presentations by Oracle & SAP
Solution Integrator interviews	May 8-17,2013	Presentations by Four Finalists
Conduct reference checks and a site visit on final four.	Jun. 24 – Aug. 2, 2013	Gain other clients feedback on how the integrator had performed on their CIS project.
Select solution finalist(s)	June. 21, 2013	Selected primary (HCL/SAP) and secondary (Quintel/SAP).
Present primary and secondary recommendations to Executive Steering Committee for Approval	Jul. 2, 2013	Approval to begin negotiations with primary recommended.
Develop Detailed Statement of Work (SOW) for Systems Integrator Contract	Jul. - Sept. 2013	Finalize SOW as baseline for what HCL must deliver.
Execution of Contracts	Sept. 27, 2013	Executed contracts with SAP to acquire software solution and HCL to act as systems integrator.
Project Start of Engagement	Dec. 2013	Initial HCL staff on-site.

2

1 Q. Please discuss the CIS and MWM system demonstrations by
2 Oracle and SAP?
3 A. The on-site software demonstrations by Oracle and SAP in May
4 gave both vendors the opportunity to demonstrate their solution's
5 strengths relative to the RFP's requirements and to differentiate
6 their product from the other. These software product
7 demonstrations were conducted across a number of functional
8 areas for both CIS and MWM, with SAP scoring higher than Oracle
9 consistently across the board.
10 Q. What topics were covered by the presentations made by the four
11 RFP finalists?
12 A. The full day on-site presentations by the finalists occurred in May
13 2013 covered the following topics:
14 • Executive Overview of the Proposed Solution;
15 • Project Management;
16 • Data Migration & Conversion;
17 • Change Management;
18 • Business Rule Configuration & Development;
19 • Distribution Targeted Q&A;
20 • Testing, Acceptance, Go-Live, Stabilization, & Knowledge Transfer;

1 • Distribution Scenario-Based Q&A; and

2 • General Q&A.

3 Q. Did Distribution review the four finalists' references?

4 A. Yes. During June and July of 2013 the CIS procurement team

5 conducted reference checks on the four finalists. The reference

6 checks were conducted primarily via conference calls and included:

Potential SI and Solution Proposed	Referenced Company(s)
Accenture (Oracle)	Baltimore Gas & Electric
Deloitte (SAP)	Puget Sound Energy
HCL (SAP)	HydroOne, Fortis BC, Hawaiian Electric Company, Sacramento Municipal Utilities District, Snohomish County Public Utilities District, &TXU
Quintel (SAP)	United Illuminating and Public Service Electric & Gas (New Jersey)

7

8 Distribution also had multiple conference calls with Gartner Group

9 experts to get information on specific topics mentioned during the

10 presentations from Oracle and SAP, and from comments heard

11 during the reference checking calls.

12 **RFP Evaluation Methodology**

13 Q. Please describe how the RFP evaluation methodology was

14 developed.

15 A. A structured and proven evaluation methodology was developed by

1 the Distribution team and approved by Distribution Leadership,
2 based on samples, templates and expertise provided by Five Point.
3 Distribution worked to develop evaluation criteria that analyzed
4 components it believed mitigated risk and emphasized variables
5 which were critical to project success. Distribution established and
6 weighted fifteen different criteria, grouped into four categories, in
7 order to evaluate each of the proposed solutions.
8 Q. What were the final evaluation criteria?
9 A. The criteria, with associated weighting, included: 1) Qualifications
10 and Experience (10%); 2) Project Approach and Risk Assessment
11 (35%); 3) Track Record of Performance (25%); and 4) Proposed Fit
12 to Distribution Business Requirements (30%).
13 Q. Please describe how Qualifications and Experience were assessed.
14 A. This portion of the evaluation combined four common Five Point
15 evaluation categories, as outlined below:
16 • Proposal responsiveness – Examines how well bidders followed
17 instructions, asked relevant questions, and provided timely
18 responses to deadlines.
19 • Company Profile – Examines years in business, years
20 implementing CIS and Mobile Workforce Systems, Size of Practice,

1 and Financial Viability.

2 • Qualifications & Experience – Reviews items such as experience
3 on similar engagements and experience on projects involving
4 multiple jurisdictions and multiple fuels.

5 • Agreement with the Company's proposed terms and conditions
6 (T&Cs) – This dimension considers how well each bidder's
7 response will align with Distribution's proposed legal and
8 contractual requirements.

9 Q. How were Project Approach and Risk Assessment evaluated?

10 A. This category encompassed the six standard Five Point dimensions
11 as outlined below:

12 • Project Pricing – Examines how well bidders understand the
13 commercial marketplace and conform to industry pricing ranges.

14 • Project Approach – Typical components include areas such as
15 architecture, business process re-design, business readiness
16 assessment experience, configuration, data conversion, enterprise
17 architecture, go-live and stabilization, project management,
18 software development, training, testing and transition.

19 • Technical Solution – Examines how robust the proposed solution is
20 in meeting technical requirements while conforming to industry

1 standard technical architecture approaches.

2 • Project Timeline – Considers factors such as reasonableness of
3 schedule and project plan relative to complexity of project

4 • Project Resources – Considers factors such as key resources
5 identified, acceptable staffing levels, required/proposed Distribution
6 staffing levels, proposed SI organizational structure, and SAP
7 CRMB installation experience.

8 • Risk Assessment – Examines all components of proposed solution
9 approaches to identify the most successful options posing minimal
10 or limited risk.

11 Q. What did Distribution evaluate as part of the Track Record of
12 Performance?

13 A. This facet enabled the Distribution project team to gain insights into
14 the ability of each bidder in terms of both Technical Competencies
15 and Behavioral Attributes.

16 Q. How were these criteria analyzed?

17 A. The Track Record of Performance combined four individual
18 evaluation dimensions as outlined below:

19 • Oral Presentations – Considers factors such as the bidder's
20 approach to project activities, tools & accelerators, responses to

1 scenario-based questions, likelihood that each of the bidder's staff
2 would work well with Distribution, and perceived differences
3 between bidder's presented materials and RFP response.
4 • Product demonstrations – Considers software product factors such
5 as look and feel, efficiency, ease of use, flexibility, and
6 customization in meeting organizational needs.
7 • Reference Checks – Enables the Distribution project team to better
8 understand the ability of each bidder in areas such as software
9 implementation performance, ability to work as a unified team, and
10 ability to apply the proposed methodologies and project
11 management approach.
12 • Site Visits – Enabled the Distribution project team to visit previous
13 vendor implementations and consider factors such as ability to
14 implement SAP CRM&B software, and ability to work well with
15 utility staff.
16 Q. How was the Proposed Fit to Distribution Business Requirements
17 evaluated?
18 A. This dimension considered the degree to which each bidder's
19 response to the over 2,800 business requirements fit with
20 Distribution's request. Additionally, Five Point's sophisticated and

1 proprietary software was used to evaluate each system integrator's
2 forecasted level of software customization.
3 Q. Based on its evaluation of the RFP responses, who did Distribution
4 select as the system integrator?
5 A. The Company selected HCL.
6 **Project Governance, Management, and Timeline:**
7 Q. Why did Distribution select HCL as the system integrator?
8 A. One of the reasons Distribution selected HCL was that HCL had
9 had a well-developed project methodology and software tools to
10 support their methodology. HCL's proprietary Project Support
11 Environment tool (APSE) enabled the project to keep all of the
12 functional documentation, technical documentation, deliverables,
13 risks, actions, various project status reports, test result, etc., in a
14 well-organized centralized repository available to all team
15 members. APSE also supported electronic workflow and tracking
16 of all work products which project management used extensively.
17 Q. How was the Statement of Work for the HCL contract developed?
18 A. The Statement of Work in the HCL contract was based on fourteen
19 project milestones, each of which contained a set of specific
20 deliverables which needed to be completed and submitted to

1 Distribution for approval. The entire contract was based on a fixed
2 price bid, with payments being earned by HCL as milestones were
3 accepted and approved by Distribution. The contractual milestones
4 were representative of a traditional system development lifecycle
5 approach targeting an implementation date of early July 2015, and
6 were as follows:

Milestone	**% of Total**	**Original Targeted Completion Date**
M1 - Project Preparation Complete	10%	December - 2013
M2 - Design Workshops Completed	5%	May - 2014
M3 - Strategy and Plan Materials Complete	5%	May - 2014
M4 - Business Blueprint Complete	10%	June - 2014
M5 - System Configuration Complete	5%	February - 2015
M6 - Functional and Technical Specifications Developed and Approved	5%	December 2014
M7 - Testing Complete	5%	March - 2015
M8 - Training Materials Developed and Approved	5%	April - 2015
M9 - Realization Phase Complete	10%	May - 2015
M10 - UAT Completed and Approved	5%	June - 2015
M11 - Legacy Data Migrated & Approved	5%	July -2015
M12 - Scheduled End-User Training Completed and Approved	5%	July 2015
M13 - Final Prep. Phase Complete	10%	August - 2015
M14 - Final System Acceptance (6 Months after Go Live)	15%	January - 2016
Total of Milestones	100%	

7

8 Q. Please discuss the first project milestone.

9 A. The first milestone encompassed project planning and

management control deliverables (e.g., establishment of the Project Management Office (PMO), development of the project charter, introduction of the tools and techniques to be used to document and track all project activities, documentation of the roles and responsibilities for team members, etc.).

Q. Please describe the governance structure and project organization.

A. Please see the illustration below:

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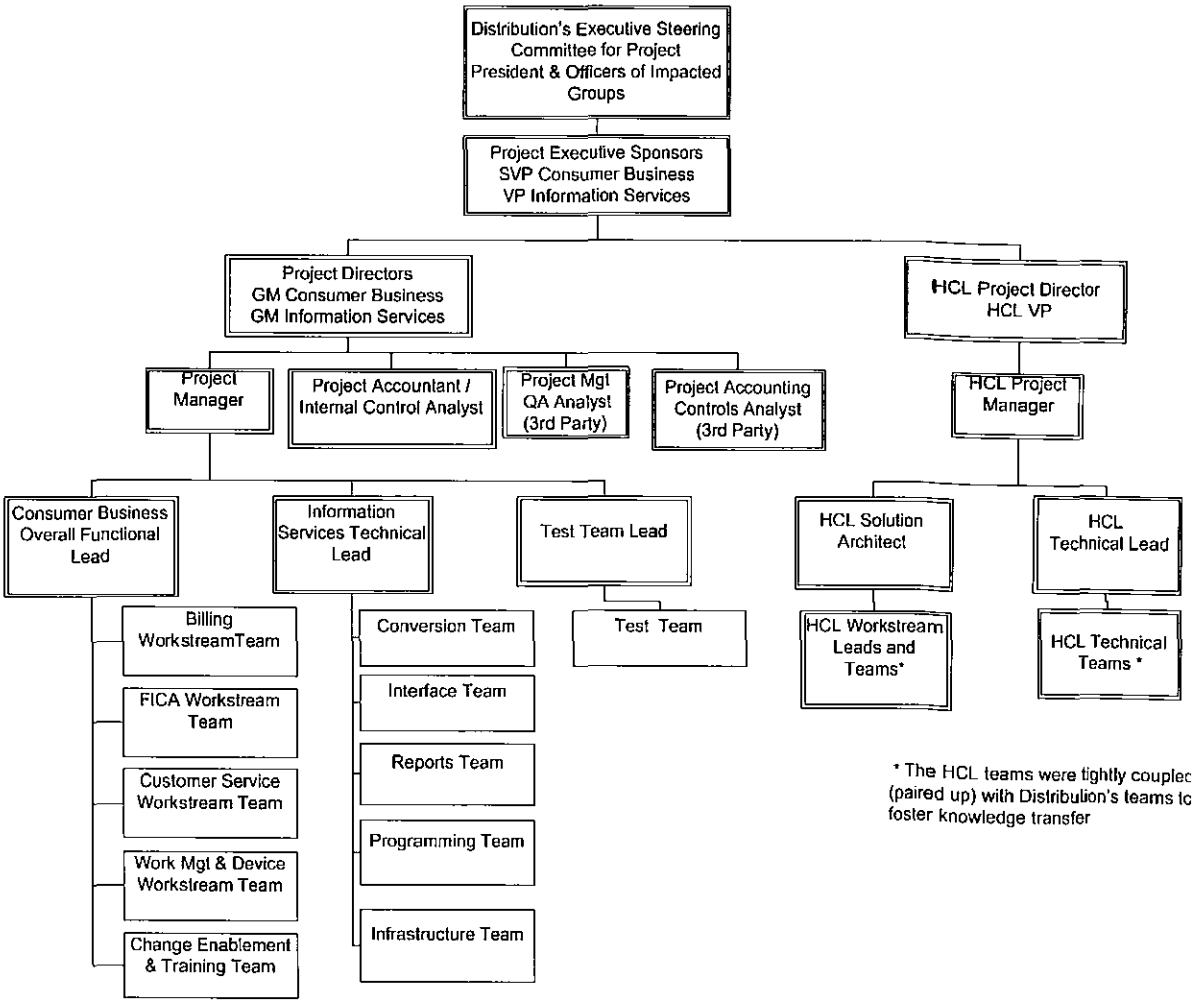

In addition, monthly executive steering committee meetings were held which addressed actual progress against planned progress, changes in project staffing, actual project costs against planned costs, successes and challenges, and any issues that needed executive input or intervention. As needed, day to day executive oversight was handled by the project's two executive sponsors, the

1 Senior VP of Consumer Business and the VP of Information
2 Technology. The two executive sponsors were kept informed and
3 stayed very close to issues and status throughput of the project.
4 Q. How did Distribution work with HCL?
5 A. Distribution's project directors, the GM of Consumer Business and
6 the GM of Information Services, worked closely with HCL's project
7 director to address any administrative and/or contractual issues.
8 Distribution's project directors acted as the connection between the
9 project managers and the two executive sponsors, adding
10 managerial guidance and resolving issues at their level when they
11 could, and bringing issues to the attention of the executive
12 sponsors for day to day assistance when necessary. The project
13 directors also coordinated and received feedback on project status
14 from TMG, Inc., the third party firm Distribution retained to conduct
15 monthly independent quality assurance reviews on the overall
16 project's progress. TMG has extensive experience in performing
17 QA on CIS implementations. Distribution wanted an independent
18 third party's view to identify issues as early as possible so that the
19 appropriate risk mitigation actions could occur to keep the project's
20 scope, timeline, and cost in line with expectations. These monthly

1 QA reports were passed up to the executives and down to the
2 project managers.
3 Q. Were any other third parties involved in the project management
4 and oversight?
5 A. Yes. The project directors also coordinated and received feedback
6 from PriceWaterhouseCoopers (PwC), which had been retained to
7 perform a pre/post-implementation assessment of the project's
8 controls. PwC was to assess the 'to be' design of internal controls
9 in a pre-implementation environment, as well as an operational
10 effectiveness assessment of controls in a post-implementation
11 environment. They focused on internal controls over financial
12 reporting and their associated control objectives, risks and financial
13 statement assertions. The project's accountant/internal control
14 analyst was previously a chief auditor of the Company and worked
15 closely with PwC to keep the project directors and the executive
16 sponsors informed about PwC's observations.
17 Q. Please describe how the management of the project was
18 conducted.
19 A. Day to day project management was carried out by the two project
20 managers, one from Distribution and one from HCL. These

1 managers continually monitored the project's status against
2 planned completion dates and either adjusted the scope or
3 resources to resolve problems, or consulted the project directors
4 when they were unable to affect the required changes. The primary
5 vehicle to keep the entire project team on track and to keep all
6 project stakeholders informed of the project's overall status was the
7 weekly PMO Status meeting. These weekly meetings typically ran
8 for ninety minutes, were attended by the project management team
9 from the project directors down, and included all of the work stream
10 and technical team leads from both Distribution and HCL. The
11 participants reviewed: graphs and statistics related to the specific
12 activities in progress at the time; any new challenges, issues, or
13 risks uncovered; staffing issues; upcoming communication and
14 training events; and overall project health from the viewpoints of the
15 PMO, the functional teams, the technical teams, and the change
16 enablement/training team.
17 The other major recurring weekly meeting, which began in
18 June 2014, included the Distribution and HCL project directors,
19 project managers, and the functional work stream leads were the
20 Software Scope Control (SCC) meetings. These meetings were

1 extremely important because they addressed proposed system
2 changes which had arisen after the majority of the technical
3 blueprint was completed. Regardless of the root cause of any
4 particular change, this weekly meeting was designed to determine:
5 • if a proposed change was really necessary;
6 • if there were other workarounds available negating the need for the
7 change; and
8 • if necessary, how it could be accomplished in the least impactful
9 way in terms of the project's schedule or risk profile.
10 Q. How were potential changes handled?
11 A. All potential changes were logged in the APSE tool and reviewed
12 by this group for final disposition. This group controlled the project
13 scope to ensure that any expansion from the original Statement of
14 Work was absolutely necessary.
15 Q. Please describe the other components of project management.
16 A. Several other periodically recurring meetings and status updates
17 occurred with the appropriate participants. These other recurring
18 meetings or updates included; training readiness, cut-over
19 readiness, internal process owners with interfaces to CIS
20 readiness, and monthly project budget reporting.

Conversion Risk Mitigation Activities: Mock Data Loads and Dress Rehearsals

Q. What types of conversion risk mitigation activities were conducted?

A. Both mock data loads and dress rehearsals were conducted.

Q. How were mock data loads conducted?

A. Distribution conducted six mock data loads between December 2014 and February 2016 which extracted all of the data out of the old CIS application, transformed it, and then loaded it into the new SAP CIS system. A typical mock data load took 2 days to run the extract processes, 2 days to transform and load the data into the new system, 1 day to perform manual data entry for things that were not converted by automation, and 1 day to verify that the data was properly loaded and that the financials were in balance. These mock data loads allowed Distribution to test and become comfortable with the project's data conversion processes.

Q. How were dress rehearsals conducted?

A. Five dress rehearsals were conducted between May 2015 and March 2016 to test the entire cut-over plan. Each dress rehearsal simulated shut-down of the production system and transition into the manual mode; all data conversion activities; and all manual pre- and post-conversion activities. Dress rehearsals also conducted

1 hourly checkpoint meetings throughout the multi-day cutover
2 process to ensure that all of the required activities occurred within
3 the projected timeframes; practiced the go/no go decision points
4 along the cutover plan. Post-mortems were held after the dress
5 rehearsal to identify areas for improvement. These dress
6 rehearsals allowed Distribution to test and become comfortable with
7 the entire cutover process.

8 **Risk Mitigation for Maintaining Customer Service Levels Immediately**
9 **After Project Implementation**

10 Q. Please discuss the reasons for the additional risk mitigation
11 measures immediately after project implementation.
12 A. In several of Distribution's reference checking discussions with
13 companies who had recently implemented new CIS applications,
14 we were advised not to underestimate the learning curve needed
15 for employees to become proficient on the new system.
16 Companies told Distribution that they either had or should have
17 increased their phone center and back office staffs by 20-40 % to
18 offset the backups they experienced due to learning curves and lost
19 productivity. Each of these companies said they had done
20 employee training as an integral aspect of their projects. They
21 stated that it was unrealistic to expect the pre-implementation levels

of productivity no matter how thorough the training was. A few of these companies experienced significant customer service issues spanning multiple months as a result of not increasing their staffing levels to offset this challenge.

Q. What risk mitigation measures did the Company take?

A. Distribution increased its phone center staffing in anticipation of this loss in productivity due to the learning curve.

Original Estimated Costs to Implement the New System (as of Fall 2013)

Q. How did Distribution develop its estimated implementation costs for the project?

A. Distribution gathered as much publicly available industry cost information on CIS replacements as it could find in late 2011 and 2012. Those figures were very generalized and varied significantly. Once Distribution had received the RFP responses, it developed a bottom-up cost estimate to implement the new system in the fall of 2013 based on the following cost categories (dollars in millions):

DIRECT TESTIMONY OF PATRICK T. BOYLE

		November 2013		
Category	**Description**	**NY Capital**	**NY O&M**	**NY Total**
Outside Consulting Services	CIS Selection/Procurement Firm (Five Point Partners), Systems Integration Firm (HCL), Legal Firm (Jones day), Quality Assurance Firm (TMG), Public Accounting Controls Review Firm (PwC), Contract Programmer/Developers (various local firms Distribution utilizes).	$ 22.8	$ 3.6	$ 26.4
Software and Maintenance	All software acquired to implement the new system; primarily software from SAP, Oracle (database), and ESRI (GIS software).	$ 9.1	$ .7	$ 9.8
Computer Hardware	All additional hardware required to implement the new system; primarily Dell servers, and IBM storage.	$ 3.0	$ 0	$ 3.0
Incremental Employees Hired for the Project	Incremental hires brought into Distribution and placed directly onto the project team.	$ 1.6	$ 0	$ 1.6
Project Pay	Funds used to compensate the project team members who live in PA and had to spend four days a week in NY away from their families and personal lives.	$ .2	$ 0	$ .2
Project Office	Dedicated project office space (rent), cleaning, utilities, etc.	$ .3	$ .3	$ .6
Employee Travel & Expenses	Hotels, food, and mileage costs for employees on the project.	$ .3	$ 0	$ .3
Office Employee Expense	Predominantly employee training and other miscellaneous O&M expenses.	$ 0	$ .4	$ .4
Management Reserve	Contingency Funds in the Event Unforeseen Expenses Arise	$ 1.8	$ 0	$ 1.8
	Totals	$ 39.1	$ 5.0	$ 44.1

1

1 Q. Please explain the figures in the table above.

2 A. The figures above represent 71% of the project's total costs.
3 Distribution used a standard allocation of 71% to New York and
4 29% to Pennsylvania for all project costs based on customer counts
5 across the two states. All of the capital figures above, with the
6 exception of computer hardware, have AFUDC built into them.

7 **Current Estimated Costs to Implement the New System (as of Spring**
8 **2016)**

9 Q. What are the current estimated costs to implement the new CIS
10 system?

11 A. The chart below sets forth the current estimates.

12

DIRECT TESTIMONY OF PATRICK T. BOYLE

		January 2016				
Category	**Reason For Cost Change**	**Change In NY Capital**	**Revised NY Capital**	**Change in NY O&M**	**Revised NY O&M**	**Revised NY Total**
Outside Consulting Services	1) At the conclusion of the project's design phase (Fall 2014) Distribution agreed to a $ 1 Million HCL change order as a result of additional project scope and associated work discovered during that phase. 2) The project's ten month extension (July 2015 to May 2016) adds AFUDC. 3) At present with the 10 months extension, HCL has been advocating for a change order in the $ 7 Million dollar range.	$ + 6.9	$ 29.7	$ - .1	$ 3.5	$ 33.2
Software and Maintenance	10 month extension of project has caused additional software maintenance costs to hit the project.	$ + 1.6	$ 10.7	$ - .3	$ .5	$ 11.2
Computer Hardware	Actual pricing for hardware came in significantly under the budgeted amounts.	$ - 1.1	$ 1.9		$ 0	$ 1.9
Incremental Employees Hired for the Project	10 month extension of project.	$ + 1.0	$ 2.6		$ 0	$ 2.6
Project Pay			$ .2		$ 0	$ .2
Project Office	10 month extension of project.	$ + .2	$ .5	$ - .1	$ .2	$ .7
Employee Travel & Expenses			$ .3		$ 0	$ .3
Office Employee Expense			$ 0		$ .4	$ .4
Management Reserve	As designed, used to offset other increases.	$ -1.8	$ 0		$ 0	$ 0
	Totals	$ + 6.8	$ 45.9	$ -.4	$ 4.6	$ 50.5

1 **Estimated Operating Costs for New System**

2 Q. Please describe Distribution's estimated operating expenses for the
3 project.

4 A. In addition to the project's depreciation expense, Distribution has
5 incremental annual software maintenance fees for the SAP
6 application software; the Oracle database management system;
7 and the Geographic Information System software required for
8 service order dispatching. The new CIS application has several
9 diverse technology stacks within it which execute on approximately
10 one hundred and forty servers to support the required environments
11 (high availability production, quality assurance, development,
12 training, etc.). The amount of physical data storage the new
13 system requires is approximately forty times (40 TB vs. 1TB, TB=
14 Terabyte) that of the old mainframe-based system. As a result of
15 this much larger technology footprint, the incremental costs for the
16 disaster recovery services to ensure system availability are
17 significantly increased. Finally, due to the much larger technology
18 footprint, the Information Technology (IT) support staff required to
19 maintain the new CIS is ten FTEs larger.

20 Q. What are the incremental annual operating expenses for the

1 project?

2 A. Please see below.

3 Depreciation Expense *	$ 4,600,000
4 Software Maintenance Fees **	1,750,000
5 Disaster Recovery Services	386,000
6 IT Support Analysts (10 FTEs) ***	900,000
7 Total	$ 7,636,000

8 * Total project's capital cost depreciated over ten years as

9 included in the Exhibits of J. J. Spanos

10 ** These annual fees will increase slightly over time

11 *** Based on 2016 estimate for fully loaded FTEs with salary and

12 benefits and included in Exhibits of R. M. Friedrich-Alf.

13 Q. Will the replacement of the new CIS result in cost avoidance?

14 A. While replacement of Distribution's current CIS will remove

15 approximately 80% of the utilization on its current IBM mainframe

16 environment, no cost avoidance will be recognized there until the

17 other remaining 20% of applications are also replaced and the

18 mainframe can be retired. Due to the complexity of replacing these

19 remaining 20% of applications, the Company anticipates that the

20 legacy mainframe will continue to be in service until after 3/31/18.

1 **Project Challenges Causing Implementation Date Changes**

2 Q. Has the implementation date for the project been postponed?

3 A. Yes. Distribution changed the system's planned implementation
4 date twice: 1) from the original date of July 2015 to October 2015;
5 and 2) most recently from October 2015 to May 2016. The two
6 most critical considerations in determining whether the system was
7 ready for implementation were: 1) ensuring that all required system
8 functionality was in place, enabling Company employees to
9 properly service customers in an effective and timely manner
10 (solution breath); and 2) ensuring that all system components were
11 working as designed (solution accuracy and stability).

12 Q. Please describe some of the challenges that have delayed the
13 implementation date.

14 A. The actual amount of custom development work required to support
15 Distribution's business processes was significantly higher than what
16 the system integrator (HCL) had estimated. While Distribution
17 attempted wherever possible to use delivered SAP functionality to
18 meet the business requirements outlined in the project's RFP, HCL
19 under-estimated the number of custom developed forms, reports,
20 interfaces, conversions, enhancements, and workflows (FRICE-W

1 objects) needed. All of these custom objects required design,
2 construction, testing, and integration into the SAP solution which
3 increased the overall size and complexity of the project.
4 In addition, HCL experienced staff turnover and issues with
5 team leaders during the critical design phase of the project on two
6 teams. The Financial Contracts and Accounting team (FICA) and
7 the Intercompany Data Exchange team (IDEX) had issues requiring
8 changes in HCL team leaders which caused design rework in both
9 areas. Approximately 40% of all custom development work was in
10 the FICA area.
11 Q. Were there any other challenges which postponed implementation?
12 A. Yes. As Distribution realized it could not complete all of the
13 required custom development work, the team reviewed whether
14 some of it could be deferred until after go live. Some custom
15 objects were needed for processes that are only needed in the fall
16 or winter, meaning that with the original scheduled go live date in
17 July, those objects could potentially be deferred until three or four
18 months after the planned go live date. However, after determining
19 what would need to be deferred to achieve the July go live date,
20 and then evaluating if that "potentially deferred work" could be

1 completed in the three or four months after go live, the Company
2 determined that the probability of not getting that deferred work
3 done by the time it was needed was very high. Therefore, since
4 going live without the "yet to be completed" custom objects would
5 impair Distribution's ability to service customers (incomplete
6 solution delivery), the Company determined that the prudent
7 approach would be to move out the go live date to ensure no
8 disruption to the reliability of its service.
9 Q. Were there additional reasons why the customer development
10 work delayed implementation?
11 A. Yes. The project plan called for first completing all custom
12 development work (the FRICE-W build) prior to beginning
13 integration and user acceptance testing. Due to the fact that the
14 project team was behind schedule in completing the custom objects
15 because the effort had been underestimated, the project began to
16 overlap the integration test phase before all of the development
17 was completed. It became apparent that the risk of overlapping
18 development and testing was not prudent. Some custom objects
19 coming out of development were adversely impacting areas that
20 had already been tested, causing the need for retesting to ensure

1 accuracy and stability. As a result of this, in the fall of 2015 the
2 entire project team was refocused almost exclusively on completing
3 the custom development objects so that in February 2016, the team
4 would refocus on testing, training, and go live readiness with the
5 development work behind them. In doing this, the team was able to
6 complete almost all of the custom objects by mid-February.
7 However, during this period other project activities (e.g., integration
8 testing, user training, internal readiness assessment, testing with
9 impacted external parties, such as payment agents, collection
10 agencies, government agencies, etc.) were suspended. All of
11 these suspended activities had to be restarted and some required
12 redoing (testing) or rework (development of training materials) as a
13 result of changes which came out of the custom development.
14 Q. Did user training also necessitate postponement of the
15 implementation date?
16 A. Yes. A significant amount of user training had been conducted
17 leading up to the planned July and October 2015 implementation
18 dates. Given the time span between when that training was
19 received by employees, mostly between May and September of
20 2015, and the new date of May 2016 (nine months later),

1 incremental refresher training for all employees was required to
2 ensure they had retained the training.
3 Q. Please describe how the system's stability was measured.
4 A. Distribution established a separate testing team to have an
5 objective group of business users evaluating the system's stability
6 and readiness for production. Formal test cases and test scripts
7 were developed and a defect logging and tracking mechanism was
8 used to manage and document all defects uncovered. Monitoring
9 these defect statistics enabled project management to evaluate the
10 system's accuracy, stability, and go live readiness. Leading up to
11 the go / no-go decisions for the two missed go live dates,
12 evaluation of the number, severity, and status of project defects
13 was invaluable. Leading up to the July and October dates, the
14 Company determined that the number of open "critical" and "high"
15 defects was unacceptable. It was a reasonable and prudent
16 decision to postpone the go live date given these circumstances.
17 Q. How is a "critical" defect defined?
18 A. Critical (Severity One) means a Defect in the System which causes
19 a material business impact including, for example (without
20 limitation), loss or material degradation of billing functionality or

1 accuracy, major customer or company data corruption, major
2 customer disruption, or serious financial impact or damages.
3 Q. How is a "high" defect defined?
4 A. High (Severity Two) means a Defect in the System which causes a
5 material business impact described in Severity One, but where an
6 automated or manual workaround is acceptable to the company to
7 minimize the issue while the defect exists. The workaround is
8 short-term only for an accepted amount of time by the company
9 until fixed or it will become a Severity Level One.
10 Q. Is Distribution cautious about implementing the system before it is
11 deemed to be ready?
12 A. Yes. As driven as everyone within Distribution's project team has
13 been to implement this large and complex project on time and on
14 budget, it has always been understood that the system would not
15 be implemented if it is not ready. The potential negative
16 consequences for our customers were too great. The system must
17 deliver the required functionality needed for employees to properly
18 service customers in an effective and timely manner, provide
19 accurate information in all cases, and be stable (up and
20 operational) and reliable. The implementation date changes were

1 management's decision that the system was not ready for

2 implementation at those points.

3 Q. Does this conclude your testimony?

4 A. Yes, at this time.

Q. Please state your name and business address.

A. My name is Patrick T. Boyle and my business address is 6363 Main Street, Williamsville, New York 14221.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I previously submitted direct testimony on behalf of National Fuel Gas Distribution Corporation ("Distribution" or the "Company").

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address issues raised by Mr. Haslinger of the New York Department of Public Service Staff ("Staff"), the Staff Policy Panel and Mr. Collar of the Utility Intervention Unit ("UIU") of the New York State Department of State's Division of Consumer Protection, related to the timing of potential benefits and efficiency improvements as a result of implementing the new Customer Information System ("CIS") and Mobile Workforce Management ("MWM") solutions in May 2016. Specifically, I will address their collective recommendation to impose an additional one percent productivity adjustment over the so-called "standard" one percent productivity disallowance imposed by the New York Public Service Commission ("Commission") due to the implementation of these systems. Nothing in my testimony herein, however, should be taken as a concession that the so-

called standard one percent productivity disallowance is appropriate or warranted in this proceeding.

Q. Please summarize your rebuttal testimony.

A. The Company had taken every reasonable step it could to extend the life of its legacy CIS and MWM systems, which have been in use for just shy of twenty-six years. The new system replacement was born of necessity due to:

- the inability to make system modifications in a timely or cost effective manner - a symptom of impending obsolescence of the legacy systems
- the avoidance of future uncontrollable support costs for the legacy systems

While all of the potential benefits noted in my initial testimony and cited by Mr. Haslinger and Mr. Collar could theoretically be achieved in the future, there are two key issues which must be considered when evaluating any potential financial benefits associated with the CIS and MWM solutions:

- timing - when those potential benefits might, if at all, be reasonably achieved

- the net impact of any cost savings associated with those benefits versus the incrementally higher Information Technology ("IT") operating costs of the new system.

The Company will not even begin to realize some of those benefits until at least three years after implementation of the CIS on May 9, 2016. Three years after May 9, 2016 is May 9, 2019, well after the Rate Year ends on March 31, 2018. Moreover, whether any potential benefits will accrue at all is unknown and the Company is already experiencing the higher incremental IT operating costs. My rebuttal testimony will explain: why those potential benefits are at least three years out, why the Company is already experiencing the incremental higher IT operating costs, and why an additional one percent productivity adjustment based on the system's implementation is wholly inappropriate.

Q. Did the Company base its decision to replace the CIS and MWM systems on future benefits or cost savings promised by a new system?

A. No. The Company's decision to replace its' legacy CIS and MWM was primarily a risk mitigation activity due to the impending obsolescence of those legacy systems. Those systems were designed and developed in the late 1980's, implemented in 1990,

and had been in use for twenty-two years when the Company's replacement decision was made. It was also known at that time that a replacement project would take two to three years to complete, so when the Company made the decision to replace in 2013, the May 2016 implementation of the new system put the legacy system at just shy of twenty-six years in service. The legacy system needed to be replaced for all of the reasons outlined in my original testimony namely, 1) the cumulative impact of thousands of system changes to the legacy systems over the past twenty-two years; 2) legacy technology issues; 3) an outdated/restrictive data model; 4) the obsolescence of paper-based workflow; 5) the inability to obtain customer data for analysis in a timely manner; 6) the inability to find the IT skillsets required to maintain the legacy system; and 7) reduced leverage in negotiating future software annual maintenance fees.

Q. What were the primary risk factors driving the decision to replace the CIS and MWM systems?

A. The primary risks were:

- The potential to introduce unintended consequences when making system changes due to the legacy system's underlying complexity and fragility due to over two decades

of programming changes modifying and extending the original design to meet changing business and regulatory requirements.

- An inability to implement required enhancements or changes in a timely or cost acceptable manner due to the legacy system's underlying foundational 1990's "premise-based" data structure.
- An inability to reliably interface today's technologies with the 1990s technologies underpinning the legacy systems.
- The inability to find and retain IT employees willing to work on legacy mainframe computer technologies.

Q. What future uncontrollable costs will be avoided by replacing the legacy CIS and MWM systems?

A. If the Company had stayed with the legacy system, it would have had to re-negotiate a new annual maintenance contract with Software AG of North America (the Company’s current agreement ends in August of 2017), as all of the underlying technology supporting the legacy system is theirs. The Company's annual maintenance contract with Software AG represents the largest cost mainframe software maintenance contract. The Company would have had extremely limited leverage in that negotiation, because

Software AG is the sole provider and the risk of not carrying the annual maintenance would have been far too great. It is my opinion that, based on personal past contract negotiations with Software AG, the Company's annual software maintenance increase would have been in the 50-100% range.

Q. Does the Company expect to experience savings and/or benefits within the first several years of implementing the new CIS and MWM system?

A. No. It has always been the Company's expectation based on my previous first-hand experience in implementing the Company's legacy CIS in 1990, the Enterprise Resource Planning Financial systems in 2001, and discussions with professional colleagues over the past twenty-five years who have implemented CIS systems that:

- Immediately following implementation, the Company would spend at least one year "stabilizing" the new system (introducing many small changes to correct problems), resolving issues, and learning to operate the "delivered" system effectively. During that period, we expected the Company’s IT support group to spend

almost all of their time resolving issues, and dealing with only mandatory regulatory changes.

- After this period, the Company's IT support group and the users of the new system will gain experience ("learning the new system") and begin to more fully appreciate how the system operates in a production environment. This period of learning is expected to last for approximately two years, after which the Company's IT support team and system users may begin to propose changes to increase the system's usability and possible efficiencies based on their actual experience.
- After this period of "learning" on a stable system, the Company can then evaluate proposed changes, assess how to best architect (determine how to implement system changes or procedural changes, or both), and then actually implement these changes over the ensuing years.

The Company is currently experiencing a loss in productivity on the new system relative to the legacy system. Part of that loss is learning curve, however, a significant part of that loss is the fact that the legacy system was designed and optimized for the

Company's business practices (and tariff) while the new system is a generic SAP design meant to be able to support any utility. While the Company believes that in the long run, efficiencies may be achieved, until we go through the first two phases of "stabilization" and "learning", and then "optimize" the way we use the new system, we will not know exactly when we may see efficiency improvements. But, we do know already (after operating the new system for three months), that it will take several years to realize actual productivity improvements and potential cost savings. This is further proof that this replacement project was never about benefits and/or cost savings, rather it was about the Company's risk mitigation and positioning the Company to serve our customers in the future.

Q. What other significant factors will impact the Company's ability to achieve benefits, efficiencies, and cost savings in the near term?

A. There are three additional, significant factors: (1) the magnitude of changes (learning and unlearning) impacting each individual employee, (2) a freeze on CIS/MWM enhancements during the new system's development, and (3) the fact that the Company is unable to shed any of its' existing mainframe computer expenses until at least early 2019.

Magnitude of Changes: These two systems are used on a daily basis by all Company employees who have any interaction or responsibilities related to customers and on a less frequent basis by almost all of the rest of the employees of the organization. Implementation of these systems introduced a magnitude of change in tools (interfacing with the new computer system itself) and processes (the business procedures for how to accomplish the work) that the Company has not experienced since the legacy system was implemented in 1990. Also, the CIS implemented in 1990 was less complex, since New York had not yet gone through the Commission's deregulation of the late 1990's, resulting in marketer aggregation and the significant increase in low income programs over the past ten years. Getting employees to learn, accept, and become proficient with changes of this magnitude takes years.

Freeze on CIS/MWM Enhancements during Development: During any large computer system replacement project, it is absolutely necessary to establish a date when the system's design (or blueprint) is signed off and frozen. Much like building a structure, once the blueprints are finalized, the plan is frozen and construction

begins - otherwise cost overruns, redos, and a project that never gets completed are the result. In order to keep this project on schedule and on budget, the blueprints were frozen over two years ago. All requests for changes and enhancements that came in after that date were put into a holding queue by the Company for review and evaluation once the new system had been stabilized. Even though the Company froze the design in 2014, and used that design as the basis for the system that went live this past May, the real world continued forward and requests for changes have queued up. Basically, the Company has a two year "backlog" of requests for changes to CIS and MWM which must now be reviewed and dealt with. The changes in this backlog deemed necessary or worthy to be implemented will be addressed, however, the Company still has to "catch up" on a two year backlog, which will take at least a couple of years, after the system is stabilized.

Inability to Shed Existing Mainframe Computer Expenses: The mainframe hardware and software which the legacy CIS system was (and is) running on are still in place. The Company has other non-CIS mission critical applications still running on that mainframe platform using the same underlying software and disaster recovery

services that legacy CIS was using. These non-CIS mission critical applications must continue to operate on that system until a viable replacement is available, and it was not practical for the Company to transition these non-CIS mission critical applications off the mainframe at the time of the CIS replacement. The mainframe is a single shared resource (hardware and software) which the Company has leveraged extensively over the past three decades to share across legacy CIS and the other mission critical mainframe applications. The Company is still running its legacy CIS on-line in "inquiry-mode" because;: (1) it has six years of customer history going back from May of 2016 – the Company did not convert back that many months in the new SAP system, (2) we still need it as a reference/safety net to check converted data against if we were to uncover any data abnormalities as we move ahead with the new application, and (3) the remaining mission critical non-CIS mainframe applications were integrated into the legacy CIS and we are back-feeding sections of legacy CIS to support those applications until they are replaced, after which the Company will decommission the mainframe and stop incurring mainframe hardware and software costs. Current plans are to replace the remaining non-CIS mainframe applications by the end of 2018. We

would then expect to leave the mainframe up and running in "view-only mode" for approximately six-months after that as a reference source in case issues come up in the new applications and we need to check data or processes to help resolve issues. We are targeting actually taking the mainframe off-line (decommissioning) in 2019.

Q. Why does the electronic workflow implemented with the CIS system not return efficiencies and cost savings in the near term?

A. The electronic workflow in the new system does increase the speed with which employees' work can be assigned, monitored, and re-assigned if necessary. However, the new system is much more rigid (unforgiving) than the legacy system was, generating many more meter reading and billing exceptions (the work being electronically routed in workflow) than the legacy system ever did. So while the electronic workflow is much more efficient in providing a tool to manage the work, the new system is generating a significantly higher quantity of work, which is more than offsetting the gains from the electronic workflow itself.

Q. Why does the increased flexibility of the new system not translate into cost savings and benefits in the near term?

A. A core component of replacing our legacy CIS was to ensure that when future opportunities or regulatory mandates requiring significant system changes occur, we could respond in a timely and effective manner. The Company had stretched the useful life of our legacy CIS to its' limit. Initiatives such as the Commission's *Reforming the Energy Vision* ("REV") would be extremely difficult and technologically challenging to implement in both a cost-effective and timely manner based on the 1990's technology under the legacy system. The new system positions the Company with a solid foundation to address these types of situations going forward. Potential future "cost avoidance" is a much better descriptor for the flexibility that this new system will provide.

Q. Why does the improved system maintenance not translate into cost savings and benefits in the near term?

A. As evidenced in my responses to Staff interrogatory DPS Set 10 #84 (Attached as Exhibit_PTB-1), the Company's IT support group required to support the new system is 50% larger than the IT support group required to support the legacy system. The IT support organization was 20 FTEs for the legacy system and is now 30 FTEs for the new system. The new system is more complex and larger, requiring a larger support staff. It has a greater variety

of underlying software (various SAP and partner products) to maintain. So, while the Company's IT support group may in the future become more efficient in implementing individual changes and/or system maintenance, those efficiencies (cost savings) are more than offset by having to maintain a significantly larger and more complex system. This characteristic of being much larger and complex, and, therefore, more expensive to maintain than 1990's era legacy CIS applications, is true for both of the two leaders in commercially available utility CIS applications (SAP and Oracle).

Q. Why doesn't the availability of more competitive software maintenance fees and increased choices for consulting services translate into cost savings in the near term?

A. The availability of options in acquiring software maintenance on the new system and in having more firms to hire for professional services to enhance the new system will not produce savings but it will help the Company contain future cost increases as the system is enhanced and extended. More vendors (competing for Company business) creates a more competitive market for the Company's business. Having more choices allows the Company to shop, and obtain the best price/value alternatives, which will help us to control

our costs, which in turn will allow us to keep overall operating costs reasonable for our customers in the future.

Q. Why doesn't the increased productivity of new hires translate into cost savings in the near term?

A. As evidenced in my responses to Staff interrogatory DPS Set 10 #84 (Attached as Exhibit_PTB-1), the Company IT support group required to support the new system is 50% larger than the Company IT support group required to support the legacy system. This is due to the new system being much more complex and larger, with a greater variety of underlying software systems to maintain. New hires, frequently coming out of college, should be more familiar with the technology and become more productive on the new system sooner because it is more similar to what they may have learned in school. So, while the Company's IT support group of new hires should be much more efficient in implementing individual changes and/or system maintenance, those efficiencies (cost savings) are offset by having to maintain a significantly larger and more complex system.

Q. What is your conclusion?

A. I conclude that there is no basis for Staff to propose, or the Commission to adopt, the additional one percent productivity factor

based on expected Rate Year efficiencies and benefits due to the implementation of CIS and MWM systems because there simply are none in the near term. The CIS system was not installed and implemented to produce cost savings. It was necessary because the legacy CIS had long outlived its usefulness. This is unsurprising as most technology applications are obsolete in a decade. Not only was the legacy system obsolete but it was incapable of providing many of the customer service features now demanded by today's customers. Having demonstrated that cost savings was not the driver of replacement, we are, nevertheless, of the belief that our CIS will enable our employees to deliver service in a more efficient manner following the stabilization and harmonization of the system several years in the future. That, said, however, the evidence is clear, as both Company witness Donald Parr and I demonstrate, that any imputation of additional productivity in the Rate Year is unwarranted and unsupported by both Distribution's experience and that of the industry, generally. For that reason, Staff's and UIU's imputation of additional productivity of one percent in the Rate Year for the CIS is simply inappropriate.

Q. Does this complete your rebuttal testimony?

A. Yes, at this time.

A.L.J. LECAKES: Are there any exhibits attached to the Boyle testimonies?

MR. NICKSON: There is one exhibit attached to the rebuttal testimony of Mr. Boyle. That was identified as PTV-1 and I would ask that it would be marked for identification.

A.L.J. LECAKES: I'll mark it as Exhibit 9. The next affidavit?

MR. NICKSON: Next, I would like to offer the testimony and exhibits of Ms. Ann E. Bulkley. For the record, Ms. Bulkley prepared testimony entitled Direct Testimony of Ann E. Bulkley which consists of a cover page, a table of contents, and 91 pages of questions and answers and two appendices. Ms. Bulkley also prepared testimony entitled The Rebuttal Testimony of Ann E. Bulkley which consists of a cover page, a table of contents and 88 pages of questions and answers. Ms. Bulkley also prepared supplemental testimony entitled The Supplemental Testimony of Ann E. Bulkley which consists of three pages of questions and answers. I would ask that the direct rebuttal and supplemental testimony of Ms. Bulkley be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. At this point in the record, the Bulkley Direct Testimony file should be put in, the Bulkley Rebuttal Testimony and -- I don't have it open. Is it Bulkley Supplemental Testimony? Is that what it's called?

MR. NICKSON: That's correct. Yes.

A.L.J. LECAKES: Okay. That should be next.

Before the New York State Public Service Commission

National Fuel Gas Distribution Corporation

DIRECT TESTIMONY OF
ANN E. BULKLEY

(VICE PRESIDENT OF
CONCENTRIC ENERGY ADVISORS, INC.)

Dated: April 8, 2016

Testimony of Ann E. Bulkley

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A. My name is Ann E. Bulkley. I am a Vice President of Concentric Energy Advisors, Inc. ("Concentric"), located at 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting this Direct Testimony on behalf of National Fuel Gas Distribution Corporation ("Distribution" or the "Company"), the utility operating subsidiary of National Fuel Gas Company ("NFG"). My Direct Testimony is part of the Company's rate case filing before the New York State Public Service Commission ("PSC" or "Commission").

Q. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I have approximately 20 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my resume and a summary of testimony that I have filed in other proceedings as Attachment A.

1 **Q. PLEASE DESCRIBE CONCENTRIC'S ACTIVITIES IN ENERGY AND UTILITY**
2 **ENGAGEMENTS.**
3 A. Concentric provides regulatory, financial, and economic advisory services to a
4 large number of energy and utility clients across North America. Our regulatory,
5 economic, and market analysis services include: utility ratemaking and regulatory
6 advisory services; energy market assessments; market entry and exit analysis;
7 corporate and business unit strategy development; and energy contract negotiations.
8 Our financial advisory activities include: merger, acquisition, and divestiture
9 assignments; due diligence and valuation assignments; project and corporate
10 finance services; and transaction support services. In addition, we provide litigation
11 support services on a wide range of financial and economic issues for clients
12 throughout North America.

II. PURPOSE AND OVERVIEW OF TESTIMONY

13 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**
14 A. The purpose of my Direct Testimony is to present evidence and provide a
15 recommended range for the Company's cost of equity (sometimes referred to as the
16 "Return on Equity" or "ROE" for rate-setting purposes) and capital structure for
17 Distribution, the utility operating subsidiary of NFG, as a stand-alone entity. The
18 ROE recommendation that is presented in my Direct Testimony meets the capital
19 attraction standards established in *Hope* and *Bluefield* for Distribution on a stand-

alone basis. As such, the proxy group that is discussed in Section __ of my Direct Testimony is comparable to the risk profile of Distribution, the natural gas distribution utility that operates in the State of New York, not NFG, the parent company. My analysis and recommendations are supported by the detailed data presented in Exhibits __ (AEB-1) through __ (AEB-16).

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT LED TO YOUR ROE RECOMMENDATION.

A. As discussed in more detail in the remainder of my Direct Testimony, it is important to consider the results of several analytical approaches in determining a reasonable recommendation for the Company's ROE. To develop my ROE recommendation, I considered two proxy groups – the Natural Gas Utility Proxy Group, which consists entirely of natural gas distribution companies, recognizing that the Company is a natural gas distribution company and a Combined Utility Proxy Group that consists of companies that face risk generally comparable to that faced by the Company. The Combined Utility Proxy Group includes both electric utilities and natural gas distribution utilities. I developed a multi-stage Discounted Cash Flow ("DCF") model and two forms of the Capital Asset Pricing Model ("CAPM"). I weighted the results of the two CAPM analyses equally, and then, for an overall recommendation, weighted the averaged CAPM result and the DCF analysis equally. I have considered the range of results established using both the Natural Gas Proxy Group and the Combined Utility Proxy Group because the Natural Gas

Proxy Group, although limited in size, may be more risk comparable to the Company than the Combined Utility Proxy Group.

The use of a multi-stage DCF model and two forms of the CAPM is consistent with the approach employed by the Commission in prior cases. While my determination to afford equal weighting of the DCF and CAPM results does not conform to the weighting typically employed in proceedings before the PSC in the past, I explain in this Direct Testimony why placing less emphasis on the DCF model at this time is actually more consistent with the goals of the Recommended Decision issued in the Commission's Generic Finance Proceeding, Case 91-M-0509, which has been relied on by the Commission to establish the ROE formula.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ROE ESTIMATION MODELS THAT YOU CONSIDERED IN YOUR ANALYSES.

A. The results of my analyses are summarized in Table 1 for both proxy groups.

Table 1: Summary of Analytical Results

Natural Gas Proxy Group			
	Low	**Mean**	**High**
DCF	8.77%	9.02%	9.37%
Mean CAPM	10.52%	10.72%	10.98%
Mean ROE (50/50 weighting)	9.65%	9.87%	10.18%
Combined Utility Proxy Group			
	Low	**Mean**	**High**
DCF	9.12%	9.30%	9.55%
Mean CAPM	10.38%	10.59%	10.85%
Mean ROE (50/50 weighting)	9.75%	9.94%	10.20%

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE COST OF EQUITY FOR THE COMPANY?

A. Based on the quantitative and qualitative analyses discussed throughout my Direct Testimony and the equal weighting of the DCF and CAPM results presented in Table 1, and based on my assessment of Distribution's business and financial risk relative to the proxy groups, I conclude that the appropriate ROE for the Company is within the range of 9.65 percent and 10.20 percent.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE APPROPRIATE RATEMAKING CAPITAL STRUCTURE FOR THE COMPANY.

A. The analysis presented in Section VIII of my Direct Testimony demonstrates that the Company's requested equity ratio of 48 percent is at the low end of the range of the authorized ratemaking equity ratios and actual equity ratios of the companies

in my proxy groups. Therefore, I conclude that the Company's Distribution's requested equity ratio is conservative.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

A. The remainder of my Direct Testimony is organized as follows:

Section III –	Discusses the regulatory guidelines and financial considerations pertinent to the development of the Cost of Capital;
Section IV –	Briefly discusses the current capital market conditions and the effect of those conditions on the Company's cost of equity;
Section V –	Explains my selection of the proxy groups of electric and gas distribution utilities used to develop my analytical results;
Section VI –	Explains my analyses and the analytical bases for my ROE recommendation;
Section VII–	Summarizes the specific regulatory and business risks that have a direct bearing on the Company's cost of equity;
Section VIII –	Provides an analysis of the capital structures of the proxy companies and forms the basis for my recommended capital structure; and
Section IX –	Summarizes my conclusions and recommendations.

III. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS

1 **Q. PLEASE DESCRIBE THE GUIDING PRINCIPLES TO BE USED IN ESTABLISHING THE**
2 **COST OF CAPITAL FOR A REGULATED UTILITY.**

3 A. The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases
4 established the standards for determining the reasonableness of a utility's allowed
5 ROE. Among the standards established by the Court in those cases are: (1)
6 consistency with the returns on equity investments in other businesses having
7 similar or comparable risks; (2) adequacy of the return to support credit quality and
8 access to capital; and (3) that the methodology used to arrive at a fair return is not
9 controlling, only that the end result leads to just and reasonable rates.[1]
10 Based on those standards, the Commission's order in this case should provide the
11 Company with the opportunity to earn a ROE that is (1) adequate to attract capital
12 at reasonable terms, thereby enabling it to continue to provide safe, reliable service;
13 (2) sufficient to support the financial soundness of the Company's operations; and
14 (3) commensurate with returns on equity investments in enterprises having
15 comparable risks. The authorized ROE should enable the Company to finance
16 capital expenditures at reasonable rates and maintain its financial flexibility over

[1] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

1 the period during which rates are expected to remain in effect.

2 **Q. HAS THE COMMISSION CONDUCTED A PROCEEDING TO REVIEW THE STANDARD**
3 **FOR ESTIMATING THE COST OF CAPITAL FOR A REGULATED UTILITY?**

4 A. Yes. On August 21, 1991, the PSC issued an Order establishing a proceeding
5 commonly referred to as the Generic Finance Proceeding ("GFP") to review the
6 PSC's then-current methodology for estimating the cost of equity and to examine
7 various alternatives.[2]

8 **Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE PURPOSE OF THE GFP.**

9 A. The GFP was initiated because the Commission recognized that the DCF method
10 was particularly sensitive to interest rate fluctuations and was producing returns far
11 below the returns produced by other methodologies.[3] The Commission's goal in
12 opening the GFP was to eliminate controversy around ROE calculations and
13 attempt to find common ground on contentious issues by developing a consensus
14 approach for setting utility equity returns. The Commission examined whether
15 there should be greater consistency in rate of return determinations from company
16 to company, such that differences in authorized returns could be directly attributed
17 to differences in risk between companies. In addition, the Commission examined
18 whether its historical primary reliance on DCF-based ROE determinations

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[2] Case 91-M-0509, *Proceeding on Motion of the Commission to Consider Financial and Regulatory Policies for New York State Utilities*, Recommended Decision, (issued July 19, 1994) ("Generic Finance RD"), at 2.

[3] *Id*.

1 continued to provide fair returns.[4] The Commission's inquiry considered the merits
2 of a generic process to reduce redundancy in litigating equity returns, and sought a
3 robust, but standardized approach to setting ROE such that allowed returns were
4 commensurate with the risk of the individual company and would not be skewed
5 by the shortcomings of a single methodology.

6 **Q. PLEASE DESCRIBE THE CONCLUSIONS OUTLINED IN THE RECOMMENDED**
7 **DECISION OF THE GFP.**

8 A. Ultimately, the Recommended Decision ("RD") concluded that the Commission
9 should implement a generic process for setting returns, based on proxy groups (not
10 company-specific data), and that reliance on the DCF method should be replaced
11 with a combination of the DCF and CAPM methodologies. The RD proposed to
12 use as a preferred convention a respective 2/3 – 1/3 weighting on the results of the
13 DCF and CAPM analyses. The RD recognized that the CAPM "should figure
14 prominently in the analysis" because this methodology provides fundamental
15 information on interest rates and the returns required by equity investors as a result
16 of changes in interest rates. At that time, the CAPM was not accorded the same
17 level of prominence as the DCF analysis, given that the former had previously only
18 been used as a check.[5] However, while the RD recognized that there was a benefit
19 to establishing an "operating norm" with respect to weighting the results of the DCF

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4 *Id* at 13-14.
5 *Id* at 27.

and CAPM in setting the ROE, it also recognized that there may be good reason to adjust either the weightings of the DCF and CAPM models or to rely on different ROE estimation models. Specifically, the RD provides the following guidance:

> In either an annual-proceeding to determine a rate of return or in individual proceedings, the 2/3 DCF and 1/3 CAPM convention should be the presumption, but as Multiple Intervenors suggest, parties would not be barred from introducing new methods or different weightings. Such parties, however, would have the burden of convincing other parties and the Commission of the relevance or superiority of their proposals. [6]

To establish the "operating norm," the RD recommended specific forms of the ROE estimation models – a two-stage DCF approach and a Traditional and Zero Beta CAPM. In the DCF model, the first-stage growth was determined by the implied growth rate in Value Line dividend forecasts for four- to six-years in the future. The second growth rate began with the end of the four- to six-year period of the first stage and extended infinitely. The second stage included what is termed an SV adjustment for external growth through additional equity issuances.[7] The CAPM result was proposed to be based on the average of the Traditional and Zero-Beta forms of the model.[8] Dividend yields in the DCF analysis and the risk-free bond yields in the CAPM analyses were based on six months of yield data.[9] Equity

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[6] *Id*.
[7] *Id* at 21.
[8] *Id* at 24.
[9] *Id* at 26.

1 ratios were capped at the upper end of the levels necessary to maintain an "A" bond
2 rating.[10] Although the GFP RD was never formally adopted by the Commission, it
3 has served as a touchstone for the Commission's ROE determinations for the past
4 20 years, as the Commission's ROE determinations have used the template
5 advocated in the RD.

6 **Q. DOES THE ANALYSIS PRESENTED IN THE REMAINDER OF YOUR DIRECT**
7 **TESTIMONY MEET THE INTENTIONS OF THE GFP RD?**

8 A. Yes, it does. As discussed in greater detail in Section VI, the methodologies that I
9 have applied to estimate the cost of equity for Distribution are consistent with
10 Commission precedent since the RD in the GFP. Moreover, the models used in my
11 analysis extend the principles advanced in the RD in the GFP to best practices in
12 financial analysis and current capital market conditions, as was contemplated in the
13 RD.

14 Specifically, I rely on the weighted results of DCF and CAPM analyses. In
15 developing these ROE estimation models, I rely on proxy groups of risk-
16 comparable companies as discussed in Section V. I have used both the DCF and
17 CAPM methodologies to estimate the return on equity. The multi-stage DCF model
18 that I relied on is consistent with the methodology the Commission has relied on in
19 that it allows growth rates to vary over time. Consistent with the fundamental

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[10] *Id* at 43.

principles upheld by the Commission, I have applied two versions of the CAPM: Traditional and Zero Beta. Finally, consistent with the principles of the GFP, to reduce the volatility associated with the reliance on any one model, I arrived at my ROE recommendation by weighting the results of the DCF and CAPM.

Q. DO THE PRINCIPLES AND INTENTIONS OF THE RD IN THE GFP REQUIRE ADHERENCE TO A STATIC FORMULA?

A. No. The GFP and RD did not require rote adherence to a static formula. The Commission's decision to open the GFP and the subsequent RD promoted the same principles and intentions as are in practice today. The Commission recognized that the ROE estimation models were not providing results that were reasonable and reflective of the risks of the individual companies involved in rate proceedings. Therefore, the Commission sought to reexamine the methodologies relied on and to restructure its process in order to achieve a more reasonable result.

The RD recognized the benefit of using multiple approaches for setting ROE and although it found benefits to a preferred convention for setting ROE, it did not bar parties from introducing new cost of capital estimation methods or weightings. The RD specifically recognized that there may be circumstances where departure from the weightings that were established at that time would be warranted. Capital market conditions vary widely over time, and each ROE methodology currently considered by the Commission (DCF and CAPM) may be affected differently by those conditions. The effect of these conditions on the cost of equity must be

assessed and interpreted by the practitioner to determine if their effects are directionally appropriate and are of a reasonable magnitude. Accordingly, it is incumbent on the practitioner to review the results of the analyses and exercise judgment as to how to weight those results in the overall ROE determination. The RD demonstrates that there was some uncertainty around the weighting of the DCF and CAPM methodologies, and therefore the RD indicates a willingness to revisit the proposed weightings in the future. It is particularly fitting that the Commission, which is seeking to update the traditional utility regulatory model with new, innovative approaches suitable to current industry circumstances in the New York Reforming the Energy Vision ("NY REV") efforts, Case 14-M-0101, consider the integrity of the intent and principles of the RD and demonstrate the flexibility to adapt the weightings of each methodology to the applicable capital market conditions.

Q. IS FLEXIBILITY OF APPROACH AND JUDGMENT IMPORTANT TO ROE DETERMINATION?

A. Yes, it is. When faced with the task of estimating the cost of equity, analysts benefit from gathering and evaluating as much relevant data (both quantitative and qualitative) as can be reasonably considered. Analysts and academics understand that ROE models are tools to be used in the ROE estimation process, and that strict adherence to any single approach, or the specific results of any single approach, can lead to flawed conclusions. No model can exactly pinpoint the correct return on

1 equity; rather, each model brings its own perspective and set of inputs that inform
2 the ROE estimate. That position is consistent with the *Hope* finding that "[u]nder
3 the statutory standard of 'just and reasonable,' it is the result reached, not the
4 method employed, which is controlling."[11]

5 Although each model brings a different perspective, each model also has its own
6 inherent weaknesses and should not be relied upon individually without
7 corroboration from other approaches. Changes to assumptions as a result of
8 changes in economic and capital market conditions could have widely varying
9 impacts on the results of the various analyses.

10 Regardless of which analyses are performed to estimate the investor's required
11 ROE, the analyst must apply judgment to assess the reasonableness of results and
12 to determine the best weighting to apply to results under prevailing capital market
13 conditions. No one model can reliably and consistently estimate the cost of capital
14 that meets the fairness standard of *Hope* and *Bluefield* in all market conditions.

IV. CAPITAL MARKET CONDITIONS

15 **Q. WHY IS IT IMPORTANT TO ANALYZE CAPITAL MARKET CONDITIONS?**

16 A. The ROE estimation models rely on market data that is either specific to the proxy
17 group, in the case of the DCF model, or the expectations of market risk, in the case
18 of the CAPM. The results of the ROE estimation models can be affected by market

[11] *Hope*, 320 U.S. at 602.

conditions that are present at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward looking, the practitioner uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates in the ROE estimation models to estimate the required return for the subject company. It is important to consider whether the assumptions relied on in the current market or the projected data relied upon are sustainable over the period that the recommended ROE would be in effect. If the conditions are not expected by investors to be sustained in the future, it is possible that the ROE estimation models will not provide an accurate estimate of investors' required return.

Q. WHAT FACTORS ARE AFFECTING THE COST OF EQUITY FOR REGULATED UTILITIES IN THE CURRENT AND PROJECTED CAPITAL MARKETS?

A. The cost of equity for regulated utility companies is being affected by several significant factors in the current and projected capital markets. These factors include: (1) the market's expectation for higher interest rates; (2) current low yields on utility stocks; (3) current high valuations on utility shares relative to historical levels; and (4) increasing credit spreads between yields on Treasury bonds and utility bonds. In this section of my Direct Testimony, I will discuss each of these factors and how it affects the Cost of Equity for regulated utilities.

1 **Q. WHAT EFFECT DO RISING INTEREST RATES HAVE ON THE COST OF EQUITY FOR**
2 **REGULATED UTILITIES?**
3 A. When interest rates are rising, especially after a prolonged period of low interest
4 rates, the calculated cost of equity for the proxy companies using current market
5 data is likely to understate investors' required return. Consequently, rising interest
6 rates support selection of a return toward the upper end of a reasonable range of
7 equity cost rate estimates that are based on current market data. As an alternative,
8 the analyses I present include estimated returns based on near-term projected
9 interest rates.
10 **Q. WHAT IS THE EXPECTED TIMING OF AN INCREASE IN SHORT-TERM INTEREST**
11 **RATES BY THE FEDERAL RESERVE?**
12 A. In mid-December 2015 the Federal Reserve announced the first increase in short-
13 term interest rates since the financial market collapse in 2008. In its accompanying
14 statement, the Federal Reserve indicated that further increases in short-term interest
15 rates would be gradual as the economy strengthens and inflation rises from
16 undesirably low levels. In March 2016, the Federal Reserve indicated that global
17 economic and financial market developments continued to pose risks and inflation
18 remained below the 2 percent target level. Therefore, the Federal Reserve did not
19 adjust short-term interest rates. Rather, the Federal Reserve indicated it expects
20 gradual increases in the federal funds rate. Since that time, Federal Reserve
21 officials have suggested that there could be a rate increase as early as the April or

June 2016 FOMC meetings.[12] Goldman Sachs has also suggested that the Federal Reserve will need to increase rates at its originally projected four times in 2016 due to an increase in core inflation.[13]

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF HIGHER INTEREST RATES FOR NATURAL GAS DISTRIBUTION COMPANIES SUCH AS THE COMPANY?

A. Many income-oriented investors hold utility stocks for their dividend yields. During periods in which interest rates are expected to increase, the dividend yields of utility stocks become less attractive for income-oriented investors relative to bond yields, placing pressure on utility share prices relative to the broader market. The potential for rising interest rates indicates that the calculated cost of equity for the proxy companies using any estimation technique that relies on discounted cash flows is likely to lag investors' required return during the period that Distribution's rates will be in effect. Consequently, a consensus expectation of rising interest rates supports selection of a return for Distribution at the higher end of the range of results for the DCF model.

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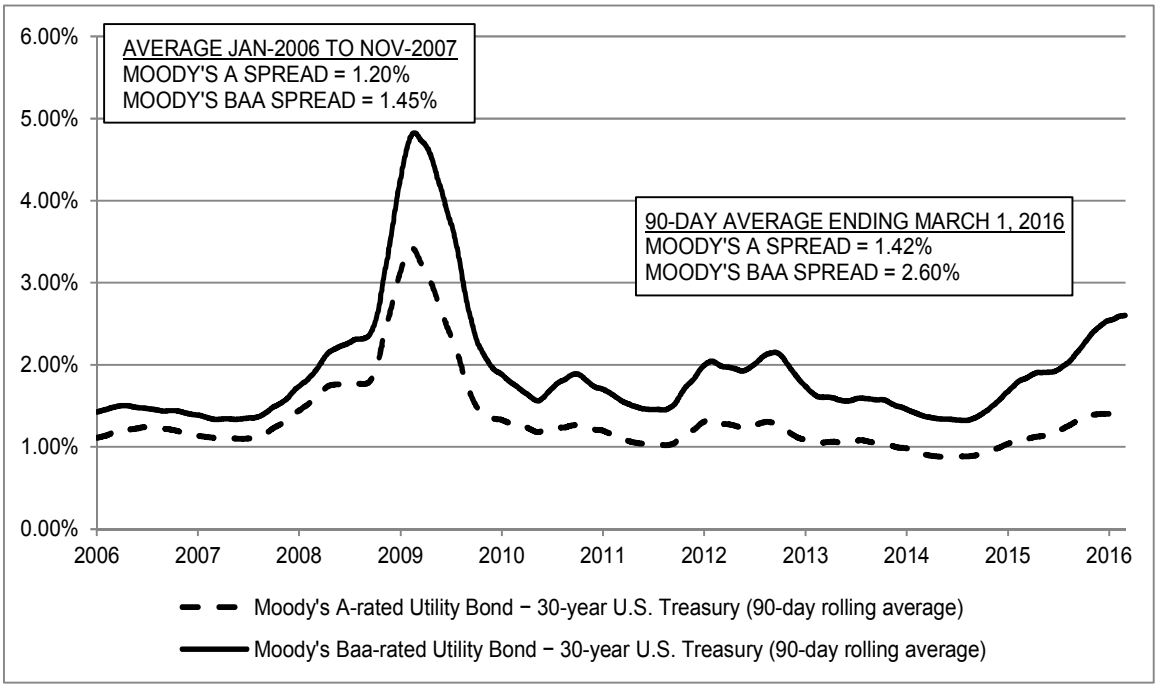
12 Two Fed Officials Point to Possibility of April Rate Hike, BloombergBusiness, March 21, 2016.

13 Goldman: Global Coordinated Easing Won't Last, and the Fed will need to Hike Rates Four Times in 2016, BloombergBusiness, March 21, 2016.

1 **Q. HOW HAS THE PERIOD OF ABNORMALLY LOW INTEREST RATES AFFECTED THE**
2 **VALUATION AND DIVIDEND YIELDS OF UTILITY SHARES?**
3 A. The ROE that is established in this proceeding is intended to reflect investors'
4 required return over the forward-looking period during which the established rates
5 will be in effect. The Federal Reserve's Quantitative Easing program resulted in
6 higher asset prices for many common stocks and lower interest rates on government
7 bonds. The shares prices of public utility companies experienced higher valuations
8 over the past several years, as investors sought higher returns and more attractive
9 yields than were being offered by Treasury bonds. Consequently, the current share
10 price of many utility stocks has increased to levels above Value Line's target price
11 for the 2018-2020 period, while the dividend yield of those same utility stocks has
12 declined to unusually low levels. While Federal market intervention reduced
13 interest rates on government bonds over the last several years, interest rates are
14 expected to rise over the period when the rates that are established for the Company
15 in this proceeding will be in effect. Therefore, it is not appropriate to base the
16 allowed ROE entirely on the historical level of interest rates.
17 **Q. ARE THERE INDICATIONS THAT INVESTOR RISK SENTIMENT IS INCREASING IN**
18 **FINANCIAL MARKETS?**
19 A. Yes. Even as Treasury bond yields have remained relatively low in 2015 and the
20 first quarter of 2016, yields on corporate and utility bonds have increased steadily.
21 Consequently, as shown on Chart 1, credit spreads between Treasury bonds and

utility bonds have increased to the highest level since the credit and financial crisis. In particular, the spread between Baa-rated utility debt and Treasury bonds is now 260 basis points. Incremental credit spreads are a widely-recognized measure of investor risk sentiment. Wider credit spreads indicate that investors are requiring a higher premium (*i.e.*, a higher interest rate) to compensate them for the higher risk associated with longer-term or lower-rated debt instruments.

Chart 1: Credit Spreads for Moody's A- and Baa-rated Utility Bonds



Q. HAVE YOU CONDUCTED ANY ANALYSIS OF INVESTOR RISK SENTIMENT AS COMPARED WITH THE MARKET CONDITIONS AT THE TIME OF DISTRIBUTION'S 2014 SETTLEMENT OF THE SHOW CAUSE CASE?

A. Yes. I compared the average credit spreads between various government and corporate bonds as of March 1, 2016 to the average spreads as of May 8, 2014, which is the time period of Distribution's most recent settlement of its show cause proceeding which involved an inquiry into its rates and earnings. As shown in Table 2, the average credit spreads as of March 1, 2016 were 54 to 126 basis points higher than in May 2014.

Table 2: Credit Spreads

Bond Yields	Current Credit Spreads 3/1/16	5/8/2014 Distribution 2014 Settlement	Great Recession 12/3/2007-6/30/2009
Moody's Baa-rated - Moody's A-rated Utility Bond	1.19%	0.46%	0.91%
Moody's Baa-rated Utility Bond – 30-year U.S. Treasury	2.60%	1.34%	3.23%
Moody's A-rated Utility Bond – 30-year U.S. Treasury	1.42%	0.88%	2.32%

In particular, the spread between the Moody's Baa-rated utility bond index and the Moody's A-rated utility bond index has increased from 46 basis points at the time the Commission last examined Distribution's rates to 119 basis points as of March

1, 2016, which is much greater than the 91 basis point spread that prevailed during the "Great Recession" of 2007-2009. Similarly, the spread between the Moody's Baa-rated utility bond index and the 30-year Treasury yield has increased from 134 basis points to 260 basis points, and the spread between the Moody's A-rated utility bond index and the 30-year Treasury yield has increased from 88 basis points to 142 basis points. These wider credit spreads are an indication of higher risk sentiment among utility bond investors, despite lower yields on U.S. Treasury bonds. It is reasonable to reflect higher investor risk sentiment through a higher cost of equity.

Q. WHAT DO CREDIT SPREADS INDICATE ABOUT THE MARKET?

A. Higher credit spreads are an indication that bond investors are becoming more concerned about future economic conditions and the ability of corporations to withstand any downturn that may occur in the economy. The Wall Street Journal reported on the trend toward higher credit spreads as follows:

> The U.S. corporate bond market is starting to flash caution signals about the broader economy. The difference in yield, called the "spread," between bonds from America's strongest companies and ultrasafe U.S. Treasury securities has been steadily increasing, a trend that in the past has foreshadowed economic problems. Wider spreads mean that investors want more yield relative to Treasurys to own bonds from U.S. companies. It can signal that investors are less confident about companies' business prospects and financial health, though other factors likely also are at play. Spreads in investment-grade corporate bonds – debt from companies rated triple-B minus or higher – are on track to increase for the second year in a row, according to Barclays data. That would be the first time since

> the financial crisis in 2007 and 2008 that spreads widened in two consecutive years.
>
> ***
>
> Investors and analysts say they are closely watching the action to determine whether trouble is brewing once again. Concerns are growing about companies' ability to pay back the massive debt load taken on in recent years, as ultralow interest rates spurred corporate finance chiefs to sell record amounts of debt.[14]

Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE EFFECT OF CAPITAL MARKET CONDITIONS ON THE COST OF EQUITY?

A. Against this backdrop of rising interest rates, widening credit spreads, and higher investor risk sentiment, the cost of capital for all companies, including regulated utilities, has increased. As such, the ROE for Distribution should be based on market conditions that are expected during the period that the rates set in this proceeding will be in effect, not based on the low interest rate environment of the past few years.

Q. WHAT OVERALL CONCLUSIONS DO YOU DRAW FROM YOUR ANALYSIS OF CAPITAL MARKET CONDITIONS?

A. Because the utility sector has been trading at higher price multiples than the historical range, it is important to consider whether or not those multiples and relationships will remain constant over time, as is assumed in the DCF model. Furthermore, since interest rates are projected to increase substantially, it is

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[14] "U.S. Bonds Flash a Warning Sign," The Wall Street Journal, September 28, 2015, at C1.

1 important to reflect that expectation in the specification of the CAPM and other risk
2 premium models.

V. PROXY GROUP SELECTION

3 **Q. WHY YOU HAVE USED A GROUP OF PROXY COMPANIES TO ESTIMATE THE COST OF**
4 **EQUITY FOR THE COMPANY?**

5 A. In this proceeding, we are focused on estimating the cost of equity for the
6 Company's rate-regulated, natural gas distribution utility operations in New York.
7 Because ROE is a market-based concept and the Company is not publicly traded, it
8 is necessary to establish a group of companies that is both publicly traded and
9 comparable to Distribution in certain fundamental business and financial respects
10 to serve as proxies in the ROE estimation process. The proxy companies used in
11 my analyses all possess a set of operating and risk characteristics that are
12 substantially comparable to the Company and thus provide a reasonable basis for
13 the derivation and assessment of the Company's ROE.

14 In utility rate proceedings before the Commission over the past 20 years (since the
15 RD in the GFP),[15] the Commission has endorsed the use of proxy groups for the
16 purpose of determining utility ROEs. Because proxy companies are now
17 commonly used as the basis for estimating the utility cost of equity, the primary
18 objective of the screening process is to establish a group of companies that is as

[15] Generic Finance RD at 133-134.

comparable as possible to the subject company with respect to fundamental financial and business risks. While the determination of an appropriate ROE necessarily requires a degree of informed judgment, the careful selection of a risk-comparable proxy group serves to mitigate the extent to which subjective assessments must be applied.

Q. PLEASE PROVIDE A SUMMARY PROFILE OF THE COMPANY.

A. The Company distributes natural gas or provides natural gas transportation services to approximately 526,000 customers in western New York and 214,000 customers in northwestern Pennsylvania.[16] Distribution's parent, National Fuel Gas Company, long-term issuer ratings are Baa3 (Moody's), BBB (Standard and Poor's or "S&P") and BBB (Fitch Ratings, or "Fitch").[17]

Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUPS?

A. Because Distribution is a natural gas distribution company, it is appropriate to establish a proxy group that recognizes the risks of natural gas distribution operations. Therefore, the initial proxy group selected is from the universe of companies that Value Line classifies as "Natural Gas Distribution Companies", which is currently composed of 12 companies. In order to establish a risk-comparable proxy group, I applied similar criteria to those relied on by the Commission in prior cases:

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[16] National Fuel Gas Company Investor Presentation, February 2016, at 28.
[17] Source: SNL Financial, accessed April 4, 2016.

- I eliminated companies that are not covered by at least two utility industry equity analysts;
- I eliminated companies that do not have investment grade corporate credit ratings and/or senior unsecured bond ratings from S&P and Moody's because such companies do not have a similar investment risk profile to that of the Company;
- I eliminated companies that have not paid regular dividends or do not have positive earnings growth projections from at least one source because such characteristics are incompatible with the DCF model;
- To ensure that the proxy group consists of companies that are primarily regulated utilities, I eliminated companies with less than 70 percent of total operating income derived from regulated utility operations;
- To ensure that the proxy group consists of entities that are primarily natural gas distribution utilities, I eliminated companies that derive less than 50 percent of total regulated operating income from regulated natural gas distribution operations; and
- I eliminated companies known to be party to a merger, acquisition, or other transformational transaction.

Q. WHAT IS THE COMPOSITION OF YOUR NATURAL GAS PROXY GROUP?

A. My Natural Gas Proxy Group consists of the seven companies in Table 3.

Table 3: Natural Gas Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
Laclede Group	LG
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
WGL Holdings, Inc.	WGL

Q. IS A PROXY GROUP OF SEVEN COMPANIES A REASONABLE SIZE TO ESTIMATE THE COST OF EQUITY?

A. While I recognize that the Natural Gas Proxy Group is somewhat limited in size, because the Company is a natural gas distribution utility, the Natural Gas Proxy Group may be more risk comparable to the Company than a proxy group that includes other regulated entities. However, I am aware that the Commission has historically relied on proxy groups generally composed of electric utilities even for the purposes of establishing the ROE for a natural gas distribution utility. In recognition of that practice, I also considered a proxy group composed of companies that Value Line classifies as "Electric Utilities" and "Natural Gas Distribution Companies." That combined group includes 56 domestic U.S. utilities. I simultaneously applied the following screening criteria to establish a risk-comparable Combined Utility Proxy Group that includes electric utility companies with natural gas operations and natural gas distribution companies:

- I eliminated companies that are not covered by at least two utility industry equity analysts;
- I eliminated companies that do not have investment grade corporate credit ratings and/or senior unsecured bond ratings from S&P and Moody's;
- I eliminated companies that have not paid regular dividends or do not have positive earnings growth projections from at least one source;
- To ensure that the proxy group consists of companies that are primarily regulated utilities, I eliminated companies with less than 70 percent of total operating income derived from regulated utility operations;
- To ensure that the proxy group consists of entities with gas utility operations, I eliminated companies that derive less than 10 percent of total regulated operating income from regulated natural gas distribution operations; and
- I eliminated companies known to be party to a merger, acquisition, or other transformational transaction.

Q. WHAT IS THE COMPOSITION OF YOUR COMBINED UTILITY PROXY GROUP?

A. My Combined Utility Proxy Group consists of the 19 companies in Table 4.

Table 4: Combined Utility Proxy Group

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
Atmos Energy Corporation	ATO
Avista Corporation	AVA
CenterPoint Energy, Inc.	CNP
CMS Energy Corporation	CMS
Consolidated Edison, Inc.	ED
DTE Energy Company	DTE
Laclede Group, Inc. (The)	LG
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
NorthWestern Corporation	NWE
SCANA Corporation	SCG
Sempra Energy	SRE
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
Vectren Corporation	VVC
WGL Holdings, Inc.	WGL
Xcel Energy Inc.	XEL

Q. WHY DO YOU BELIEVE THAT NET OPERATING INCOME IS AN APPROPRIATE SCREENING CRITERION?

A. In establishing my proxy group, I relied on the percentage of net operating income derived from regulated operations instead of the percentage of total revenue derived from regulated operations because net operating income is more representative of the contribution of that business segment to earnings and the corporation's overall

1 financial position. Specifically, a significant portion of gas and electric utility
2 company revenue is derived from the costs of purchased gas, purchased fuel, and
3 purchased power, which, in most cases, are recoverable through tracking
4 mechanisms and do not, therefore, contribute to earnings. Furthermore, this portion
5 of total revenue can fluctuate considerably based on the cost of gas and other inputs.
6 Therefore, relying on a revenue screen does not provide a clear or necessarily
7 consistent indicator of the contribution of the regulated utility operations to a
8 company's earnings, which are most the important consideration for equity
9 investors. Net operating income excludes the cost of purchased commodity, and
10 therefore more closely represents the contribution of the business segment to
11 earnings.

12 **Q. PLEASE PROVIDE AN EXAMPLE OF A COMPANY THAT HAS BEEN INCLUDED IN THE**
13 **PROXY GROUP BECAUSE NET OPERATING INCOME WAS USED INSTEAD OF TOTAL**
14 **REVENUE AS A SCREENING CRITERION.**

15 A. New Jersey Resources ("NJR") would have been excluded from the Combined
16 Utilities Proxy Group and the Natural Gas Proxy Group if the percentage of total
17 revenue from regulated operations were used as a screening criterion instead of the
18 percentage of net operating income from regulated operations. NJR has an Energy
19 Service segment that provides unregulated, wholesale natural gas to customers
20 including natural gas distribution companies, industrial companies and electric

generators in the U.S. and Canada.[18] In 2015, the Energy Service segment had operating revenues of approximately $1.9 billion.[19] When compared to NJR's total operating revenue of approximately $2.7 billion, it is clear that NJR's percentage of revenue derived from regulated operations would not meet the revenue screening criterion.[20] However, Energy Service's 2015 operating revenue consisted of $1.8 billion in natural gas purchases.[21] Therefore, the Energy Service segment does not represent a large percentage of NJR's net operating income. As discussed above, net operating income is the more appropriate screening criterion because it better approximates a business segment's contribution to earnings and the corporation's overall financial position. NJR operates a large natural gas distribution system in New Jersey and is generally regarded as a gas distribution company. The Energy Services segment of NJR accounts for a large percentage of the company's operating revenue, but a small percentage of net operating income. NJR's regulated operations contribute a larger portion to the company's earnings, and therefore NJR should be included in the Combined Utility Proxy Group and the Natural Gas Proxy Group.

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18 New Jersey Resource Corporation 2015 Form 10-K, page 10.
19 Ibid, page 45.
20 Ibid, page 68.
21 Ibid, page 46.

1 **Q. DO YOU BELIEVE THAT THE 19 COMPANIES IN YOUR COMBINED UTILITY PROXY**
2 **GROUP CONSTITUTES A SUFFICIENTLY LARGE PROXY GROUP?**
3 A. Yes, I do. The analyses performed in estimating the ROE are more likely to be
4 representative of the subject utility's cost of equity to the extent that the chosen
5 proxy companies are fundamentally risk comparable to the subject utility. Because
6 all analysts use some form of screening process to arrive at a proxy group, the
7 group, by definition, is not randomly drawn from a larger population.
8 Consequently, there is no reason to place more reliance on the quantitative results
9 of a larger and more dissimilar proxy group simply by virtue of the resulting larger
10 number of observations.
11 **Q. HAS THE COMMISSION TYPICALLY RELIED ON SIMILAR SCREENING CRITERIA**
12 **WHEN ESTIMATING THE ROE?**
13 A. Yes. The Commission has typically relied on screening criteria that are similar to
14 those that I have used to develop my proxy groups. The proxy group that is
15 typically relied on by the Commission is composed of a large group of dividend-
16 paying companies with investment grade bond ratings and regulated revenues of at
17 least 70 percent that are not party to merger-related or corporate restructuring
18 activities.[22] For the reasons noted above, a proxy group developed based on these
19 somewhat less selective criteria may be less comparable to the Company than the

[22] *See, e.g.,* Case 13-E-0030, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Testimony of Craig E. Henry, at 14-16.

two proxy groups I have relied on and therefore may not produce appropriate estimates of the investors' required ROE for the Company.

VI. COST OF EQUITY ESTIMATION

Q. PLEASE BRIEFLY DISCUSS THE ROE IN THE CONTEXT OF THE REGULATED RATE OF RETURN.

A. The rate of return ("ROR") for a regulated utility is based on its weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective percentages of total capitalization of the utility. The ROE included in the ROR is weighted by the percentage of common equity in the regulated utility's capital structure.

Q. HOW IS THE REQUIRED ROE DETERMINED?

A. While the cost of debt can be directly observed, the cost of equity and the required ROE are market-based and, therefore, must be estimated based on observable market data. The required ROE is determined by using one or more analytical techniques that rely on market data to quantify investor expectations regarding the range of required equity returns. Informed judgment is applied, based on the results of those analyses, to determine where within the range of results the cost of equity for a company falls. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the

1 financial markets, the proxy group companies, and the subject company's risk
2 profile.

3 **Q. WHAT METHODS DID YOU USE TO ESTIMATE THE COMPANY'S COST OF EQUITY?**

4 A. Consistent with Commission precedent, I used the DCF model and CAPM as my
5 primary approaches. In establishing my recommended ROE, I relied on a multi-
6 stage form of the DCF model, and, consistent with the Commission's stated
7 preference, I used both the traditional form of the CAPM, as well as the Zero-Beta
8 form of that model. In both forms of the CAPM, I incorporated a forward-looking
9 measure of the Market Risk Premium.

10 **Q. WHY IS IT IMPORTANT TO USE MORE THAN ONE ANALYTICAL APPROACH?**

11 A. Because the cost of equity is not directly observable, it must be estimated based on
12 both quantitative and qualitative information. When faced with the task of
13 estimating the cost of equity, analysts and investors are inclined to gather and
14 evaluate as much relevant data as reasonably can be analyzed. A number of models
15 have been developed to estimate the cost of equity, and I use multiple approaches
16 to estimate the cost of equity. As a practical matter, however, all of the models
17 available for estimating the cost of equity are subject to limiting assumptions or
18 other methodological constraints. Consequently, many well-regarded finance texts
19 recommend using multiple approaches when estimating the cost of equity. For

1 example, Copeland, Koller, and Murrin[23] suggest using the CAPM and Arbitrage
2 Pricing Theory model, while Brigham and Gapenski[24] recommend the CAPM,
3 DCF, and "bond yield plus risk premium" approaches.[25]

4 **Q. HOW ARE CURRENT MARKET CONDITIONS AFFECTING THE RESULTS OF THE DCF**
5 **AND CAPM MODELS?**

6 A. The U.S. economy is experiencing an unprecedented period of low interest rates.
7 Low interest rates, and the effects of the investor "flight to quality" can be seen in
8 high utility share valuations relative to historical levels and relative to the broader
9 market, and in widening credit spreads. Higher utility stock valuations produce
10 lower dividend yields and result in lower cost of equity estimates from a DCF
11 analysis. Low interest rates also impact the CAPM in two ways: (1) the risk free
12 rate is lower, and (2) because the market risk premium is a function of interest rates,
13 (*i.e.,* it is the return on the broad stock market less the risk free interest rate), the
14 risk premium should move higher when interest rates are lower. Often, however,
15 the estimate of the market risk premium may not fully capture changes in interest
16 rates. It is important in periods of abnormally low interest rates to rely on a market

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23 Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

24 Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

25 While it has historically been my practice to present the results of a bond yield plus risk premium approach in the context of estimating a reasonable ROE, I have not done so in this case to limit the number of contested issues. The result of such an analysis, however, would support my CAPM ROE determinations.

risk premium that is responsive to changes in the level of interest rates such as a forward-looking market risk premium. Market risk premiums based on long-term historical averages are unresponsive to movements in interest rates and would likely understate the market risk premium and, accordingly, the cost of equity.

Q. ARE CURRENT MARKET CONDITIONS EXPECTED TO BE SUSTAINED FOR THE LONG TERM?

A. As discussed in Section IV of my testimony, interest rates are at or near the very lowest levels in decades and are expected to increase during the period when the rates that are authorized in this case will be in effect. The long-term historical relationship between interest rates on Treasury bonds and utility returns has been positive, suggesting that the expectation of rising interest rates would also result in an increase in the expected utility equity costs. Consequently, I have accounted for the likelihood of interest rates rising during the period when rates will be in effect in my CAPM analyses by calculating estimated returns based on near-term projected interest rates.

Q. HOW HAVE RECENT MARKET CONDITIONS AFFECTED THE ASSUMPTIONS USED IN THE DCF MODEL?

A. The currently high price-to-earnings ("P/E") ratios for utility stocks have the effect of depressing the expected return in the DCF model. Because the multi-stage DCF model solves for the return required on the projected earnings stream at the current stock price, if market participants believe that stock prices are not sustainable, as is

the case in the current market, the DCF model will tend to underestimate the cost of equity.

In its commentary on the electric utility industry, Value Line reported that many companies are currently trading at share prices near or exceeding their four- to six-year price targets. Furthermore, Value Line recently cautioned investors about electric utility stock prices:

> Most utilities are trading within their 2019-2021 Target Price Range, and some are trading near the upper end of this range. This indicates that these stocks are expensively priced. The average dividend yield of electric utility stocks is now 3.6%, which is low by historical standards.[26]

Chart 2 summarizes the average historical and projected P/E ratios for the proxy companies calculated using data from Bloomberg Professional and Value Line. As shown in Chart 2, the average P/E ratio for the proxy companies was higher at the end of 2015 than the average projected P/E ratio for the group for the period from 2018-2020. This is important because the multi-stage DCF model is calculating the return on equity based on a potentially unsustainably high P/E ratio. All else equal, if P/E ratios for utilities decline, similar to Value Line's projections, the ROE results from the DCF model would be higher.

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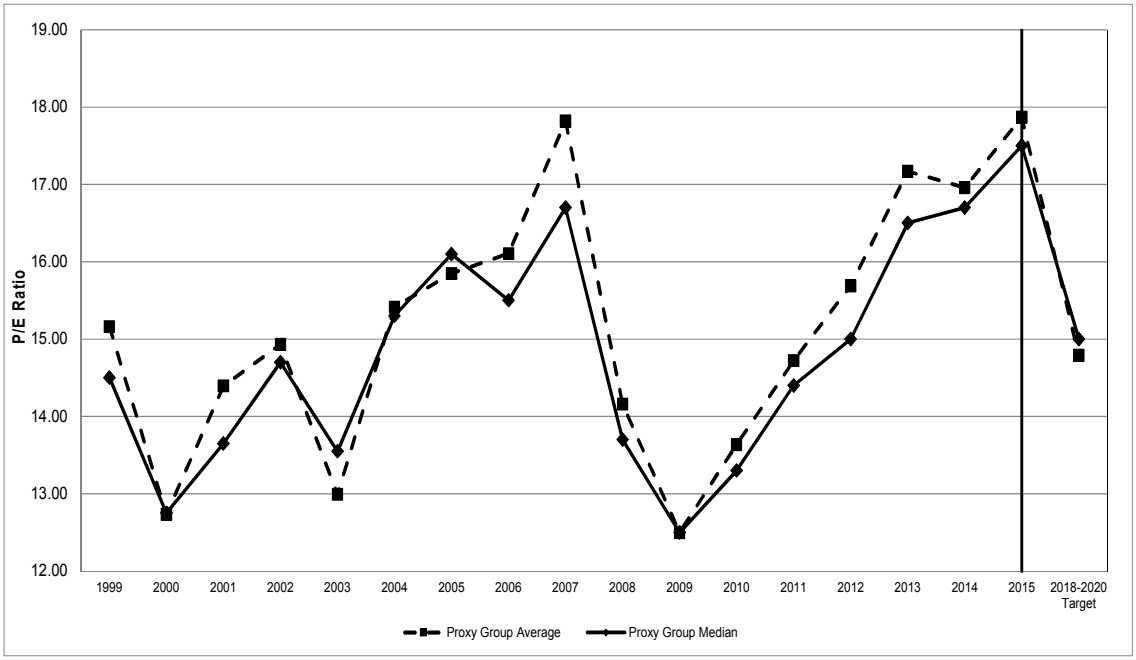
[26] Value Line Electric Utility (Central) Industry, March 18, 2016, at 901.

Chart 2: Average Historical P/E Ratios for Combined Proxy Group



Q. VALUE LINE HAS OBSERVED THAT DIVIDEND YIELDS ARE LOW RELATIVE TO HISTORICAL STANDARDS. WHY IS THIS RELEVANT IN ESTIMATING THE ROE IN THIS CASE?

A. The ROE that is established in this case is intended to be a forward-looking ROE that Distribution will be authorized to earn over some future rate period. The analysis that is used to set that return is based on current data for the proxy companies. It is important to understand how market conditions affect the assumptions used in the DCF and CAPM and ultimately the results of those models. As noted by Value line, electric utility stock prices are high, making the dividend yields low on a historical basis. Relying on lower dividend yields in the DCF model will result in a lower estimated ROE from that model, holding all other assumptions

constant. To the extent that low dividend yields are not expected to be representative of market conditions over the period that this ROE will be in effect, then the DCF model may be understating the market required ROE.

Q. ARE YOU AWARE OF ANY OTHER REGULATORS THAT CONSIDERED THE EFFECTIVENESS OF THE TRADITIONAL ROE ESTIMATION MODELS BASED ON CHANGING MARKET CONDITIONS?

A. Yes, I am. The Surface Transportation Board ("STB"), which regulates the U.S. railroad industry, began evaluating the effectiveness of the constant growth DCF model in September 2006. The STB instituted a broad rulemaking to obtain public comment on the most appropriate methodology to use for estimating the ROE for railroads. In January 2008, the STB replaced the constant growth DCF model with the CAPM, with the expectation that the CAPM would produce more accurate estimates of the industry's cost of capital. In January 2009, as a result of its exploration of the various forms of ROE estimation models and the review of public comments on the merits and shortcomings of each of the models, the STB issued a decision modifying its sole reliance on the CAPM to include an equal weighting of the CAPM and the multi-stage DCF results. In reaching this decision, the STB concluded that:

> Indeed, if our exploration of this issue has revealed nothing else, it has shown that there is no single simple or correct way to estimate the cost of equity for the railroad industry, and countless reasonable options are available. Both the CAPM and the multi-stage DCF models we propose to use have strengths

> and weaknesses, and both take different paths to estimate the same illusory figure. By using an average of the results produced by both models, we harness the strengths of both models while minimizing their respective weaknesses.[27]

This decision supports that it is appropriate to consider the results of various financial models to estimate the cost of equity within the context of capital market conditions, and that the appropriate method(s) can evolve over time as market conditions change. As discussed earlier in my Direct Testimony, the Commission came to a similar conclusion when it opened the GFP to assess whether the results of the DCF model were being distorted by low interest rate.

Q. IS IT RELEVANT THAT THE STB DOES NOT REGULATE THE ENERGY INDUSTRY?

A. No. The STB decision is an opinion on the appropriate methodologies to consider in estimating the ROE, and therefore it is relevant regardless of the industry. The STB decision describes the rigorous analysis and the methodologies that a regulatory body used to review financial models and to select the most appropriate models in the context of capital market conditions in order to estimate the cost of equity. In summary, as the STB decision points out, the models used to estimate the ROE are used by the investment community for all types of investments, and therefore it is not important that the STB does not regulate energy companies.

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[27] Surface Transportation Board, Use of a multi-stage Discounted Cash Flow Model in Determining the Railroad Industry's Cost of Capital, Decision STB Ex Parte No. 664 (Sub-No. 1), released January 28, 2009, at 15.

Rather, what is important is that the methodologies used reflect what investors consider in establishing their return requirements.

Q. ARE THERE OTHER REGULATORY AGENCIES THAT HAVE RECOGNIZED THAT THE DCF MODELS ARE CURRENTLY UNDERSTATING THE COST OF EQUITY?

A. Yes. Recently, in Opinion No. 531, the Federal Energy Regulatory Commission ("FERC") recognized that the inputs to the DCF model have been affected by anomalous market conditions and therefore, for the first time, is considering the use of other ROE estimation models.

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns established by the two-step constant growth DCF methodology.[28]

Q. HAS FERC PROVIDED ANY GUIDANCE ON HOW IT WILL ADDRESS THE ANOMALOUS CONDITIONS IN THE MARKET THAT AFFECT THE ASSUMPTIONS USED IN THE DCF MODEL?

A. Yes, FERC has traditionally relied on the midpoint or median of the range of results from the DCF model, which it refers to as the "zone of reasonableness" (defined by the low and high estimates making up the range). In Opinion No. 531, FERC

[28] 147 FERC ¶ 61,234, para. 41.

indicated that it will look at other ROE estimation methodologies to inform its judgment as to where, within the zone of reasonableness, the ROE should be set. In particular, FERC found risk premium-based approaches informative, including the CAPM.

> We are concerned that market conditions in the record are anomalous, thereby making it more difficult to determine the return necessary for public utilities to attract capital. In these circumstances, we have less confidence that the midpoint of the zone of reasonableness established in this proceeding accurately reflects the equity returns necessary to meet the *Hope* and *Bluefield* capital attraction standards. We find it is necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the resulting midpoint.[29]

> The NETOs [New England Transmission Owners] presented five alternative benchmark methodologies in this proceeding: risk premium analysis, the CAPM, comparison of electric ROEs with natural gas pipeline ROEs, comparison of electric utility DCF results with non-utility DCF results, and expected earnings analysis. Of those five, we find the risk premium analysis, the CAPM, and expected earnings analyses informative, and each produces a midpoint (or median) ROE higher than the midpoint of our DCF analysis here. In considering these other methodologies, we do not depart from our use of the DCF methodology; rather, we use the record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness established in the record by the DCF methodology.[30]

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[29] 147 FERC ¶ 61,234, para. 145.
[30] 147 FERC ¶ 61,234, para. 146.

> [W]e conclude that a mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of *Hope* and *Bluefield*.[31]

The FERC's decision supports my conclusion that because the results of the DCF model have been affected by anomalous market conditions, in setting the appropriate ROE, it is important to more heavily weight the results of other ROE estimation models, particularly the CAPM.

Q. WHAT ASSUMPTIONS USED IN THE CAPM HAVE BEEN AFFECTED BY CURRENT MARKET CONDITIONS?

A. The CAPM relies on the risk-free rate, the market risk premium and a measure of the relative risk of the proxy group to the market (Beta) to estimate the cost of equity for the proxy group. As discussed previously, the risk-free rate has been low by historical standards as a result of recent federal monetary policy and overall market volatility. As discussed in Section IV, government bond yields are expected to increase in the short term; it is therefore reasonable to rely on the projected yields on Treasury bonds in the CAPM analysis to more appropriately reflect the return on equity during the rate period.

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[31] 147 FERC ¶ 61,234, para. 142.

Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE RESULTS OF THE DCF AND CAPM MODELS?

A. The results of both models have been affected by market conditions and, with traditional data inputs, have a tendency to underestimate the cost of equity that investors would require over the period that the rates in this case are to be in effect. The DCF model results are currently understated because P/E ratios are high, and are not expected to remain at current levels. When prices are high, the dividend yields in the DCF model are low. If prices are not expected to remain at the currently high levels then the results of the DCF model using higher than expected prices will tend to understate the required return of equity.

The CAPM is affected by the current artificially low yields on Treasury bonds. The expectation that bond yields will not remain at currently low levels means that the expected cost of equity would be higher than is suggested by the CAPM using current yields. The use of projected yields on Treasury bonds results in CAPM estimates that are more reflective of the market conditions that investors expect during the period that the Company's rates will be in effect. Therefore, properly specified, the CAPM is a more reliable model in current market conditions than the DCF. Given the sensitivity of each of these models to market conditions, it is appropriate to provide equal weight to the results of the DCF and CAPM models at this time.

1 **Q. PLEASE COMPARE THE METHODOLOGIES THAT YOU RELY ON WITH THE**
2 **METHODOLOGIES THAT THE COMMISSION HAS TYPICALLY RELIED ON IN PRIOR**
3 **CASES.**
4 A. Prior to the GFP, the Commission relied on company-specific return calculations
5 using only the DCF methodology. The RD of the GFP acknowledged that the
6 previously relied on DCF methodology had been volatile and was very sensitive to
7 fluctuations in interest rates.[32] As a result, the RD suggested that the Commission
8 move to a generic process for estimating the rate of return using a proxy group-
9 based analysis, instead of a company-specific computation, relying on both the
10 DCF and CAPM methodologies.[33]
11 The methodologies that I have applied to estimate the cost of equity are consistent
12 with Commission precedent since the RD in the GFP. I rely on a proxy group of
13 risk-comparable companies. I have used both the DCF and CAPM methodologies
14 to estimate the cost of equity. The specific form of the DCF model that I relied on
15 meets all objectives of the Commission in that it is a multi-stage form of the DCF
16 that allows growth rates to vary over time.
17 The CAPM analyses I rely on are also consistent with the fundamental principles
18 upheld by the Commission. I have applied two versions of the CAPM: Traditional

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[32] Case 91-M-0509, *Proceeding on Motion of the Commission to Consider Financial and Regulatory Policies for New York State Utilities*, Recommended Decision, (issued July 19, 1994) ("Generic Finance RD"), at 13-14.

[33] *Id* at 27.

and Zero Beta. The Traditional CAPM determines the cost of equity by adding the risk-free rate to the proxy group beta times the market risk premium. The specific assumptions used in my CAPM are forward-looking, relying on a projected market risk premium and forward-looking interest rates. The Zero Beta CAPM is used as an alternative that accounts for the fact that the CAPM tends to underestimate the ROE for companies with a Beta less than 1.0 while overstating the ROE for companies with a Beta greater than 1.0. Both of these CAPM variants have been relied on by the Commission in past rate proceedings.

Finally, consistent with the principles of the GFP, to avoid over-reliance on any one model, I arrived at my ROE recommendation by equally weighting the results of the DCF and CAPM. In summary, the models used in my analysis are fundamentally consistent with the principles that the Commission has relied on in prior rate cases and the RD in the GFP. Moreover, the models used in my analysis are robust and extend the principles advanced in the RD in the GFP to best practices in financial analysis and current capital market conditions.

A. DISCOUNTED CASH FLOW MODEL

Q. ARE DCF MODELS WIDELY USED TO ESTIMATE THE ROE FOR REGULATED UTILITIES?

A. Yes. DCF models are widely used in regulatory proceedings and have sound theoretical bases, although neither the DCF model nor any other model can be applied without considerable judgment in the selection of data and the interpretation

of results. The Commission has used the results of the DCF model as one of the measures of the cost of equity in prior cases.

Q. PLEASE DESCRIBE THE DCF APPROACH.

A. The DCF approach is based on the theory that a stock's current market price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+r)^1} + \frac{D_2}{(1+r)^2} + \cdots + \frac{D_n}{(1+r)^n} \qquad [1]$$

Where P_0 represents the current market stock price, $D_1 \ldots D_n$ are all expected future dividends, and r is the discount rate, or required ROE. As discussed in more detail below, I have not included the constant growth form of the DCF model, but instead have focused on a multi-stage form of the DCF model.

1) Stock Prices used in the DCF Model

Q. WHAT MARKET DATA DID YOU USE TO CALCULATE THE CURRENT STOCK PRICE IN YOUR DCF MODEL?

A. The stock prices that I relied on in my DCF model are based on the average market closing prices for the proxy companies' shares over the three months ended March 1, 2016.

2) Multi-Stage DCF Model

Q. PLEASE GENERALLY DESCRIBE THE DCF MODEL YOU RELIED ON.

A. The multi-stage DCF model is an extension of the constant growth form that enables the analyst to specify growth rates over multiple stages. As with the

1 constant growth form of the DCF model, the multi-stage form defines the cost of
2 equity as the discount rate that sets the current price equal to the discounted value
3 of future cash flows. A multi-stage DCF model addresses the possibility that mean
4 five-year growth rates may not be reasonable in perpetuity.

5 **Q. PLEASE DESCRIBE THE STRUCTURE OF YOUR MULTI-STAGE DCF MODEL.**

6 A. My multi-stage DCF model sets the subject company's current stock price equal to
7 the present value of future cash flows received over three time periods. In all three
8 periods, cash flows are equal to the annual dividend payments that stockholders
9 receive. The first period is a short-term growth period that consists of the first five
10 years; the second period is a transition period from the short-term growth rate to
11 the long-term growth rate that occurs over five years (*i.e.*, years six through 10);
12 and the third period is a long-term growth period that begins in year 11 and
13 continues in perpetuity. The ROE is then calculated as the rate of return that results
14 from the initial stock investment and the dividend payments over the analytical
15 period.

16 **Q. HAS THE COMMISSION RELIED ON A MULTI-STAGE DCF MODEL IN PRIOR CASES?**

17 A. Yes, the Commission has relied on a two-stage form of the DCF model in prior
18 cases.[34] The two-stage model that the Commission has relied on and the multi-stage

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[34] *See* Case 10-E-0362, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service,* Order Establishing Rates for Electric Service, (issued June 17, 2011) ("2011 O&R Rate Order"), at 68-69.

model that I rely on both define the cost of equity as the discount rate that sets the current stock price equal to the discounted value of future cash flows, expressed as projected dividends. Both models project dividends using growth rates over multiple periods.

Q. IS THE MULTI-STAGE FORM OF THE DCF MODEL CONSISTENT WITH THE INTENT OF THE TWO-STAGE MODEL RELIED UPON BY THE COMMISSION?

A. Yes. Both the construction of the multi-stage model and the underlying assumptions are consistent with the two-stage model relied upon by the Commission. The constant growth DCF model assumes the expected growth rate will remain constant in perpetuity. The multi-stage forms of the DCF model, including both the two-stage model that the Commission has relied upon and the multi-stage form of the model that is relied on in my analysis, recognize short and long-term growth prospects.

Q. DOES THE MULTI-STAGE FORM OF THE DCF MODEL OFFER IMPROVEMENTS OVER THE TWO-STAGE MODEL TRADITIONALLY RELIED UPON BY THE COMMISSION?

A. Yes. The general form of the two-stage model relied upon by the Commission involves a near-term growth stage based on projected dividends and a long-term

growth stage employing an estimated long-term growth rate in dividends.[35] The Commission's application of a two-stage DCF model assumes that a company's growth abruptly shifts to a long-run growth rate after the initial five-year period. In contrast, the multi-stage model relies on growth rates over three periods. In Stage I (years one through five) dividends are increased based on analysts' estimates of earnings growth rates. Stage II is a transitional stage where the earnings growth rates are gradually transitioned over a five-year period (years six through ten) to the long-run sustainable growth rate that is used in the third stage. Stage III relies on a long-term GDP growth rate beginning in year 11 through year 200. The multi-stage form of the DCF model provides for a transition to a company's expected long-term growth, whereas the two-stage DCF model assumes the transition from short to long-term growth occurs in one-year.

Q. PLEASE SUMMARIZE THE GROWTH RATES THAT YOU RELIED ON IN THE MULTI-STAGE DCF MODEL.

A. As shown in Exhibits __ (AEB-1) and __ (AEB-2), I began with the current annualized dividend as of March 1, 2016 for each proxy group company. In the first stage of the model, the current annualized dividend is escalated based on the average of the three-to five-year earnings growth estimates reported by First Call,

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[35] *See generally* Case 10-E-0362, Case 06-E-1433, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc., for Electric Service*, Case 08-E-0539, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*.

Zacks, and Value Line. For the third stage of the model, I relied on long-term projected growth in Gross Domestic Product ("GDP"). The second stage growth rate is a transition from the first stage growth rate to the long-term growth rate on a geometric average basis.

Q. WHY DO YOU BELIEVE THAT EARNINGS GROWTH RATES ARE THE APPROPRIATE GROWTH RATES TO BE RELIED ON IN THE DCF MODEL?

A. Earnings are the fundamental driver of a company's ability to pay dividends; therefore, earnings growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to reflect accurately investor perceptions of a company's growth prospects.

Q. IS THERE SUPPORT FOR THE USE OF ANALYSTS' EARNINGS GROWTH ESTIMATES IN THE DCF MODEL?

A. Yes, there is significant academic support for the use of analyst growth rates. In addition, the majority of the data that are publicly available to investors sets forth analysts' projections of earnings growth rates.

1 **Q. PLEASE SUMMARIZE THE ACADEMIC RESEARCH ON GROWTH RATES AND STOCK**
2 **VALUATION.**

3 A. The relationship between various growth rates and stock valuation metrics has been
4 the subject of much academic research. Many published articles specifically
5 support the use of analysts' earnings growth projections in the DCF model in
6 general, as well as for a method of calculating the expected market risk premium in
7 particular. Dr. Robert Harris, for example, demonstrated that financial analysts'
8 earnings forecasts (referred to in the article as "FAF") in a constant growth DCF
9 formula are an appropriate method of calculating the expected market risk
10 premium.[36] Dr. Harris made the following observations:

11 […] a growing body of knowledge shows that analysts'
12 earnings forecasts are indeed reflected in stock prices. Such
13 studies typically employ a consensus measure of FAF
14 calculated as a simple average of forecasts by individual
15 analysts.[37]

16 *****

17 Given the demonstrated relationship of FAF to equity prices
18 and the direct theoretical appeal of expectational data, it is no
19 surprise that FAF have been used in conjunction with DCF
20 models to estimate equity return requirements.[38]

21 Professors Carleton and Vander Weide also performed a study to determine
22 whether projected earnings growth rates are superior to historical measures of

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36 Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, Spring 1986 at p. 66.
37 *Id* at 59.
38 *Id* at 60.

growth in the implementation of the DCF model.[39] Although the purpose of that study was to "investigate what growth expectation is embodied in the firm's current stock price,"[40] the authors clearly indicate the importance of earnings projections in the context of the DCF model. Professors Carleton and Vander Weide concluded that:

> […] our studies affirm the superiority of analysts' forecasts over simple historical growth extrapolations in the stock price formation process. Indirectly, this finding lends support to the use of valuation models whose input includes expected growth rates.[41]

Similarly, Harris and Marston presented "estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts."[42] In addition to other findings, Harris and Marston reported that,

> […] in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in estimating return requirements provides reasonable empirical results that can be useful in practical applications.[43]

The Carleton and Vander Weide study was updated to determine whether the finding that analysts' earnings growth forecasts are relevant in the stock valuation process still holds. The results of that updated study continued to demonstrate the

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39 James H. Vander Weide, Willard T. Carleton, *Investor growth expectations: Analysts vs. history,* The Journal of Portfolio Management, Spring 1988.

40 *Id* at 78.

41 *Id* at 82.

42 Robert S. Harris, Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992.

43 *Id* at 63.

1 importance of analysts' earnings forecasts, including the application of those
2 forecasts to utility companies.[44] Similarly, Brigham, Shome and Vinson noted that
3 "evidence in the current literature indicates that (1) analysts' forecasts are superior
4 to forecasts based solely on time series data; and (2) investors do rely on analysts'
5 forecasts."[45]

6 **Q. WHAT IS YOUR OPINION OF THE COMMISSION'S HISTORICAL RELIANCE ON**
7 **DIVIDEND PER SHARE GROWTH RATES DURING THE INITIAL FIVE-YEAR TERM OF**
8 **ITS TWO STAGE DCF MODEL?**

9 A. There are several reasons why sole reliance on Value Line projections of dividend
10 per share growth is not appropriate. First, as discussed above, the use of only
11 dividend growth rates ignores the academic research demonstrating that earnings
12 growth rates are most relevant in stock price valuation.[46] Second, projections of
13 dividend growth, which would not include growth in retained earnings, only
14 measure a portion of the growth experienced by the company. Therefore,
15 projections of earnings growth are more complete estimates of total company
16 growth than projected dividend growth rates. Finally, Value Line's 4-6 year
17 projections are not consensus estimates, but reflect the viewpoint of a single

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44 Advanced Research Center, *Investor Growth Expectations*, Summer, 2004.

45 *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985.

46 The Recommended Decision ("RD") in the GFP indicates that the Telecommunications Group, which included Commission Staff, supported the use of earnings per share growth in the DCF models employed to estimate the ROE (RD at 9).

1 analyst. Therefore, the Commission's models, which have historically relied only
2 on projected dividend per share growth rates from Value Line, are limited in that
3 they reflect the growth expectations of a single analyst in the first stage of the
4 model. In contrast, there are several consensus estimates of projected earnings per
5 share growth rates that are publicly available and widely used by investors,
6 including Zacks Investment Research and Thomson Reuters (published on Yahoo
7 Finance). Each of these consensus forecasts considers the growth expectations for
8 each company based on the expectations of multiple analysts.

9 **Q. HOW DID YOU CALCULATE THE LONG-TERM GDP GROWTH RATE?**

10 A. As shown in Exhibit __ (AEB-3), the long-term growth rate of 5.36 percent is based
11 on the real GDP growth rate of 3.24 percent from 1929 through 2015,[47] and a
12 projected inflation rate of 2.05 percent. The rate of inflation of 2.05 percent is based
13 on three measures: (1) the average long-term projected growth rate in the
14 Consumer Price Index ("CPI") of 2.20 percent, as reported by Blue Chip Financial
15 Forecasts;[48] (2) the compound annual growth rate of the CPI for all urban consumers
16 for 2025-2040 of 2.11 percent as projected by the Energy Information
17 Administration ("EIA") in the Annual Energy Outlook 2015; and (3) the compound

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47 U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts Tables, Table 1.1.6, February 26, 2016.

48 Blue Chip Financial Forecasts, Vol. 34, No.12, December 1, 2015, at 14.

1 annual growth rate of the GDP chain-type price index for 2025-2040 of 1.85
2 percent, also reported by the EIA.[49]

3 **Q. WHY IS THE LONG-TERM GDP GROWTH RATE A REASONABLE ESTIMATE OF**
4 **LONG-TERM GROWTH IN YOUR MULTI-STAGE DCF MODEL?**

5 A. In regulatory proceedings, long-term estimates of GDP growth are commonly used
6 as a proxy for the long-term growth in proxy group company dividends in multi-
7 stage DCF analyses. That application is based on the common theoretical
8 assumption that, over the long-run, all companies in the economy will tend to grow
9 at the same constant rate. That assumption is designed to address the uncertainty
10 associated with estimating individual company growth rates over very long time
11 horizons and is not meant to act as a prediction that company growth rates in the
12 economy will indeed converge in practice over any given period.

13 **Q. IS YOUR CALCULATION OF GDP GROWTH CONSISTENT WITH ANALYSTS'**
14 **ESTIMATES OF LONG-TERM GDP GROWTH?**

15 A. Yes. Investors understand that the U.S. economy goes through cycles of growth
16 and contraction. Therefore, it is appropriate to consider the longest time period
17 possible to measure historical real growth in GDP. This view is consistent with
18 Morningstar's explanation about measuring GDP growth:

19 > Growth in real GDP (with only a few exceptions) has been
20 > reasonably stable over time; therefore, its historical
21 > performance is a good estimate of expected long-term future

[49] U.S. Energy Information Administration, Annual Energy Outlook 2015, Table 20.

> performance. By combining the inflation estimate with the real growth rate estimate, a long-term estimate of nominal growth is formed.[50]

Furthermore, Morningstar supports the use of a long-term historical data:

> The 87-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect "unusual" events to occur from time to time, and their return expectations reflect this.[51]

Q. HOW DOES YOUR ESTIMATE OF LONG-TERM GDP GROWTH COMPARE WITH INVESTOR EXPECTATIONS OF LONG-TERM UTILITY INDUSTRY GROWTH RATES?

A. The Commission has traditionally relied on Bank of America Merrill Lynch's ("BAML") market return calculations in estimating a company's ROE using the CAPM. Exhibit __ (AEB-4) includes the relevant pages from the BAML *Quantitative Profiles* reports for December 2015 through February 2016. BAML derives the Implied Return through the use of a multi-stage Dividend Discount Model ("DDM").[52] As shown in Exhibit __ (AEB-4), the December, January and

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[50] Ibbotson and Associates, Stocks, Bonds, Bills and Inflation, 1926-2012, 2013 Valuation Yearbook, at 52.

[51] Ibbotson and Associates, Stocks, Bonds, Bills and Inflation, 1926-2012, 2013 Valuation Yearbook, at 59.

[52] Bank of America Merrill Lynch, *Quantitative Profiles,* February 11, 2016 at 9.

1 February Implied Returns for the utility industry were 10.10 percent, 9.90 percent
2 and 9.70 percent, respectively, which produces an average Implied Return of
3 approximately 9.90 percent.[53] For those same months, the dividend yield for the
4 utility industry was 3.9 percent.[54] Because the total return consists of capital
5 appreciation (*i.e.*, growth) and dividend yield, that data imply a utility growth rate
6 of approximately 6.00 percent, which is considerably higher than the long-term
7 growth estimate of 5.36 percent used in my multi-stage DCF analysis.

8 **Q. HOW DOES YOUR ESTIMATE OF LONG-TERM GROWTH DIFFER FROM THE**
9 **ESTIMATE THAT THE COMMISSION HAS TRADITIONALLY RELIED ON?**

10 A. The final stages of both the two-stage DCF model that the Commission has relied
11 on and my multi-stage DCF model extend into the future indefinitely. My long-
12 term growth estimate reflects investors' long-term growth expectations for the
13 period from 2025 through 2040. Therefore, the third stage of my multi-stage DCF
14 model reflects investor growth expectations beginning in the first year of the third
15 stage of the model. In contrast, the growth estimate for the two-stage model that
16 the Commission has typically relied on is based on short-term growth rate forecasts.
17 The use of the sustainable growth rate, calculated using Value Line's published
18 projections, provides an estimate of growth four- to six-years in the future. As a

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53 Bank of America Merrill Lynch, *Quantitative Profiles,* December 21, 2015 at 56. Bank of America Merrill Lynch, *Quantitative Profiles,* January 22, 2016 at 57. Bank of America Merrill Lynch, *Quantitative Profiles,* February 11, 2016 at 57.

54 *Id*.

1 result, the use of the sustainable growth rate in perpetuity in the second stage of a
2 two-stage DCF model does not provide a long-run estimate of growth. Rather, the
3 use of the sustainable growth rate assumes that the short-term estimate for the four-
4 to six-year period from the Value Line report date is sustained in perpetuity.
5 In contrast, the long-term growth rate in my multi-stage DCF analyses reflects both
6 economic forecasts and market-derived projections of inflation over the longest
7 available time period (30 or more years). Those estimates of long-term inflation
8 expectations are combined with the long-term average historical real GDP growth
9 rate to calculate an expected nominal GDP growth rate. Consequently, the long-
10 term growth estimate used in my multi-stage DCF model represents investors' and
11 economists' views of nominal long-term GDP growth well beyond the time horizon
12 reflected in the four- to six-year Value Line sustainable growth estimate relied on
13 by the Commission in prior cases.

14 **Q. DOES THE USE OF VALUE LINE DATA TO DEVELOP THE SUSTAINABLE GROWTH**
15 **RATE ADDRESS CONCERNS ABOUT GROWTH RATE BIAS?**

16 A. No. The sustainable growth rate is the sum of retention growth plus an SV factor,[55]
17 calculated using Value Line data. As such, the sustainable growth rate estimate

[55] Retention growth is the product of the expected earned ROE and the retention ratio (one minus the dividend payout ratio). The SV factor employs an estimate of the market-to-book ratio and the expected expansion rate of outstanding shares of common stock in the future.

that has been relied on by the Commission is based on a single analyst's viewpoint of a company's projected 4-6 year growth prospects.

Q. ARE THERE OTHER PROBLEMS WITH THE USE OF THE SUSTAINABLE GROWTH RATE AS AN ESTIMATE OF LONG-TERM GROWTH?

A. Yes. The sustainable growth rate calculation uses a very narrowly defined set of short-term projections. The sustainable growth rate, developed using Value Line data, relies on the following assumptions: (1) projected dividends for year 2; (2) projected dividends for years 4-6; (3) projected earnings for years 4-6; (4) projected book value for year 2; (5) projected book value for years 4-6; (6) current estimate of actual outstanding shares of stock; (7) projected shares of outstanding stock for years 4-6; and (8) current three-month stock price. Each of these assumptions is estimated at most for six years into the future. As a result, the sustainable growth rate, which is applied over the long-term in the Commission's two-stage model, does not consider any actual long-term forecasts for the specific company or the economy as a whole which is a limitation in the Commission's model.

Q. WHAT IS YOUR CONCLUSION REGARDING THE METHODOLOGY TYPICALLY RELIED ON BY THE COMMISSION TO ESTIMATE THE SUSTAINABLE GROWTH RATE?

A. There are several reasons why the Commission's sustainable growth rate should not be relied on in the two-stage DCF model. First, the sustainable growth rate is not a long-term measure of growth and as such should not be applied in perpetuity

in the second stage of the model. Second, the exclusive use of Value Line data, which is a single analyst's viewpoint, to establish the sustainable growth rate assumes that investors do not consider any of the other financial information that is widely available when establishing future dividend expectations. Finally, the Commission's sustainable growth rate methodology implicitly assumes that investors establish long-term growth expectations based entirely on short-term, company-specific projections. It is unreasonable to conclude that investors would ignore the expectations of long-term macroeconomic growth in establishing the long-term growth estimates for a natural gas distribution utility or any other company.

Q. HAVE OTHER REGULATORY COMMISSIONS RECENTLY RECONSIDERED THE USE OF THE SUSTAINABLE GROWTH RATES IN THE ROE ESTIMATION METHODOLOGY?

A. Yes. The FERC's long-standing methodology for setting the ROE in utility proceedings was to rely on a single stage DCF model that used two estimates of short-term growth: 1) analysts' estimates of earnings growth, as published by IBES and 2) the sustainable growth rate, calculated using the $b*r + s*v$ components that are used by this Commission. The FERC acknowledged that the sustainable growth rate is not a measure of long-term growth, but is another estimate of short-term growth similar to analysts' earnings projections.

In Opinion No. 531, the FERC determined that it was appropriate to move from a constant growth DCF methodology to a two-stage DCF model for public utility rate

1 cases. In moving to the two-stage DCF, FERC now relies on analysts' estimates of
2 earnings growth in the short-term and a long-term GDP growth rate as the measure
3 of growth in the second stage. The FERC's two stage model does not rely on a
4 sustainable growth calculation.[56]

5 **Q. WHAT ARE THE RESULTS OF YOUR DCF ANALYSES?**

6 A. As shown in Exhibits __ (AEB-1) and __ (AEB-2), the multi-stage DCF analysis
7 based on a three-month average stock price and a range of near-term growth rate
8 assumptions produces a range of 9.12 percent to 9.55 percent, with a mean ROE of
9 9.30 percent for the Combined Utility Proxy Group, and a range of 8.77 percent to
10 9.37 percent with a mean of 9.02 percent for the Natural Gas Proxy Group.

11 **Q. DOES THE DCF MODEL ADDRESS YOUR CONCERN ABOUT UTILITY VALUATIONS?**

12 A. No, it does not. While the multi-stage DCF model provides for changes in growth
13 over time, it does not address the very high current P/E ratios for utility stocks and
14 the effects of those high valuations on the dividend yield in the DCF model.

15 **Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE RESULTS OF THE DCF MODEL?**

16 A. The results of the multi-stage DCF model are currently influenced by the high
17 valuations on utility stocks. As discussed previously, one primary assumption of
18 the DCF model is the dividend yield. That assumption is heavily influenced by the
19 market price of utility stocks. To the extent that these stock prices are inflated, as

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[56] Opinion No. 531 147 FERC ¶ 61,234 (June 19, 2014).

is suggested by the high P/E ratios and analysts' expectation that those P/E ratios are not sustainable in the short term, it is important to consider the results of the DCF model with caution. Therefore, I have applied equal weighting to the results of the DCF and CAPM.

Q. HAVE YOU QUANTIFIED THE EFFECT THAT THE MARKET'S EXPECTATION FOR HIGHER INTEREST RATES HAS ON THE DIVIDEND YIELD COMPONENT OF THE DCF MODEL?

A. Yes, I have. Using Value Line projections for dividends and share prices for the period from 2018-2020, I have calculated the projected dividend yields for the companies in my Combined Utility and Natural Gas Proxy Groups. As shown in Exhibits __ (AEB-5) and (AEB-6), my analysis demonstrates that using the projected dividend yield in the mean multi-stage DCF model results in a 52 basis point increase (*i.e.*, 9.82 percent vs. 9.30 percent shown in Exhibit__(AEB-1)) in the return on equity for the Combined Utility Proxy Group and a 41 basis point increase (i.e., 9.43 percent vs. 9.02 percent shown in Exhibit ___(AEB-2)) in the return on equity for the Natural Gas Proxy Group.

1 **B. CAPITAL ASSET PRICING MODEL**

2 **Q. PLEASE BRIEFLY DESCRIBE THE CAPITAL ASSET PRICING MODEL.**

3 A. The CAPM is a risk premium approach that estimates the market cost of equity for
4 a given security as a function of a risk-free return plus a risk premium (to
5 compensate investors for the non-diversifiable or "systematic" risk of that security).
6 As shown in Equation [2], the CAPM is defined by four components:

7 $$k_e = r_f + \beta(r_m - r_f) \qquad [2]$$

8 where:

9 k_e = the required market ROE

10 β = Beta coefficient of an individual security

11 r_f = the risk-free rate of return

12 r_m = the required return on the market as a whole

13 In this specification, the term (r_m – r_f) represents the market risk premium.
14 According to the theory underlying the CAPM, investors should be concerned only
15 with systematic or non-diversifiable risk because unsystematic risk can be
16 diversified away. Non-diversifiable risk is measured by the Beta coefficient, which
17 is defined as:

18 $$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \qquad [3]$$

19 The variance of the market return, noted in Equation [3], is a measure of the
20 uncertainty of the general market, and the covariance between the return on a

1 specific security and the market reflects the extent to which the return on that
2 security will respond to a given change in the market return.

3 **Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR CAPM?**

4 A. I used three estimates of the yield on Treasury bonds: (1) the current three-month
5 average yield on 30-year Treasury bonds (2.82 percent);[57] (2) the projected 30-year
6 Treasury yield for 2016-2017 (3.35 percent);[58] and (3) the projected 30-year
7 Treasury yield for the period 2017-2021 (4.50 percent).[59] In determining the
8 security most relevant to the application of the CAPM, it is important to select the
9 term (or maturity) that best matches the life of the underlying investment. As noted
10 by Morningstar:

11 The traditional thinking regarding the time horizon of the
12 chosen Treasury security is that it should match the time
13 horizon of whatever is being valued… Note that the horizon is
14 a function of the investment, not the investor. If an investor
15 plans to hold stock in a company for only five years, the yield
16 on a five-year Treasury note would not be appropriate since the
17 company will continue to exist beyond those five years.[60]

18 Because utility companies represent long-duration investments, it is appropriate to
19 use yields on long-term Treasury bonds as the risk-free rate component of the
20 CAPM. In my view, the 30-year Treasury bond is the appropriate security for that
21 purpose. Because the cost of capital is intended to be forward-looking, it is

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57 Bloomberg Professional.
58 Aspen Publishers, Blue Chip Financial Forecasts, Vol. 35, No. 2 February 1, 2016, p. 2.
59 Aspen Publishers, Blue Chip Financial Forecasts, Vol. 34, No. 12 December 1, 2015, p. 14.
60 Morningstar Inc., Ibbotson SBBI 2013 Valuation Yearbook, at 44.

appropriate to consider projected measures of the market risk premium and interest rates. Furthermore, because interest rates are at historically low levels and are projected to increase in the near future, it is important to consider forward-looking estimates of the risk-free rate and the market risk premium in the CAPM analysis.

Q. PLEASE DESCRIBE THE FORWARD-LOOKING MARKET RISK PREMIUM USED IN YOUR CAPM.

A. The forward-looking market risk premium is based on the expected return on the S&P 500 Index less the 30-year Treasury bond yield. The expected return on the S&P 500 Index is calculated using a DCF model for all companies in the index based on market capitalization-weighted growth rates and dividend yields. The market risk premium implied by each of the three Treasury yields discussed above is used in the CAPM analysis.

Q. IS YOUR CALCULATION OF THE MARKET RISK PREMIUM CONSISTENT WITH THE METHODOLOGY RELIED UPON IN PREVIOUS CASES BEFORE THE COMMISSION?

A. Yes, it is. The Commission previously has relied upon the calculation of a projected market risk premium, based on the difference between the estimated forward-looking required market return for the S&P 500, as provided by BAML, and the risk-free rate.[61] As a practical matter, that approach is consistent with the Market

[61] *See e.g.,* 2011 O&R Rate Order, at 77.

1 DCF-derived forward-looking market risk premium estimate discussed above (*see*
2 *also* Exhibits __ (AEB-7) and __ (AEB-8).

3 **Q. WHAT BETA COEFFICIENT DID YOU USE IN YOUR CAPM?**

4 A. I considered the Beta coefficients reported by Bloomberg and Value Line for each
5 of the proxy group companies.

6 **Q. WHY DO YOU BELIEVE IT IS APPROPRIATE TO RELY ON TWO SOURCES OF BETA**
7 **COEFFICIENTS?**

8 A. While both Bloomberg and Value Line adjust their calculated (or "raw") Beta
9 coefficients to reflect the tendency of the Beta coefficient to regress to the market
10 mean of 1.00, Value Line calculates the Beta coefficient over a five-year period,
11 while Bloomberg's calculation is based on a two-year period. While a larger data
12 set is generally preferred from a statistical perspective, the Bloomberg Beta
13 coefficient is widely employed and more representative of the current market
14 environment. Therefore, there are benefits to including both measures of Beta in
15 the CAPM analysis.

16 **Q. DID YOU CONSIDER ANOTHER FORM OF THE CAPM IN YOUR ANALYSIS?**

17 A. Yes. In prior proceedings, the Commission has also relied upon the Zero-Beta
18 CAPM (the form of which is sometimes referred to as the "Empirical CAPM"[62]) in
19 estimating the cost of equity. The Zero-Beta CAPM calculates the product of the

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[62] *See e.g.,* Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 189.

adjusted Beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the Zero-Beta CAPM result, as noted in Equation [4] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [4]$$

where:

k_e = the required market ROE

β = Adjusted Beta coefficient of an individual security

r_f = the risk-free rate of return

r_m = the required return on the market as a whole

In essence, the Zero-Beta form of the CAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low Beta coefficients such as regulated utilities. In that regard, the Zero-Beta CAPM is not redundant to the use of adjusted Betas; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[63]

As with the CAPM, my application of the Zero-Beta CAPM uses the forward-

[63] *Id*. at 191.

1 looking market risk premium estimates, the three yields on 30-year Treasury
2 securities noted earlier as the risk-free rate, and the Bloomberg and Value Line Beta
3 coefficients. Exhibits __ (AEB-7) and __ (AEB-8) show the results of the CAPM
4 models for the Combined Utility and Natural Gas Proxy Groups. The traditional
5 CAPM results range from 9.19 percent to 11.22 percent. The Zero-Beta CAPM
6 results range from 10.23 percent to 11.76 percent. The range established by the
7 traditional CAPM and the Zero-Beta CAPM is 9.19 percent to 11.76 percent with
8 a mean of 10.65 percent.

9 **C. WEIGHTED AVERAGE RESULTS**

10 **Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSIS AND YOUR RECOMMENDED**
11 **ROE.**

12 A. As shown in Table 5, I have weighted the DCF and CAPM results equally, resulting
13 in an ROE range of 9.65 percent to 10.20 percent.

1 **Table 5: Weighted Average Analytical Results**

Natural Gas Proxy Group			
	Low	**Mean**	**High**
DCF	8.77%	9.02%	9.37%
Mean CAPM	10.52%	10.72%	10.98%
Mean ROE	9.65%	9.87%	10.18%
Combined Utility Proxy Group			
	Low	**Mean**	**High**
DCF	9.12%	9.30%	9.55%
Mean CAPM	10.38%	10.59%	10.85%
Mean ROE	9.75%	9.94%	10.20%

2

3 **Q. WHY ARE GFP AND THE RD A RELEVANT CONSIDERATION TODAY?**

4 A. The Commission opened the GFP to address several questions including; should
5 the Commission's use of an interest rate sensitive DCF approach to the cost of
6 equity be modified and what approaches could be substituted. Several parties were
7 involved and the resulting RD established a recommended framework from which
8 to begin to address the concerns raised in the process.

9 The RD recognized that the DCF methodology was especially sensitive to
10 fluctuations in interest rates and that the Commission had asked parties to address
11 the desirability of continuing to rely on that methodology. The RD also
12 acknowledged that there was nothing sacrosanct about the DCF analysis and that
13 all methods had benefits and shortcomings.[64] Finally, at the time of the GFP, the

[64] 1994 N.Y. PUC Lexis 141, 39.

1 Commission was concerned about consistency from company to company in the
2 rate of return calculation, noting that differences in returns should be based on
3 "discernible and explanatory differences among utilities."[65] It was also observed
4 that using a generic determination methodology would have the benefit of
5 enhancing consistency by eliminating variations in results due to noise in the data
6 or random measurement errors.[66] The RD also supported the use of multiple
7 methodologies in a generic ROE estimation methodology, noting that DCF-based
8 results are in no way superior to those obtained using other methods.[67] While the
9 RD recommended the 2/3 DCF and 1/3 CAPM weighting as an operating norm, it
10 left open consideration of alternative weightings and methodologies. This guidance
11 is consistent with the *Hope* decision, which indicates that the means of arriving at
12 a fair return are not controlling, only that the end result leads to just and reasonable
13 rates. The effect of current market conditions on the results of the ROE estimation
14 models require the careful review of the "operating norm" that has been relied on
15 by the Commission in the past to establish returns, and appropriate adjustments to
16 ensure fair and equitable treatment of regulated entities.

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65 *Id.* at 38.
66 *Id.* at 39.
67 1994 N.Y. PUC Lexis 141, 74.

1 **Q. WHAT WAS THE RATIONALE IN THE RD FOR THE WEIGHTING OF THE DCF AND**
2 **CAPM METHODOLOGIES?**
3 A. At the time of the RD, it does not appear that the Commission had a significant
4 amount of experience with CAPM results. The RD noted that the Commission had
5 historically used the CAPM method as a check on its DCF results, and was
6 somewhat undecided as to "how far the Commission should go in elevating the
7 status of CAPM."[68] The RD opted for a gradual transition towards CAPM,
8 ultimately settling on a 1/3 weighting, indicating that "proposals have simply not
9 shown that the CAPM should be raised all at once to parity with the DCF analysis
10 in the setting of returns on equity."[69] To the extent that this was a consideration in
11 the RD's weighting determination, the Commission's many years of experience
12 with the CAPM since that time provides a sound basis for altering the weighting of
13 the two ROE methodologies.
14 **Q. HOW HAVE THE RETURNS AUTHORIZED BY THIS COMMISSION CHANGED OVER**
15 **TIME?**
16 A. Chart 3 below provides the range of ROE's that were authorized for natural gas
17 distribution companies and electric utilities for each year from 1980 to 2015. The
18 average return authorized by this Commission is also noted for each year. Chart 3
19 demonstrates that for the period from 1980 – 1989 the Commission authorized

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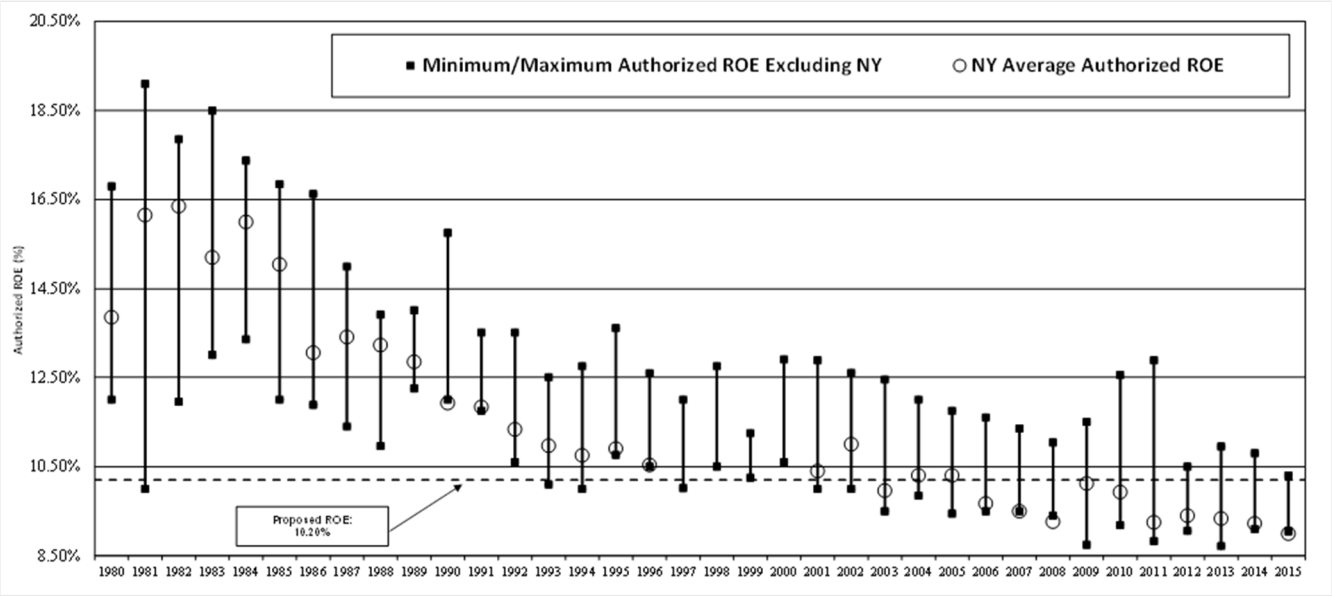
68 RD at 27.
69 *Id*.

ROEs were within the range established by other jurisdictions' ROEs. This suggests that an alternative weighting of the DCF and CAPM results is appropriate to achieve the Commission's intended results.

Chart 3: Comparison of New York Authorized Returns and Authorized Returns[70]



In 1990-1991, just prior to the GFP, the Commission's authorized ROEs had fallen to the bottom of the range established by other state jurisdictions. Weightings on the DCF and CAPM results that were proposed in the RD provided for more stable ROEs, the Commission's authorized ROEs since 1994 (the date of the RD) have either set the low end of the range of returns nationally or been at the low end of that range.

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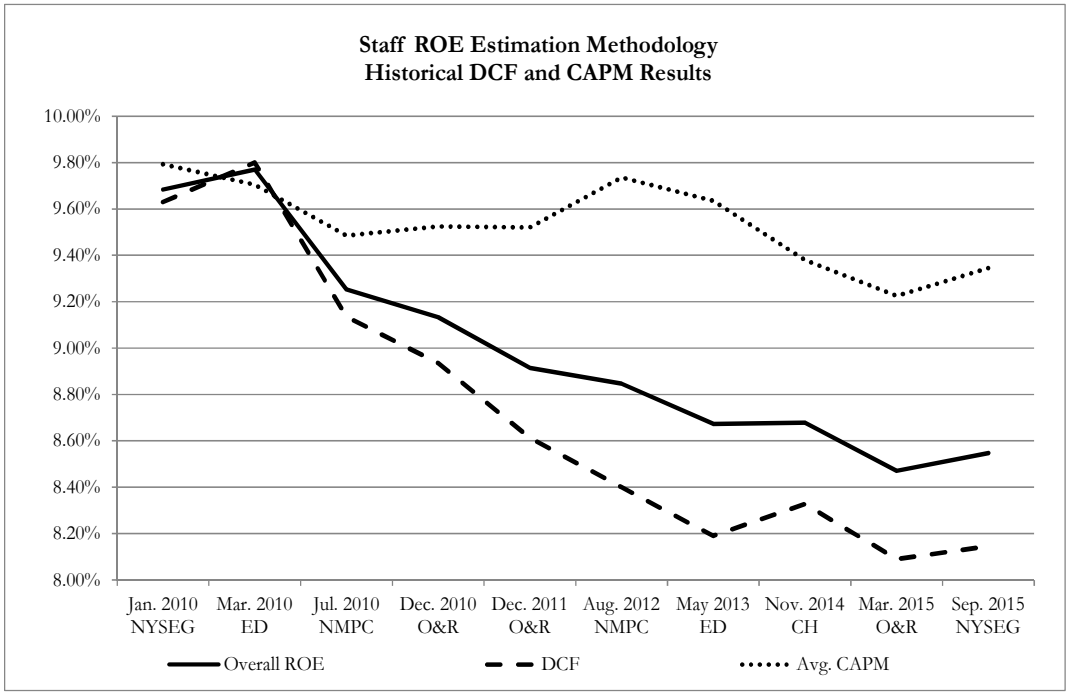
70 From 1997-2000, the Commission did not issue an order in a rate case where traditional rate case parameters such as the cost of equity were m specifically determined by the commission.

Q. HOW HAVE CURRENT MARKET CONDITIONS INFLUENCED YOUR RECOMMENDATION TO MOVE TO EQUAL WEIGHTING FOR THE CAPM AND THE DCF RESULTS?

A. The RD in the GFP indicates that DCF results at the time the Commission initiated its inquiry were approximately 100 basis points less than the ROE obtained with other approaches. The situation today is more acute, with the DCF estimate more than 110 basis points below the CAPM estimate. Thus, current market conditions demonstrate that the DCF model is susceptible to interest rate and market volatility and produces results today that are significantly lower than the results derived from the CAPM and other risk-premium methodologies. As shown in Chart 4, using the Commission Staff analyses prepared over the past five years, the DCF results have ranged from 8.09 percent to 9.80 percent, while the average CAPM results have been in the range of 9.23 percent to 9.79 percent. In contrast, the results of the CAPM and Zero-Beta CAPM have been much more stable during market conditions over the past five years, indicating a systemic problem with the DCF.

Chart 4: Staff Estimation for NY utilities 2010-2016



Q. HAVE ANALYSTS COMMENTED ON THE EFFECT OF CURRENT MARKET CONDITIONS ON THE VALUE OF UTILITY STOCKS?

A. Yes. As discussed previously, Value Line indicated that utility stock prices may be trading at the high end of the three-to-five year target range and noted the market risks associated with the purchase of dividend-paying stocks. The combination of high prices for utility stocks today and the effect of rising interest rates on utility stock prices going forward likely results in an underestimation of the cost of equity using the DCF model.

1 **Q. PLEASE SUMMARIZE YOUR CONCLUSION REGARDING THE RELATIVE WEIGHTING**
2 **OF THE CAPM AND DCF RESULTS.**
3 A. In the early 1990s the Commission recognized that market conditions had affected
4 the results of the DCF model and through the opening of the GFP, sought alternative
5 methodologies to inform their judgment in setting a reasonable ROE for regulated
6 utilities in New York that was not wholly reliant on the DCF. Throughout the GFP,
7 many alternatives were considered and the benefits and shortcomings of each
8 methodology were identified. The RD summarizes that process and demonstrates
9 that there was no clear preference for the DCF methodology given its volatile
10 history. While the RD proposed the 2/3 weighting on the DCF, the weightings and
11 methodologies used to estimate the ROE were left open for additional consideration
12 in future rate proceedings. Since then, the Commission has employed the CAPM
13 as one component of the formula used to develop ROE estimates. There does not
14 appear to be any reason to infer that the Commission has less confidence in the
15 results of the CAPM than those of the DCF.
16 The concerns that warranted the Commission's GFP inquiry and the subsequent RD
17 in the early 1990s exist today with volatile DCF results that are considerably below
18 the results of other methodologies, the CAPM in particular. To the extent that
19 dividend-paying stocks are "expensively priced" today and could correct to lower
20 levels in the period that rates would be in effect, the DCF model is likely to
21 underestimate the cost of equity. Therefore, it is appropriate for the Commission

to reexamine how the market has influenced the assumptions used in the ROE estimation models and to consider recalibrating the weightings in the formula that it has used since the GFP to produce ROE results that are consistent with the *Hope* and *Bluefield* standards. One reasonable approach is to apply equal weighting to the DCF and CAPM methodologies when setting the ROE for Distribution.

VII. REGULATORY AND BUSINESS RISKS

A. NEW YORK ALLOWED ROES AND WEIGHTED ROES

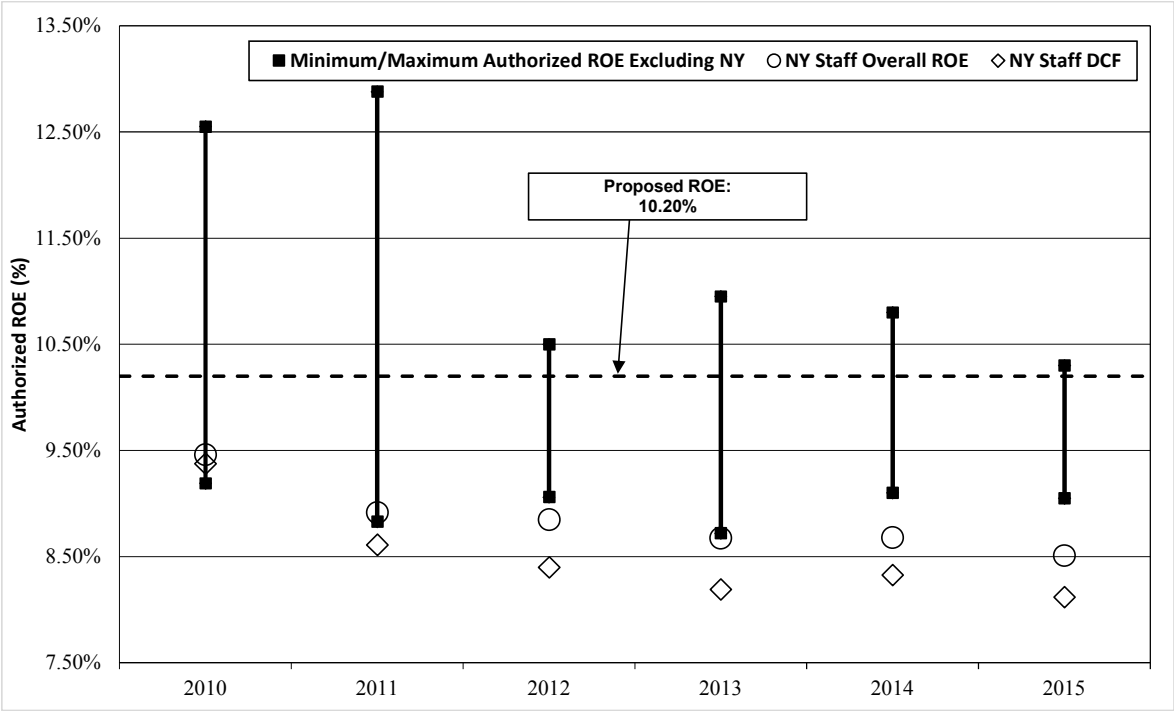
Q. HOW DO THE RETURNS THAT RESULT FROM THE MODEL THAT THE COMMISSION HAS TRADITIONALLY RELIED ON COMPARE WITH AUTHORIZED RETURNS IN OTHER JURISDICTIONS?

A. Over time, the results of the two-stage DCF model that the Commission has traditionally relied on have significantly reduced the overall authorized ROE for utility operations in New York. Chart 5 shows the range of authorized returns for utilities in other jurisdictions[71] since January 2010, the results of New York's DCF model, and the overall ROE that resulted from New York's DCF and CAPM models. As shown in Chart 5, the results of New York's DCF model have been below the minimum authorized return in other jurisdictions in all five years since 2010, while the result of New York's DCF/CAPM weighting methodology resulted

[71] The average authorized returns exclude the returns authorized by the Commission.

in overall returns that were either below or very close to the minimum authorized return in other jurisdictions.

Chart 5: Comparison of New York ROE model results and Authorized Returns



Q. WHAT DOES THIS INFORMATION INDICATE REGARDING THE LEVEL OF ALLOWED ROES IN NEW YORK RELATIVE TO THE RETURNS AUTHORIZED IN OTHER JURISDICTIONS?

A. Over the past several years, the Commission's authorized ROEs have been well below the national average authorized return on equity. While applying an equal weighting of DCF and CAPM results improves the results of the New York model, the New York model would still underestimate the return on equity as compared with the national average authorized return. Furthermore, as discussed in Section

1 VIII of my Testimony, combining a below average authorized ROE resulting from
2 the Commission's historical weighting with a ratemaking equity ratio at 48 percent
3 results in a weighted average return on equity for New York utilities that is well
4 below the national average over the last several years. I am aware that, in the past,
5 the Commission justified the relatively lower ROEs that it was awarding vis-à-vis
6 other jurisdictions based on New York's inclination to use innovative regulatory
7 mechanisms such as future test years, revenue decoupling and other automatic
8 adjustment clauses. While this may have differentiated the Commission from other
9 jurisdictions in the past, it is no longer the case. For example, a 2013 study by the
10 Brattle Group found the following:

11 • Revenue Stabilization. These mechanisms, which include conservation
12 adjustments and decoupling mechanisms, adjust base revenues, without
13 addressing costs, between rate cases. They remove the conflict in the utility
14 promoting efficiency and deal with falling sales from various sources. 27
15 states for electricity and 31 states for natural gas delivery participate in this
16 kind of alternative regulation.[72]
17 • Comprehensive Alternative Ratemaking and Timely Recovery. These are
18 ways to move beyond the general rate cases of cost of service regulation

[72] "Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of the 21st Century the 21st Century," that was prepared for the National Association of Water Companies, (September 30, 2013), at 2.

and bring into rates future costs from investment projects and other sources. 34 states for electricity and 18 states for natural gas delivery have some form of comprehensive alternative regulation. For water, 4 states have been identified as having some form of comprehensive alternative regulation. In addition a number of states have the positive feature of a future or partially future test year in the traditional general rate case, which is a related, traditional policy that is surveyed, but not included in the count of states above.[73]

- Alternative Ratemaking for Capital Expenditures. Distribution System Improvement Charge ("DSIC") and Capital Expenditure (Capex) Riders are innovative means to collect the costs of standard investments to maintain the integrity of distribution systems. 17 states for electricity and 25 states for natural gas delivery have at least one kind of this alternative regulation. For Water, 15 states have been identified as having these policies.[74]

I recognize that New York may have been an early adopter of these types of revenue stability and cost recovery mechanisms, and that in those years, regulation in New York may have resulted in lower business risk for utilities as compared to other state jurisdictions. However, many commissions have now implemented similar

[73] Ibid at 2-3.
[74] Ibid at 3.

1 programs. Therefore, the regulatory treatment in New York is generally
2 comparable with other jurisdictions and does not justify a lower ROE.

3 **B. REGULATORY RISKS**

4 **Q. PLEASE EXPLAIN HOW THE REGULATORY FRAMEWORK AFFECTS INVESTORS'**
5 **RISK ASSESSMENTS.**

6 A. The ratemaking process is premised on the principle that, for investors and
7 companies to commit the capital needed to provide safe and reliable utility services,
8 the subject utility must have the opportunity to recover invested capital and the
9 market-required return on such capital. Regulatory commissions recognize that
10 because utility operations are capital intensive, regulatory decisions should enable
11 the utility to attract capital at reasonable terms, thereby balancing the long-term
12 interests of investors and customers. In that respect, the regulatory framework in
13 which a utility operates is one of the most important factors considered in both debt
14 and equity investors' risk assessments.

15 Because investors have many investment alternatives, even within a given market
16 sector, the Company's authorized return must be adequate on a relative basis to
17 ensure its ability to attract capital under a variety of economic and financial market
18 conditions. From the perspective of debt investors, the authorized return should
19 enable the Company to generate the cash flow needed to meet its near-term
20 financial obligations, make the capital investments needed to maintain and expand

its system, and maintain sufficient levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally-generated funds, but also from efficient access to capital markets.

From the perspective of equity investors, the authorized return must be adequate to provide a risk-comparable return on the equity portion of the Company's capital investments. Because equity investors are the residual claimants on the Company's cash flows (i.e., debt interest must be paid prior to any equity dividends), equity investors are particularly concerned with the regulatory framework in which a utility operates and its effect on future earnings and cash flows.

Rating Agency Perspective on Regulatory Risk

Q. HOW DO CREDIT RATING AGENCIES CONSIDER THE REGULATORY FRAMEWORK IN ESTABLISHING A COMPANY'S CREDIT RATING?

A. S&P and Moody's both consider the overall regulatory framework in establishing credit ratings. In particular, Moody's establishes credit ratings based on four key factors:

1 **Table 6: Moody's Rating Factors**

Factor	Weighting
Regulatory Framework	25%
Ability to Recover Costs and Earn Returns	25%
Diversification	10%
Financial Strength	40%
Total	100%

2

3 Two of these factors (*i.e.*, regulatory framework and the ability to recover costs and
4 earn returns) are based on the regulatory environment such that 50% of Moody's
5 overall assessment of business and financial risk for regulated utilities is based upon
6 the regulatory environment.[75] Moody's further subdivides the first two factors,
7 regulatory framework and the ability to recover costs and earn authorized returns,
8 into sub-factors to help "provide more granularity and transparency on the overall
9 regulatory environment, which is the most important consideration for this
10 sector."[76]

11 With respect to the regulatory framework, Moody's looks for transparency,
12 predictability, and supportiveness of regulatory commissions.[77] For the second
13 factor, ability to recover costs and earn returns, Moody's evaluates the regulatory

[75] Moody's Investor Service, Rating Methodology, Regulated Electric and Gas Utilities, December 23, 2013, at 6.
[76] *Id.* at 3.
[77] *Id.* at 9-10.

elements that directly affect the ability of the utility to generate cash flow and service its debt over time.[78] Moody's views the ability to recover costs on a timely basis and to attract debt and equity capital as crucial credit considerations noting that "[t]he inability to recover costs…has been one of the greatest drivers of financial stress in this sector."[79] This is particularly true as utilities are often cash flow negative due to large capital expenditures, so any lack of timely recovery or sufficiency of rates can strain access to capital markets.

S&P has also identified the regulatory environment as an important factor, stating, "we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influence credit quality the most."[80]

Q. HOW DOES THE REGULATORY ENVIRONMENT IN WHICH A UTILITY OPERATES AFFECT ITS ACCESS TO AND COST OF CAPITAL?

A. The proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. Moody's has highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, stating that "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including

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78 *Id.* at 15.

79 *Id*.

80 Standard & Poor's, *Assessing U.S. Utility Regulatory Environments*, March 11, 2010, at 2.

1 the setting of rates), as well as the predictability and consistency of decision-making
2 provided by that foundation."[81]
3 *Regulatory Rankings Analysis*
4 **Q. HAVE YOU CONDUCTED ANY ANALYSIS OF INVESTORS' PERCEPTIONS OF THE**
5 **REGULATORY FRAMEWORK IN WHICH THE COMPANY OPERATES RELATIVE TO**
6 **THE PROXY GROUP COMPANIES?**
7 A. Yes. To assess investors' view of the Company's regulatory framework, I
8 considered three different rankings: (1) the S&P business and financial rankings;
9 (2) the Regulatory Research Associates ("RRA") ranking of regulatory
10 jurisdictions; and (3) S&P's ranking of the credit supportiveness of regulatory
11 jurisdictions.
12 S&P ranks the business profile on a six-tier scale from excellent ("1") to vulnerable
13 ("6") and the financial profile on a similar scale, from minimal ("1") to highly
14 leveraged ("6"). I applied that numeric ranking system to the proxy group
15 companies. As shown in Exhibit __ (AEB-9), NFG's business profile ranking was
16 satisfactory ("3"), which is below the proxy group average ranking which was
17 excellent ("1.19"). Regarding the financial profile rankings, Distribution's ranking
18 was significant ("4"), again below the proxy group average ranking which was
19 intermediate ("3.39").

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[81] *Id.*

1 **Q. PLEASE EXPLAIN HOW YOU USED THE RRA RATINGS TO COMPARE THE**
2 **REGULATORY JURISDICTIONS OF THE PROXY COMPANIES WITH THE COMPANY'S**
3 **REGULATORY JURISDICTION.**
4 A. RRA assigns a ranking for each regulatory jurisdiction from "Above Average/1" to
5 "Below Average/3," with nine total rankings between these categories. I applied a
6 similar numeric ranking system to the RRA rankings with "Above Average/1"
7 assigned the highest ranking ("9") and "Below Average/3" assigned the lowest
8 ranking ("1"). As shown on Exhibit __ (AEB-10), the New York jurisdictional
9 ranking ("5.0") was generally consistent with the proxy group average numeric
10 ranking ("5.26") from RRA.
11 **Q. HOW DID YOU CONDUCT YOUR ANALYSIS OF THE S&P CREDIT SUPPORTIVENESS?**
12 A. For credit supportiveness, S&P classifies each regulatory jurisdiction into five
13 categories that range from "Strong" to "Weak." Within each category, regulatory
14 jurisdictions are ranked according to their credit supportiveness from most credit
15 supportive to least credit supportive. For purposes of my analysis, I assigned a
16 numerical ranking to each jurisdiction ranked by S&P, from most credit supportive
17 ("1") to least credit supportive ("53"). As shown in Exhibit __ (AEB-11), the proxy
18 group average ranking was 25.57, which would be classified as Strong/Adequate
19 and rank slightly above average for credit supportiveness, while the New York
20 jurisdictional ranking was 34, which is below average in credit supportiveness.

1 **C. ALTERNATIVE RATE MECHANISMS**

2 **Q. HAVE YOU CONSIDERED THE EFFECT OF THE COMPANY'S REVENUE DECOUPLING**
3 **MECHANISM ON THE REQUIRED ROE?**

4 **A.** Yes, I have. Since the ROE recommendation is established for a company based
5 on its risk relative to the proxy group, it is necessary to consider how the
6 Company's overall risk profile compares to that of the Natural Gas proxy
7 companies. Therefore, I have reviewed the alternative rate mechanisms that have
8 been implemented by the Natural Gas proxy companies. Exhibit __ (AEB-12),
9 summarizes the alternative rate mechanisms that have been implemented by the
10 Natural Gas proxy companies. As shown in Exhibit __ (AEB-12), approximately
11 66.7 percent of the jurisdictions where the proxy companies operate have approved
12 some form of adjustment mechanism (i.e., formula rate plan, revenue decoupling
13 mechanism, straight fixed-variable rate design) that provides for the recovery of
14 prudently incurred costs between rate cases.

15 **Q. WHAT IS YOUR CONCLUSION REGARDING THE EFFECT OF THE COMPANY'S**
16 **DECOUPLING MECHANISM ON THE COST OF EQUITY FOR DISTRIBUTION IN NEW**
17 **YORK?**

18 **A.** Based on the analysis discussed above, my conclusion is that Distribution's revenue
19 decoupling mechanism does not reduce the Company's overall risk profile relative
20 to the Natural Gas proxy companies. Since many of the Natural Gas proxy
21 companies have implemented various alternative rate design mechanisms, these

1 companies currently have similar stabilization mechanisms as the Company.
2 Therefore, it is not necessary to adjust the authorized ROE for the Company's
3 revenue decoupling mechanism.

VIII. CAPITAL STRUCTURE

4 **Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED CAPITAL STRUCTURE.**

5 A. Distribution is requesting a 48.0 percent equity ratio for ratemaking purposes,
6 which is consistent with recent Commission precedent regarding the authorized
7 capital structure for utilities.[82]

8 **Q. HAVE YOU CONDUCTED ANY ANALYSIS OF DISTRIBUTION'S PROPOSED CAPITAL**
9 **STRUCTURE AS COMPARED WITH THE PROXY COMPANIES?**

10 A. Yes. I have reviewed the authorized capital structures of the regulated utility
11 operating companies in the Combined Utility and Natural Gas Proxy Groups for
12 the period from 2011 through 2014. As shown on Exhibits __ (AEB-13) and __
13 (AEB-14), the mean annual equity ratio of the proxy companies over that period
14 was 54.02 percent for the Combined Utility Group and 56.27 percent for the Natural

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[82] See generally Case 14-E-0493, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service*, Case 14-G-0494, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service*, Case 14-E-0318, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service*, Case 14-G-0319, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service*, and Case 15-E-005, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*.

Gas Proxy Group. It is important to note that over this period, on average, the equity ratios of the regulated operating subsidiaries of the proxy companies have been increasing. For example, the Natural Gas Proxy Group average equity ratio increased from 55.99 percent in 2011 to 56.87 percent in 2014.

Q. YOU HAVE SHOWN THAT BOOK EQUITY RATIOS FOR THE OPERATING SUBSIDIARIES OF THE PROXY GROUP HOLDING COMPANIES ARE GREATER THAN 48 PERCENT. ARE THE ACTUAL ALLOWED EQUITY RATIOS FOR THESE ENTITIES ALSO GREATER THAN 48 PERCENT?

A. Yes, they are. In fact allowed equity ratios for the natural gas and electric utility industry are greater than 48 percent. Exhibits __ (AEB-15) and __ (AEB-16) show that the average equity ratio most recently allowed is 51.01 percent for the companies in the Combined Utility Proxy Group and 52.42 percent for the companies in the Natural Gas Proxy Group.

Q. EXHIBITS __ (AEB-15) AND __ (AEB-16) INDICATE THAT THE 51.01 PERCENT AND 52.42 PERCENT EQUITY RATIOS ARE "ADJUSTED" EQUITY RATIOS. PLEASE EXPLAIN WHY IT IS NECESSARY TO EMPLOY ADJUSTED EQUITY RATIOS IN YOUR ANALYSIS.

A. Unlike most utility commissions that reflect cash flows produced by deferred taxes and other credits as a reduction to rate base, the utility commissions in Arkansas, Florida, Indiana, and Michigan do not reduce rate base but rather include these tax related items as zero or very low cost items in the allowed capital structure.

1 Inclusion of these additional low or no cost capital items will have the impact of
2 reducing both the equity and debt ratios used to establish the rate of return which,
3 in turn, produces results that are not comparable to allowed equity ratios in other
4 states. As such it is necessary to remove the zero cost items to put the debt and
5 equity ratio components of the allowed capital structure on a common basis with
6 all other utilities. Exhibits __ (AEB-15) and __ (AEB-16) show how I performed
7 this calculation to adjust equity ratios for the utilities operating in these four states.

8 **Q. WHAT DO YOU CONCLUDE FROM THE ANALYSES EXAMINING THE ALLOWED AND**
9 **BOOK EQUITY RATIOS OF THE COMPANIES IN THE PROXY GROUP?**

10 A. Distribution's request for a 48.0 percent equity ratio is conservative as compared
11 with the allowed and book equity ratios of the proxy companies. Utility operating
12 subsidiaries owned by holding companies with similar business characteristics as
13 Distribution have maintained average common equity ratios that are considerably
14 higher than the 48.0 percent equity ratio that the Company is requesting. These
15 higher proxy group equity ratios reflect a level of financial risk that is lower than
16 the financial risk implied by the proposed 48 percent equity ratio for Distribution.

17 **Q. DOES THE USE OF A 48.0 PERCENT EQUITY RATIO HAVE ANY IMPLICATIONS FOR**
18 **YOUR RECOMMENDATION CONCERNING THE COMPANY'S ROE?**

19 A. Yes. The average allowed and book equity ratio of the proxy companies is
20 significantly higher than 48.0 percent, which means that all else equal, the proxy
21 companies have lower financial risk than is implied by the 48.0 percent equity ratio

proposed by the Company. The use of a lower equity ratio than the proxy companies further supports an ROE at the high end of the range of results presented in Table 7 below.

IX. CONCLUSION AND RECOMMENDATION

Q. WHAT IS YOUR CONCLUSION REGARDING A FAIR RETURN ON BOOK EQUITY FOR DISTRIBUTION?

A. My recommended return on book equity considers the results of the DCF and CAPM models, summarized in Table 7, and the specific risks to which the Company is exposed. The range established based on an equal weighting of the DCF and CAPM results is between 9.65 percent and 10.20 percent. The Company's requested ROE of 10.20 percent is reasonable, if not conservative, and should be adopted.

Table 7: Summary of Analytical Results

Natural Gas Proxy Group			
	Low	**Mean**	**High**
DCF	8.77%	9.02%	9.37%
Mean CAPM	10.52%	10.72%	10.98%
Mean ROE (50/50 weighting)	9.65%	9.87%	10.18%
Combined Utility Proxy Group			
	Low	**Mean**	**High**
DCF	9.12%	9.30%	9.55%
Mean CAPM	10.38%	10.59%	10.85%
Mean ROE (50/50 weighting)	9.75%	9.94%	10.20%

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

ANN E. BULKLEY
VICE PRESIDENT

Ms. Bulkley has nearly two decades of management and economic consulting experience in the energy industry. Ms. Bulkley has extensive state and federal regulatory experience on both electric and natural gas issues including rate of return, cost of equity and capital structure issues. Ms. Bulkley has advised clients seeking to acquire utility assets, providing valuation services including an understanding of regulation, market expected returns, and the assessment of utility risk factors. Ms. Bulkley has assisted clients with valuations of public utility and industrial properties for ratemaking, purchase and sale considerations, ad valorem tax assessments, and accounting and financial purposes. In addition, Ms. Bulkley has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring and regulatory and litigation support.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Analysis and Ratemaking

Ms. Bulkley has provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking. Specific services have included: cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies; development of merchant function exit strategies; analysis and program development to address residual energy supply and/or provider of last resort obligations; stranded costs assessment and recovery; performance-based ratemaking analysis and design; and many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation).

Cost of Capital

Ms. Bulkley has provided expert testimony on the cost of capital testimony before several state regulatory commissions. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings over the past seven years. Ms. Bulkley's expert testimony experience includes:

- Northern States Power Company: Before the North Dakota Public Service Commission, provided expert testimony on the cost of capital for the company's North Dakota electric utility operations.
- WE Energies: Before the Michigan Public Service Commission, provided expert testimony in support of the company's cost of capital for its electric utility operations.
- Atmos Energy: Provided expert testimony in support of the company's return on equity and capital structure before the Public Utilities Commission for the State of Colorado.
- UNS Electric: Provided expert testimony in support of the company's return on equity and capital structure before the Arizona Corporation Commission.
- Portland Natural Gas Transmission: Provided testimony strategy as well as analytical support for cost of capital testimony before the Federal Energy Regulatory Commission.

- In addition to the specific cases listed above, Ms. Bulkley has provided testimony strategy as well as analytical support on cost of capital in several cases in the following states: Arizona, Colorado, Connecticut, Massachusetts, Minnesota, New Mexico, New York, North Carolina, South Carolina, South Dakota, Virginia, and Utah.

Valuation

Ms. Bulkley has provided valuation services to utility clients, unregulated generators and private equity clients for a variety of purposes including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Ms. Bulkley's appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal practice. In addition, Ms. Bulkley has relied on other simulation based valuation methodologies.

Representative projects/clients have included:

- Northern Indiana Fuel and Light: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Kokomo Gas: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost and comparable sales approaches.
- Confidential Utility Client: Prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract. .
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.

- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

Ratemaking

Ms. Bulkley has assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Analyzed and evaluated rate application. Attended hearings and conducted investigation of rate application for regulatory staff. Prepared, supported and defended recommendations for revenue requirements and rates for the company. Developed rates for gas utility for transportation program and ancillary services.

Strategic and Financial Advisory Services

Ms. Bulkley has assisted several clients across North America with analytically based strategic planning, due diligence and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed, and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Vice President
Assistant Vice President
Project Manager

Navigant Consulting, Inc. (1995 – 2002)
Project Manager

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EXPERT TESTIMONY OF ANN E. BULKLEY

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Tucson Electric Power	10/15	Tucson Electric Power	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Indiana Utility Regulatory Commission				
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Kokomo Gas And Fuel Company	09/10	Kokomo Gas And Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel And Light Company, Inc.	09/10	Northern Indiana Fuel And Light Company, Inc.	Cause No. 43943	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No.	Fair Value
Kansas Corporation Commission				
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Massachusetts Department of Public Utilities				
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets

New Mexico Public Regulation Commission				
Southwestern Public Service	06/15	Southwestern Public Service	C-15-001398-UT	Return on Equity
Southwestern Public Service	10/15	Southwestern Public Service	C-15-00296-UT	Return on Equity
New York State Department of Public Service				
New York State Electric and Gas Company	05/15	New York State Electric and Gas Company	Case No. 15-G-0284	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-	Return on Equity
North Dakota Public Service Commission				
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
South Dakota Public Utilities Commission				
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity

Before the Public Service Commission

National Fuel Gas Distribution Corporation

REBUTTAL TESTIMONY OF ANN E. BULKLEY

(VICE PRESIDENT OF CONCENTRIC ENERGY ADVISORS, INC.)

Dated: September 16, 2016

Testimony of Ann E. Bulkley

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A. My name is Ann E. Bulkley. I am a Vice President of Concentric Energy Advisors, Inc. ("Concentric"), located at 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. DID YOU ALSO SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I submitted Direct Testimony on behalf of National Fuel Gas Distribution Corporation ("Distribution" or the "Company"), the utility operating subsidiary of National Fuel Gas Company ("NFG") in Case 16-G-0257.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the Prepared Testimony of the Department of Public Service Staff ("Staff") Finance Panel witnesses regarding the appropriate return on equity ("ROE") and capital structure for the Company. My analysis is supported by the data presented in Exhibits__ (AEB-17) through (AEB-25).

II. SUMMARY AND OVERVIEW

Q. PLEASE SUMMARIZE FOR THE COMMISSION THE PRIMARY CONSIDERATIONS IN ESTABLISHING THE COST OF CAPITAL IN THIS PROCEEDING.

A. As established by the Supreme Court in the *Hope* and *Bluefield* decisions, the cost of capital that is set in this proceeding should be adequate to attract capital on reasonable terms and commensurate with the returns available to investors on risk-comparable investments. In *Hope*, the Supreme Court found that it is not the methodology employed, but the result reached that determines whether the ROE is just and reasonable. Therefore, while the Staff Panel and I employ several ROE estimation models in this process, it is important to consider whether the results of these analyses provide a reasonable return to investors. My testimony demonstrates that Staff has failed to consider this element of *Hope*.

Q. PLEASE SUMMARIZE THE RETURN RECOMMENDATIONS PROVIDED BY THE WITNESSES IN THIS PROCEEDING.

A. As shown in my Direct Testimony, I present the results of a Multi-Stage DCF analysis and two CAPM analyses, a traditional projected CAPM and a Zero-Beta CAPM, consistent with the methodology that has been relied on by the New York Public Service Commission ("Commission") since the Generic Finance Proceeding ("GFP"). My analysis was prepared using two proxy groups, a Combined Utility Proxy Group ("CUPG") and a Natural Gas Proxy Group ("NGPG"). In my Direct Testimony, I discussed the effect of capital market

conditions on the assumptions that are used to develop both of these ROE estimation methodologies. I also reviewed the foundation for the GFP and recommendations that resulted from that analysis of the appropriate ROE estimation models. Based on the effect that capital market conditions have had on the DCF model, I concluded that it was reasonable to consider an alternative weighting of the DCF and CAPM results, as was provided for in the Recommended Decision ("RD") in the GFP.[1] Based on an equal weighting of the results of those models, I established a range between 9.65 percent and 10.20 percent, and I supported the Company's request of a 10.20 percent ROE.

Based on the 1991 RD in the GFP and other Commission discussions of the ROE estimation methodology, the Staff Panel applies a two-thirds weighting to the results of the DCF analysis and a one-third weighting to the CAPM analysis. Staff's prescriptive approach fails to recognize that the Commission's methodology has evolved over time, and that the Commission is open to considering departures from past precedent, particularly when the influence of prevailing market conditions on ROE estimation analyses has led to distorted and unreasonable results.

The Staff Panel has acknowledged that current conditions in capital markets are causing the DCF model to understate the return requirements of equity investors.[2]

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[1] Direct Testimony of Ann E. Bulkley, at 71-76.
[2] Prepared Testimony of Staff Finance Panel, at 54-55.

Staff provides several options for the Commission to consider in terms of adjusting the DCF model results to account for current market conditions:[3]

1) change the measure of central tendency relied on from the median to the mean result of the models;

2) do not update the analysis from the March 2016 data, due to current market distortions;

3) adjust the averaging period to rely on a longer period of historical data; and

4) rely on the Federal Energy Regulatory Commission ("FERC") methodology for estimating the ROE.

In an effort to take into consideration the effect of low interest rates on the results of the DCF model, Staff ultimately chooses the first option (i.e., adjusting its methodology to rely on the mean DCF results rather than the median results).[4] While I agree with Staff that the DCF model is not producing reasonable results under current market conditions, I do not believe that Staff has adequately accounted for the magnitude of the understatement through its proposed adjustment. Stated simply, even though Staff readily admits that its DCF model is not producing reasonable results, it continues to rely on those results as the primary component of its ROE estimate.

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[3] *Id.*, at 94-97.
[4] *Id.*, at 55, 97.

Staff's 8.60 percent recommendation is based on current market data through June 2016, changing the measure of central tendency relied on to the mean result, and adjusting the ROE upward by 20 basis points based on Staff's recommended equity ratio of 42.3 percent, as compared with the average equity ratio authorized by the Commission of 48.0 percent.

Q. WHAT WAS STAFF'S POSITION IN THE GFP REGARDING THE REASONABLENESS OF THE TRADITIONAL DCF ANALYSIS?

A. In the GFP, Staff recognized that the volatility in the Commission's returns was related to reliance on the DCF model and that the DCF produced lower returns when stocks are selling above book value. As discussed in my direct and rebuttal testimony, currently utility stock valuations are high, which reduces the dividend yield and, as Staff noted in the GFP, results in low returns. Therefore, it is reasonable to weigh equally the results of the CAPM and the DCF so as not to bias the results downward due to the effect of market conditions on the DCF model.

> Staff, too, contends that the volatility of the Commission's returns over past periods justifies relying on a multi-method approach. Staff argues that reliance on traditional DCF analysis produces reasonable results over time, *but that at any specific time it could produce (and in the past has produced) inconsistent results*. Further, staff says that the DCF approach tends to produce returns higher than necessary when stocks are selling below book, and lower than necessary when stocks are selling above book. *In staff's view, DCF-based results are in no way superior to those*

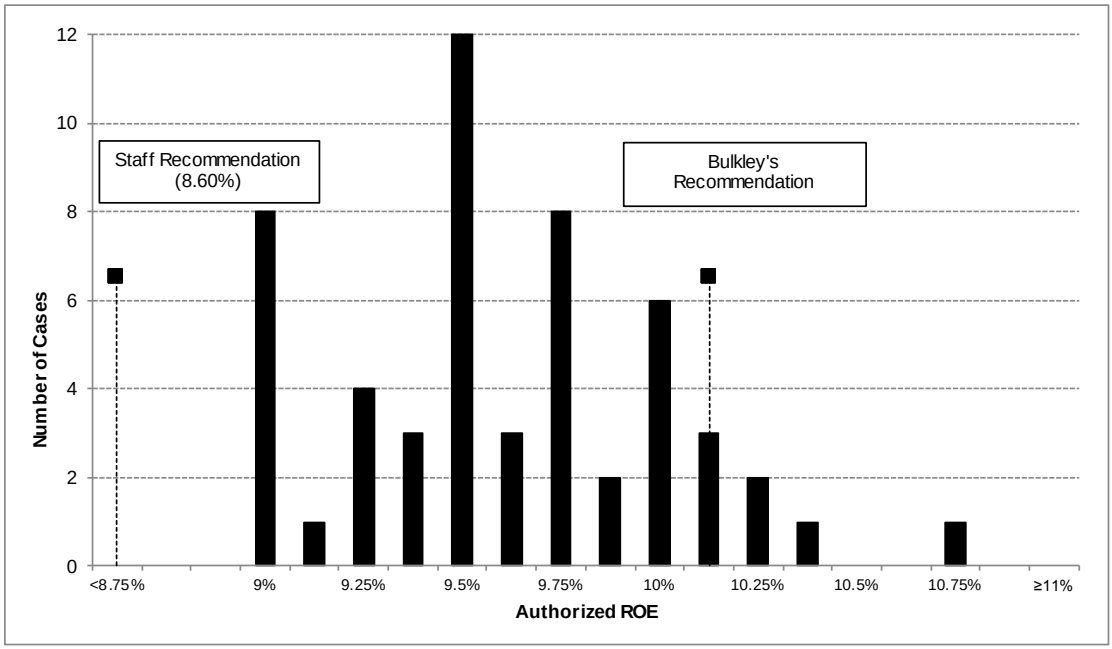
obtained using other methods, even though the DCF, on average, has been unbiased over time.[5]

Q. HOW DOES THE STAFF PANEL'S ROE RECOMMENDATION COMPARE TO RECENTLY AUTHORIZED ROEs FOR GAS DISTRIBUTION COMPANIES ACROSS THE NATION?

A. Chart 1 presents authorized ROEs for gas distribution companies from January 2014 through 2016. As shown in Chart 1, Staff's ROE recommendation of 8.60 percent is well below the lowest authorized ROE for a gas distributor during this time period.

[5] Case 91-M-0509, Proceeding on Motion of the Commission to Consider Financial and Regulatory Policies for New York State Utilities, Recommended Decision, (issued July 19, 1994) ("Generic Finance RD"), at 25. (Emphasis added.)

Chart 1: Authorized ROE for Natural Gas Distribution Companies
January 2014 through August 2016[6]



Q. HOW DOES STAFF'S PROPOSED EQUITY RATIO COMPARE TO THE EQUITY RATIOS OF THE PROXY COMPANIES?

A. As discussed in my Direct Testimony, the average actual equity ratio of the utility subsidiaries of the proxy companies over the last four years is approximately 54 percent for the CUPG and approximately 56 percent for the NGPG. As shown in Exhibit AEB-15 and AEB-16 to my Direct Testimony, the average authorized equity ratio of the utility subsidiaries of the proxy companies is 51.01 percent for the CUPG and 52.42 percent for the NGPG. Staff's proposed equity ratio of 42.3

[6] Source: Regulatory Research Associates.

percent is at least 870 basis points below the average authorized equity ratios of my proxy group companies.

Q. WHY SHOULD THE COMMISSION CONSIDER AUTHORIZED ROEs AND EQUITY RATIOS IN OTHER JURISDICTIONS AS A PRACTICAL BENCHMARK FOR ASSESSING COST OF CAPITAL RECOMMENDATIONS?

A. The combination of the ROE and equity ratio that is authorized in other jurisdictions provides a useful benchmark to assist the Commission in assessing the overall reasonableness of ROE estimates and sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, and financial growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher overall returns are available for other investments of comparable risk, investors have the incentive to direct their capital to those investments. Thus, an ROE and equity ratio that are significantly below authorized ROEs in other jurisdictions can inhibit the Company's ability to attract capital for investment in New York. This is also consistent with the approach taken in Opinion No. 531-B where the FERC departed from its long-standing position and determined that it was reasonable to consider state-level returns when estimating the cost of equity.[7]

[7] Federal Energy Regulatory Commission, Opinion No. 531-B, March 3, 2015, at paragraphs 80 and 84.

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR ANALYSIS AND ROE RECOMMENDATIONS AND THE ANALYSIS AND ROE RECOMMENDATIONS OFFERED BY THE STAFF PANEL IN THIS PROCEEDING?

A. While there are several technical differences in the specification of the DCF and CAPM models, all of which I will address in my Rebuttal Testimony, the most significant difference lies in how each party proposes to resolve what we both acknowledge is a major concern: how to adjust and interpret the results of ROE estimation models given current conditions in capital markets. As discussed in my Direct Testimony, the participants in the GFP recognized that the weightings that were relied on in 1991 could be revisited at some future point, and offered that the weightings were open for reconsideration for good cause.[8] As also discussed in my Direct Testimony, market conditions since the start of the Great Recession have demonstrated that there are compelling reasons to reconsider the weightings that resulted from the GFP.[9]

While I agree with the Staff Panel that the DCF model is not producing reasonable results under current market conditions, I do not believe that Staff has adequately accounted for the magnitude of the understatement through its proposal to adjust its ROE estimation methodology (i.e., relying on the mean rather than the median DCF results). Staff explains that recent market conditions

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[8] Direct Testimony of Ann E. Bulkley, at 9-10.
[9] *Id.*, at 73-76.

such as Britain's exit from the European Union as well as longer-term market conditions, such as the Federal Reserve's decision to "go slow" in raising interest rates have resulted in an increase in the price of utility stocks, as investors search for safe investments.[10] While Staff recognizes that these conditions have affected the ROE estimation models, their proposed adjustment does nothing to better reflect the projected market conditions during the period that the rates established in this case will be in effect because it continues to rely on the same weighting of the results from a DCF approach that Staff readily admits may be broken, and it does not account for investors' expectations of rising interest rates in the CAPM analysis.

Q. DO YOU AGREE WITH STAFF'S ALTERNATIVE PROPOSALS FOR ESTIMATING THE ROE?

A. No, because the Staff's proposals do not address the underlying issue. Current market conditions are similar to the market conditions that led to the GFP; utility stock valuations were high and the DCF model was underestimating the required return on equity. Rather than correcting for the anomalous conditions in the analysis, or minimizing the effect of these conditions on their recommended ROE, the Staff Panel's solution in this proceeding is simply to change the measure of central tendency (i.e., to move from relying on the midpoint result of the DCF analysis to the average DCF result). This change does not address the fact that the

[10] Prepared Testimony of Staff Finance Panel, at 54.

ROE results for each of the individual proxy companies to which the measure of central tendency is applied have been understated as a result of the significant decline in dividend yields for utility holding companies.

As noted previously, Staff offered the Commission three additional approaches for estimating the ROE:[11] 1) do not update the analysis from the March 2016 data, due to current market distortions; 2) adjust the averaging period to rely on a longer period of historical data, and 3) rely on the FERC methodology for estimating the ROE. The first two of these options rely on different historical time periods, both of which have been influenced by the market conditions that Staff has acknowledged have impacted the results of their models. The Federal Reserve's extraordinary intervention in capital markets, market volatility and uncertainty, and investors' flight to safety and search for yield have been ongoing through the Great Recession and the subsequent economic recovery. As shown later in Chart 2, throughout this period Treasury bond yields were suppressed and the price of utility stocks has increased, as shown by the S&P utilities index, resulting in declining dividend yields as investors sought higher yields through alternative dividend paying stocks, including utility stocks. As discussed in more detail in my Rebuttal Testimony, equity analysts have warned investors about high valuations and low dividend yields for utility stocks. With dividend yields artificially low, the DCF model has underestimated the prospective ROE for

[11] *Id*., at 94-96.

utility stocks for more than the six-month period that Staff proposes as an alternative to the 3-months of data that has been traditionally used by the Commission. Furthermore, since the ROE is intended to reflect the return that investors expect over some projected period, it is counterintuitive to rely on a longer historical time period. In fact, the Commission recently changed its policy on stock prices to rely on a shorter 3-month period instead of six months to avoid the use of "stale" data. This is especially important when the historical data differ significantly from investors' expectations, as is the case in the current market.

Finally, while I agree that the FERC methodology could be relied on, I note that simply changing the measure of central tendency without considering how the results of the DCF model have been affected is likely to continue to understate investors' return requirements.

Q. HOW DO YOU PROPOSE TO ADDRESS THE EFFECTS OF CURRENT MARKET CONDITIONS ON THE ROE ESTIMATION MODELS?

A. As discussed in my Direct Testimony, recognizing that market conditions are affecting the models used to estimate the cost of equity for public utilities, it is more appropriate to afford more weight to risk premium approaches, which allow for the ability to adjust for differences between current and projected market conditions. Moreover, it is critical for the Commission to recognize the limitations of the DCF model because the assumptions used in this model, in particular the dividend yield, cannot be reasonably adjusted to reflect projected market

conditions. Due to this limitation, it is reasonable to afford the DCF model less weight in the final recommended ROE. As discussed in my Direct Testimony, given the effect of market conditions on the ROE estimation models, it is reasonable and appropriate to apply equal weighting to the DCF and CAPM results.[12] As shown in Table 7 of my Direct Testimony, the results of that analysis suggest a range of returns from 9.94 percent to 10.20 percent.

Q. PLEASE SUMMARIZE YOUR POSITION ON STAFF'S PROPOSED REDUCTION IN THE COMMON EQUITY RATIO FOR DISTRIBUTION.

A. Staff's proposal to rely on NFG's current equity ratio of 42.3 percent represents a departure from Commission precedent and Staff's response to Distribution's proposals for the appropriate equity ratio in prior cases. Furthermore, Staff's proposal is well below the equity ratio established by the Commission for the other New York regulated utilities and well below the actual and authorized equity ratios of the utility subsidiaries of the proxy companies. Furthermore, Staff's incremental adjustment to the ROE to account for the proposed reduction in the equity ratio for Distribution does not adequately reflect the incremental risk from their proposal.

Addressing first the issues of precedent and consistency, the Commission has traditionally relied on a hypothetical capital structure of 48 percent equity as the appropriate ratemaking equity ratio for regulated utilities. In Distribution's last

[12] Direct Testimony of Ann E. Bulkley, at 75-76.

rate review in Case 13-G-0136, when NFG's equity ratio was 57.1 percent, (tr. 188), Staff, nevertheless, recommended that the Commission set Distribution's temporary rates based on a 48 percent equity ratio because it was comparable to the Commission's recent equity ratio authorizations for the compared companies.[13] Staff's recommendation in this case is inconsistent with their position in the last Distribution rate review. In the instant proceeding, Staff takes the position that it is appropriate to rely on NFG's current equity ratio, which is currently below the 48 percent equity ratio that the Commission has traditionally imputed. Considering Staff's positions in these two proceedings, it would appear that Staff's "methodology" with respect to the appropriate capital structure for the utility is to rely on the "lesser of" the Commission's 48 percent imputed equity ratio or the parent company capital structure. As discussed by the Company Finance Panel, NFG's equity ratio has been impacted dramatically by non-cash, and somewhat arbitrary, impairments in its oil and gas business.

Staff's proposal to increase the ROE by 20 basis points to adjust for their proposed reduction in the equity ratio is insufficient to reflect the incremental risk that a 42.3 percent equity ratio would inflict on Distribution. The increase in financial risk resulting from Staff's recommendation of an equity ratio that is 570 basis points below the average equity ratio of the other New York regulated utilities and at least 870 basis points below the average for the operating utilities

[13] National Fuel Gas Distribution Corporation, Case 13-G-1036, Tr. 196.

held by the proxy companies is not offset by Staff's proposed 20 basis points increase in the ROE. Finally, Staff's proposal that the implementation of ring-fencing provisions could decrease the risk of Distribution and warrant an increase in the equity ratio is not a reasonable solution. Furthermore, as discussed in the rebuttal testimony of Witness Reed and the Company Finance Panel, the Staff's ring-fencing provisions are unnecessary and without precedent in this rate proceeding, are likely to be viewed negatively by credit rating agencies and equity analysts, and would lead to significant costs to ratepayers.

Q. PLEASE SUMMARIZE THE TECHNICAL DIFFERENCES BETWEEN THE ROE ANALYSIS PRESENTED IN YOUR DIRECT TESTIMONY AND THE ANALYSIS PRESENTED BY THE STAFF PANEL.

A. Section IV of my Rebuttal Testimony addresses the technical differences between the analysis presented by Staff and my analysis and recommendations. Those differences include: 1) the weighting of the ROE estimation methodologies; 2) the composition of the proxy group; 3) the application of the DCF model, specifically the selection of growth rates; and 4) the application of the CAPM. In addition, Staff and I disagree as to the additional risk factors faced by the Company. As discussed in Section IV, reasonable modifications to Staff's proposed assumptions result in significant changes in the resulting ROE. Table 1 below summarizes the effects of these modifications.

Table 1: Summary of Adjustments to Staff's DCF and CAPM Analyses

Adjustment	ROE Result	Change from Staff Recommendation (in basis points)	Reference
Staff DCF result	**8.29%**		
Apply 375 basis point equity risk premium	9.71%	142	AEB-19
Use of GDP growth rate	8.67%	38	AEB-20
FERC estimate of the ROE result within DCF range	10.02%	173	
Staff CAPM result	**8.64%**		
Use of projected risk-free rate	9.21%	57	AEB-21
Use of S&P 500 to estimate the MRP	10.04%	140	AEB-22

III. CAPITAL MARKET CONDITIONS AND THEIR EFFECT ON THE COST OF EQUITY

Q. PLEASE SUMMARIZE THE STAFF PANEL'S VIEW OF CAPITAL MARKET CONDITIONS AND THEIR EFFECT ON THE COST OF EQUITY FOR DISTRIBUTION.

A. The Staff Panel notes that yields on 10-year Treasury bonds have declined by 45 basis points from January 2016 to June 2016.[14] Staff suggests that the currently low interest rate environment provides support for its ROE recommendation of 8.60 percent. In addition, Staff testifies that "current rates are the best indicator of future rates as they are based on the latest information available to investors."[15] For that reason, the Staff Panel rejects the use of projected Treasury bond yields in the CAPM and Risk Premium analyses. In doing so, Staff effectively takes an

[14] Prepared Testimony of Staff Finance Panel, at 91.
[15] *Id.*, at 91-92.

untenable position: that investors do not consider analysts' forecasts of inflation, interest rates, and earnings growth when assessing investments.

Q. HOW DOES YOUR VIEW OF CAPITAL MARKET CONDITIONS DIFFER FROM THE VIEW PRESENTED BY THE STAFF PANEL?

A. Since the ROE that is authorized in this proceeding is intended to provide a reasonable return to investors over the period during which rates will be in effect, it is important to consider the prospects for financial markets over that period. I disagree with Staff's recommendation that the Commission rely solely on current and recent historical market data for interest rates. In addition, it is important to understand how market conditions are affecting the results of the traditional ROE estimation models, and to use additional benchmarks to inform the decision on the appropriate ROE for Distribution in this case. The evidence demonstrates that interest rates are near historically low levels and that dividend yields for utility stocks have declined. It is important to understand not only how these market conditions developed, but also what changes in market conditions are expected in the future and how those changes affect a forward-looking estimate of the cost of capital. If analysts and investors are expecting higher interest rates, the Commission should consider the market's expectation for higher interest rates and how those higher interest rates would affect the assumptions of the DCF model.

Each model used to estimate the cost of equity has been developed using specific economic assumptions. Consequently, sound and reasonable judgment is required

in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the inputs for these models, and in interpreting the models' results. In other words, estimating the appropriate ROE is not just about mechanically applying the traditional ROE models and relying on the results generated. In order to meet the standards established in *Hope* and *Bluefield*, it is necessary to set the return at a level that is adequate to attract capital on reasonable terms. *Hope* instructs that it is not the methodology employed, but the result reached that determines whether an ROE is just and reasonable. Therefore, it is important to review the results of the ROE estimation models against other market indicators of the expected cost of equity to determine where, within the range of analytical results, the ROE is appropriately placed.

Q. PLEASE DISCUSS HOW THE FEDERAL RESERVE'S USE OF MONETARY POLICY HAS AFFECTED CAPITAL MARKETS.

A. The Federal Reserve's highly accommodative monetary policy has influenced capital markets by maintaining short-term interest rates at zero or, as of the December 2015 meeting, 25 basis points. Extraordinary and ongoing federal intervention in capital markets has artificially lowered government bond yields since the Great Recession of 2008-09, as the Federal Reserve has used monetary policy (both reductions in short-term interest rates and purchases of Treasury bonds and mortgage backed securities) to stimulate the U.S. economy. This highly accommodative monetary policy has resulted in government bond yields

that have been artificially suppressed by the Federal Reserve. The result of very low or zero returns on short-term government bonds has been that yield-seeking investors have been forced into longer-term instruments, bidding up prices and reducing yields on those investments. As investors have moved along the risk spectrum in search of higher yields that meet their return requirements, there has been an increase in the demand for dividend-paying equities, such as utility stocks. As a result, as shown later in Chart 3, there has been a decline in the dividend yields for utilities over the past decade. As Staff notes, recent uncertainty in the international financial markets has exacerbated this phenomenon.[16]

Q. DO YOU BELIEVE THAT CURRENT MARKET CONDITIONS ARE A "NEW NORMAL"?

A. No, the Federal Reserve has indicated on several occasions that it intends to withdraw its extraordinary support for financial markets and extricate itself from the market over time, by gradually selling the Treasury bonds and mortgage-backed securities that it purchased during the Quantitative Easing programs that followed the financial crisis. At the September 2014 Federal Open Market Committee ("FOMC") meeting, the FOMC published its "Policy Normalization Principles", which outlined the policy tools that would be implemented to return to normalcy. In a speech to the New York Economics Club, the Vice Chairman of the Board of Governors of the Federal Reserve, Stanley Fischer, again

[16] Prepared Testimony of Staff Finance Panel, at 54.

reiterated the Federal Reserve's Policy Normalization Principles, recognizing that interest rate increases would be in response to market conditions and the Federal Reserve's policy objectives.[17] As the Federal Reserve gradually unwinds the Quantitative Easing program by selling Treasury bonds and mortgage-backed securities into the market, the large supply of bonds will undoubtedly place upward pressure on interest rates.

Speaking at the Federal Reserve's annual conference in Jackson Hole, Wyoming on August 26, 2016, Federal Reserve Chair Janet Yellen indicated that the case for hiking interest rates has strengthened recently. Ms. Yellen stated: "In light of the continued solid performance of the labor market and our outlook for economic activity and inflation, I believe the case for an increase in the federal funds rate has strengthened in recent months."[18] In a speech on September 9, 2016, the President of the Boston Federal Reserve, Eric Rosengren, warned that waiting too long to raise interest rates threatened to overheat the U.S. economy. Furthermore, investors are commenting on the importance of normalizing monetary policy so that central banks do not cause instability in financial markets or encourage excessive risk-taking. Mohamed El-Erian, chief economist for Allianz, recently indicated that he thinks the Federal Reserve should not overlook the costs that come with their policy of maintaining historically low interest rates. In particular,

[17] Remarks by Stanley Fischer, Vice Chairman of the Board of Governors of the Federal Reserve at the Economics Club of New York, March 23, 2015.

[18] "Fed's Yellen says case for interest rate hike has strengthened," Reuters Business News, August 26, 2016.

he stated: "There is also the risk of financial instability down the road" because of extraordinary monetary policy. "And, I think that is the strongest argument for trying to slowly normalize rates, because otherwise you contribute to excessive risk taking. The last thing you want is for your central bank to be ineffective. The Fed doesn't want to get there, the ECB doesn't want to get there, the bank of England doesn't want to get there. And they (the ECB) have that at the back of their mind."[19]

Q. WHAT IS THE FINANCIAL MARKET'S PERSPECTIVE ON THE TIMING OF FUTURE INCREASES IN INTEREST RATES?

A. The September 2016 issue of the Blue Chip Financial Forecasts ("Blue Chip") surveyed 50 leading economists and market participants concerning their views regarding the timing of future increases in short-term interest rates by the Federal Reserve. Blue Chip reports that approximately 79 percent of market participants surveyed expect the Federal Reserve to raise short-term interest rates again before the end of 2016.[20] In terms of magnitude, 76 percent of those surveyed expected the Federal Reserve will raise the Federal Funds rate by 25 basis points in 2016, and 85 percent expect an additional increase in 2017 of between 50 and 100 basis points.[21]

According to Blue Chip, yields on 30-year Treasury bonds are forecasted to

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[19] "El-Erian: Low Rate Lead to Excessive Risk-Taking," Investopedia, August 26, 2016.
[20] Blue Chip Financial Forecasts, Volume 35, No. 9, September 1, 2016, at 14.
[21] *Id*.

increase from the current level of 2.40 percent to 4.30 percent between 2018 and 2022.[22] If yields on Treasury bonds rise as the market expects, the current dividend yields for electric and gas utility stocks will not be competitive with higher yields on government and corporate bonds. Consequently, the results of Staff's DCF analysis are understated because the current dividend yield component does not adequately reflect the higher interest rate environment that is expected by investors.

Q. WHAT INDICATIONS ARE THERE THAT INVESTOR RISK SENTIMENT IS INCREASING?

A. As discussed in my Direct Testimony, the evidence of increased risk sentiment among investors is compelling.[23] Even as Treasury bond yields have declined again in 2016, the spread between yields on corporate and utility bonds and government bonds has increased to levels not seen since the 2008-09 credit and financial crisis. As shown in my Direct Testimony, the spread between Baa-rated utility debt and 30-year Treasury bonds was 260 basis points, or 115 basis points higher than the spread just prior to the Great Recession.

As discussed in my Direct Testimony, higher credit spreads are an indication that bond investors are becoming more concerned about future economic conditions and the ability of corporations to withstand any economic downturn that may

[22] Blue Chip Financial Forecasts, Volume 35, No. 6, June 1, 2016, at 14.
[23] Direct Testimony of Ann E. Bulkley, at 18-22.

occur.[24]

Q. ARE EXPECTATIONS FOR HIGHER INTEREST RATES, WIDER CREDIT SPREADS, LOWER DIVIDEND YIELDS, AND HIGH STOCK VALUATIONS FOR UTILITY COMPANIES ALREADY REFLECTED IN THE COST OF EQUITY PRODUCED BY THE DCF MODEL?

A. In theory, and during times of general economic and capital market stability, I believe that the DCF model reflects market conditions and investor expectations. However, in the current market environment, the DCF model results are being distorted by the uncommonly low level of interest rates and the corresponding effect on dividend yields. The Staff Panel comments on this trend, noting "that investors have fled to less risky investments including utility stocks, which pushed the S&P 500 Utilities Index to a record high of 258.15 in the month of June."[25] Value Line recently observed that dividend yields for electric utilities are currently well below the historical average, that many of these stocks trade at a premium to the market, which is unusual for utilities, and that high valuations on utility shares are not expected to be sustained over the three-to-five year period.[26] In order to assess how low interest rates are affecting the dividend yields for utility stocks, I compared the S&P utilities index to the yield on the 30-year Treasury bond since 2007. As shown in Chart 2, the S&P utilities index has

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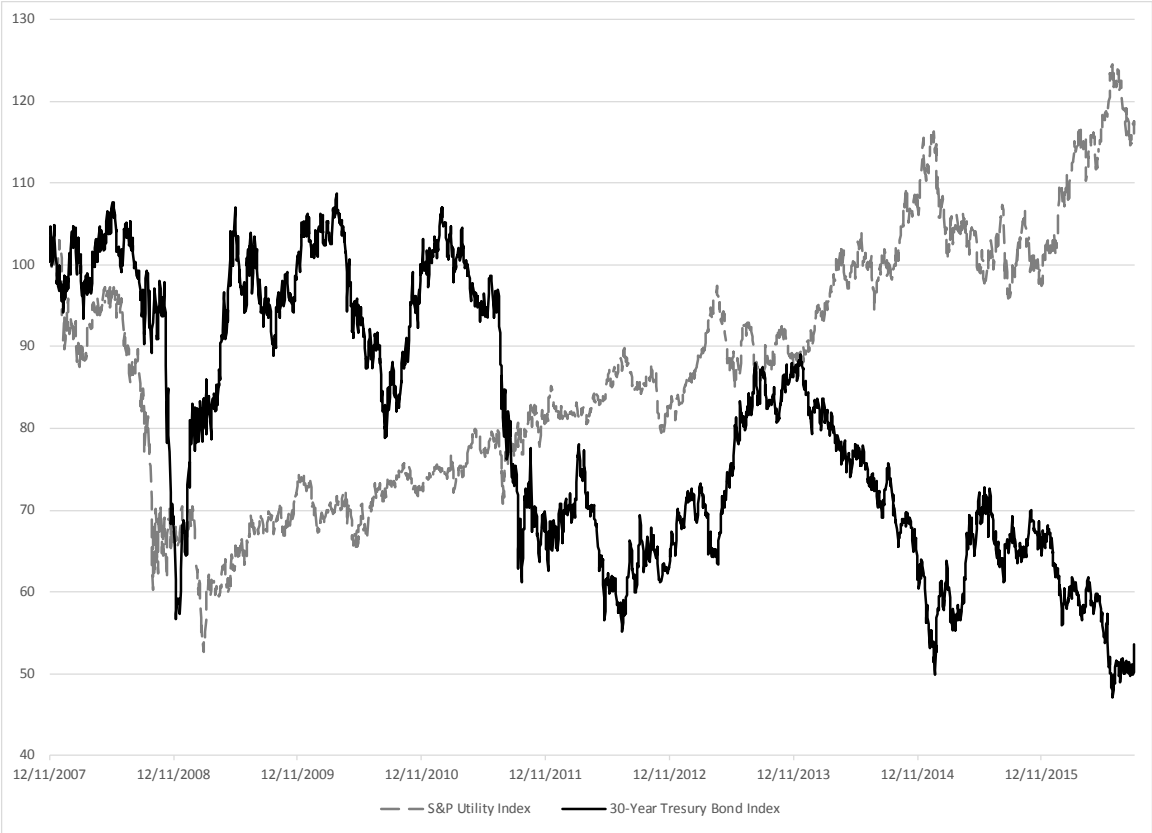
24 *Id.*, at 21-22.
25 Prepared Testimony of Staff Finance Panel, at 54-55.
26 Value Line Investment Survey, Electric Utility (East) Industry, August 19, 2016, at 140.

increased steadily as yields on 30-year Treasury bonds have declined in response to federal monetary policy.

Chart 2: S&P Utilities Index and U.S. Treasury Bond Yields 2007 – 2016



Q. HAS ANY OTHER REGULATORY COMMISSION RECOGNIZED THE EFFECT OF ANOMALOUS CAPITAL MARKET CONDITIONS ON THE DCF MODEL?

A. Yes. As discussed in my Direct Testimony, the FERC has recognized that anomalous conditions in capital markets have affected the results of the DCF model. In another more recent decision, the FERC found that 10-year Treasury

bond yields are evidence of anomalous conditions in capital markets, and that the low interest rate environment is reducing the dividend yield component of the DCF model, stating:

> As is discussed, *infra*, the level of the dividend yield affects the reliability of the DCF process when that level is lower than the level acceptable to investors that value utility stocks based on their estimated long-term dividend growth. The record creates cause for concern that during a period including the Study Period, investors valuing utility stocks based solely or primarily on their current yield bid the prices of the proxy group stocks up to levels that rendered their Total Returns unacceptable to investors that valued such stocks based on their estimated long-term dividend growth. For reasons set out below, this record evidence creates further cause for concern that placement of the MISO TOs' Base ROE at the Midpoint may not meet the requirements of *Hope*.[27]

The FERC also observed that due to anomalous conditions in capital markets (i.e., low Treasury bond yields) the midpoint results of the DCF model are not a reasonable estimate of the cost of equity at this time, stating:

> The yields of 10-year Treasury Bonds during the Study Period continue to reflect economic conditions that could render inputs to the DCF analysis unrepresentative. During the study period, the yields of 10-year Treasury Bonds averaged 2.21 percent. That yield was 38 basis points higher than the average yield of those bonds during the Opinion No. 531 study period, but 79 basis points below the 3.0 percent level that so concerned the Commission in Opinion No. 531. If the average 10-year Treasury-Bond yields for the Opinion No. 531 study period reflected economic conditions that could serve to

[27] 155 FERC ¶ 63,030 (June 30, 2016) at para. 128.

> render financial inputs into the DCF model unrepresentative, the average bond yields for the study period in this proceeding are close enough to the earlier yields to reflect the same conditions. Accordingly, the level of 10-year Treasury Bond yields during the Study Period create sufficient doubt regarding the representativeness of DCF inputs to warrant an examination of alternative metrics prior to making a final determination as to the level of the MISO TOs' Base ROE.[28]

Consequently, the FERC has determined that it is necessary to consider the results of other Risk Premium models (such as a forward-looking CAPM analysis and a Bond Yield Plus Risk Premium methodology) and returns in other jurisdictions in order to assess the reasonableness of the DCF results and to determine where to set the appropriate return on equity within the range of results.

Q. WHAT IS YOUR CONCLUSION REGARDING THE EFFECT OF CAPITAL MARKET CONDITIONS ON THE AUTHORIZED ROE FOR DISTRIBUTION?

A. My primary conclusion is that, under current market conditions, the DCF model reflects low dividend yields and high valuations on utility shares which are not considered sustainable in light of investors' expectations for higher interest rates. As demonstrated by the Blue Chip forecasts, investors expect interest rates to increase as the Federal Reserve withdraws the extraordinary level of monetary stimulus that has been provided to the U.S. economy since the Great Recession. As interest rates rise, dividend yields on utility shares become less competitive with higher yields on government and corporate bonds. As discussed above, the

[28] *Id*., at para. 126.

FERC was concerned that DCF results reflected anomalous market conditions when yields on 10-year Treasury bonds were at 3.0 percent. Those same yields are now approximately 1.55 percent in August 2016. As a result, it is necessary to place more emphasis on the results of alternative risk premium based models and returns in other jurisdictions in order to determine where the ROE should be set within a reasonable range of results from the DCF model.

IV. RESPONSE TO STAFF FINANCE PANEL

Q. WHAT IS STAFF'S ROE RECOMMENDATION IN THIS PROCEEDING?

A. Staff derives an ROE estimate of 8.4 percent, based on a two-thirds weighting of the DCF model results of 8.29 percent and a one-third weighting of the average CAPM results of 8.64 percent.[29] Staff then adds 20 basis points to this ROE estimate in recognition that they are proposing to reduce the equity ratio for Distribution to 42.3 percent, as compared to the average for the proxy group companies of approximately 48.0 percent.[30]

Q. WHAT ARE THE PRIMARY AREAS OF DISAGREEMENT BETWEEN STAFF AND YOU AS IT RELATES TO THE AUTHORIZED COST OF CAPITAL FOR DISTRIBUTION?

A. The Staff Panel's methodology and analysis, as well as its criticism of my ROE estimation methodologies are based on the principle of consistency with prior Commission methodologies rather than specific criticisms of my methodology.

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29 Prepared Testimony of Staff Finance Panel, at 67.
30 *Id.*, at 70-71.

Staff refers multiple times to Commission precedent as the basis for key assumptions in its ROE estimation methodology. The foundation of Staff's criticisms of my methodology is simply that the Commission has not developed the ROE estimation models using the data and methods that I relied on. Staff does not provide any evidence to demonstrate that my assumptions and methods are not those used by investors or are not reasonable. Simply, Staff's position is that my approach is not what was used in the past. While Staff cites to many instances where they have followed "precedent" with respect to the development of assumptions, they fail to acknowledge that there are several instances where the Commission has changed its approach to be responsive to market conditions.[31] This forms the basis of the disagreement between my ROE estimation approach and Staff's methodology.

The specific areas of disagreement are as follows: (1) the weighting of the DCF and CAPM results; (2) the composition of the proxy group and the screening criteria used to develop a risk comparable group; (3) the application of the DCF model and the reasonableness of the results produced by the DCF model under current market conditions; (4) the application of the CAPM and the reasonableness of making adjustments to the inputs and assumptions used in that model given the current low interest rate environment; (5) the business risks faced

[31] Staff's strict adherence to precedent with respect to the weighting of the ROE estimation models is also internally inconsistent with its movement to the mean result of the DCF model and the decision to rely on the parent company equity ratio, when the Commission precedent has been a 48 percent equity ratio.

by Distribution relative to the proxy group; and (6) the appropriate capital structure to be used for ratemaking purposes by Distribution. The following sections address each of these areas of disagreement.

1. WEIGHTING OF DCF AND CAPM METHODOLOGIES

Q. WHY DID THE COMMISSION INITIATE THE GFP?

A. As discussed in my Direct Testimony, the GFP was initiated because the Commission recognized that the DCF method was particularly sensitive to interest rate fluctuations and was producing returns far below the returns produced by other methodologies.[32] Contrary to the consensus recommendation of the parties to the GFP for an equal weighting of the DCF and CAPM methodologies[33,] the RD proposed that a two-third/one-third weighting be applied to the results of the DCF and CAPM analyses, respectively, with less weight given to CAPM methodology because it had only been used to that point as a check on the DCF model.[34]

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[32] Case 91-M-0509, Proceeding on Motion of the Commission to Consider Financial and Regulatory Policies for New York State Utilities, Recommended Decision, (issued July 19, 1994) ("Generic Finance RD"), at 2.

[33] *Id*., at 26.

[34] *Id*., at 27.

Q. WHAT JUSTIFICATION DOES STAFF PROVIDE FOR ITS DECISION TO CONTINUE PLACING TWO-THIRDS WEIGHT ON THE DCF MODEL RESULTS?

A. Staff relies on the GFP and subsequent cases to support the weighting of DCF and CAPM results.[35] Staff also asserts that the DCF model is superior to the CAPM because the DCF model has one input of primary controversy (i.e., the growth rate), while the Beta and market risk premium components of the CAPM are "less observable and more dependent on estimations."[36] Staff also asserts that, "The DCF application of fewer subjective inputs relative to the CAPM provides a more stable foundation, thus a lesser chance of error in a ROE calculation".[37] While Staff relies on the GFP to support its decision to place two-thirds weight on the DCF results, Staff fails to acknowledge that the RD in the GFP left open the possibility that the weightings and methodologies could be adjusted if necessary to ensure that the results promote regulatory credibility. During the GFP, Staff's position was that "reliance on traditional DCF analysis produces reasonable results over time, *but that at any specific time it could produce (and in the past has produced) inconsistent results*."[38] Furthermore, Staff indicated that "*DCF-*

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35 Prepared Testimony of Staff Finance Panel, at 67-69 and 77-78.
36 *Id*., at 68.
37 *Id*., at 68-69.
38 Case 91-M-0509, Proceeding on Motion of the Commission to Consider Financial and Regulatory Policies for New York State Utilities, Recommended Decision, (issued July 19, 1994) ("Generic Finance RD"), at 25. (Emphasis added.)

based results are in no way superior to those obtained using other methods, even though the DCF, on average, has been unbiased over time."[39]

Q. DOES STAFF PROVIDE EXAMPLES OF THE COMMISSION'S THOUGHTS REGARDING THE WEIGHTING OF THE DCF AND CAPM RESULTS?

A. Yes. Staff testifies that since 1994, the Commission has consistently preferred cost of equity determinations with 2/3 DCF and 1/3 CAPM weightings.[40] In particular, Staff cites Case 13-E-0030 and Case 10-E-0362 as recent support for the Commission's view on the appropriate weighting of DCF and CAPM results. While I have reviewed each of those decisions, it is important to recognize that the original decision not to afford equal weight to the results of the CAPM was based simply on a lack of experience with the model. That determination was made more than 20 years ago.

Q. WHAT DO YOU CONCLUDE FROM THE COMMISSION DECISIONS REFERENCED BY STAFF?

A. Based on my review of the decision approving the joint proposal for Consolidated Edison in Case 13-E-0030, I find no evidence that the Commission either considered alternative weighting structures, or specifically determined that the two-thirds weighting on the DCF results was superior to an alternative weighting proposal. With respect to Case 10-E-0362, this decision does support the 2/3

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39 *Id.*

40 Prepared Testimony of Staff Finance Panel, at 77.

DCF and 1/3 CAPM weighting. However, the order shows a willingness to consider future changes to that weighting when it states: "We agree with the RD that no convincing demonstration has been made in this case that something about this particular utility or these particular economic times is sufficiently unique to require us to modify any of these basic aspects of our model."[41]

Q. STAFF ALSO CITES THE DISCUSSION OF THE WEIGHTING OF THE DCF AND CAPM RESULTS FROM CASE 06-E-1433. WHAT ARE THE IMPORTANT FACTORS TO CONSIDER IN REVIEWING THE COMMISSION'S DECISION IN THAT CASE?

A. First, it is important to note that the Commission's decision was issued in October 2007, before the financial crisis of 2007-2009 and the ensuing Great Recession, as well as the Federal Reserve's extended involvement in the financial markets that began following those events and continues today. Therefore, the market data used in Case 06-E-1433 to estimate the projected ROE were not influenced by anomalous market conditions such as have been experienced in recent history and that affect the market data used in the ROE estimation methodologies in these proceedings.

Second, the Commission notes that it changed its calculation of the market return used in the estimation of the market risk premium in the CAPM. The Commission recognized that the use of historical returns published by Ibbotson were stale and less reliable and therefore began relying on projected returns as

[41] State of New York Public Service Commission, Case 10-E-0362, at 64.

published by Merrill Lynch. In this same case, the Commission recognized that six-month average stock prices could be "stale."[42] Currently, the Commission's methodology relies on three-month average stock prices. These types of changes demonstrate that the Commission is willing to consider modifications to the ROE estimation methodology to include more current and relevant information as market conditions change.

Finally, it is important to note that the Commission decision in Case 06-E-1433 did not state that it would never consider changing the weights on the ROE estimation methodologies. Rather, the Commission's conclusion at that time, nearly ten years ago, was that it was "not ***now*** inclined to deviate from our long-held view that the CAPM should not be entitled to more than one-third of the weight."[43] The Commission explicitly left open the possibility that there would be a point in the future when it would be appropriate to consider such a change. Based on the data I have presented and the viewpoints provided by other regulatory commissions, it is reasonable to conclude that current market conditions now warrant such a change.

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[42] State of New York Public Service Commission, Case 06-E-1433, at 11.
[43] *Id*., at 15. (Emphasis added.)

Q. WHY DO YOU BELIEVE THAT CURRENT CONDITIONS IN CAPITAL MARKETS SUPPORT RECONSIDERATION OF THE WEIGHT PLACED ON THE DCF AND CAPM METHODOLOGIES?

A. When the RD was issued in the GFP in 1991, one of the primary concerns identified by the Commission was that the low interest rate environment was causing the DCF model to understate investors' return requirements.[44] The Commission also noted that there was nothing sacrosanct about the DCF return on equity analysis.[45] The average daily yield on 30-year Treasury bonds in 1991 was 8.14 percent, whereas the average daily yield on 30-year Treasuries in 2016 through August has been 2.54 percent. The extraordinarily low interest rate environment today should do nothing to alleviate the Commission's concerns about how the DCF model is affected by the low interest rate environment. On the contrary, if the interest rate environment in 1991 was sufficient reason for the RD in the GFP to conclude that placing one-third weight on the CAPM results was appropriate, then the current interest rate environment should provide sufficient basis for a conclusion that the weighting of the DCF and CAPM methodologies should be modified in this case.

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[44] 1994 N.Y. PUC Lexis 141, *37.
[45] *Id.*

Q. HAS STAFF PROVIDED ANY ANALYSIS EXPLAINING WHY THIS EXTRAORDINARY CHANGE IN INTEREST RATE CONDITIONS DOES NOT SUPPORT A CHANGE IN THE DCF WEIGHTING?

A. Staff provided no record evidence addressing this topic.

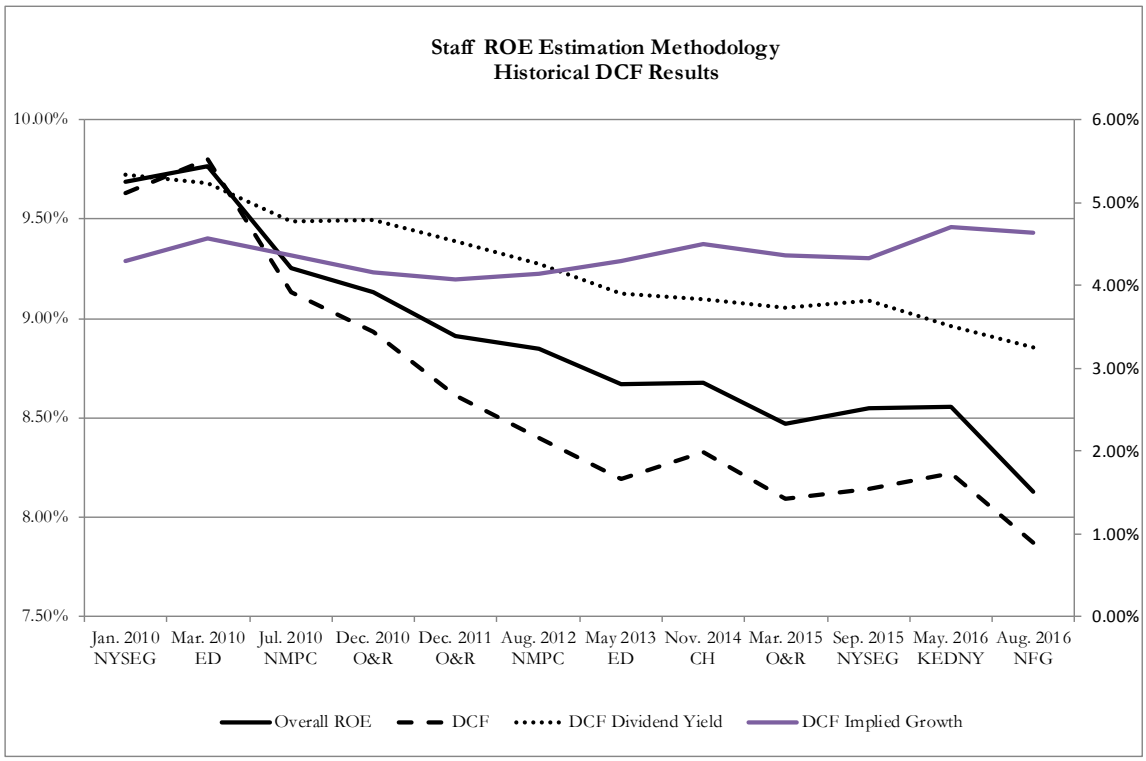
Q. HAVE YOU CONDUCTED ANY ANALYSIS REGARDING HOW THE RESULTS OF STAFF'S DCF AND CAPM ANALYSES ARE BEING AFFECTED BY CAPITAL MARKET CONDITIONS?

A. Yes, I first looked at the results produced by Staff's DCF and CAPM analyses. I then compared those results to the DCF and CAPM results that are produced by reflecting investor expectations of future market conditions.

Q. WHAT RESULTS HAVE STAFF'S DCF AND CAPM APPROACHES PRODUCED OVER RECENT YEARS?

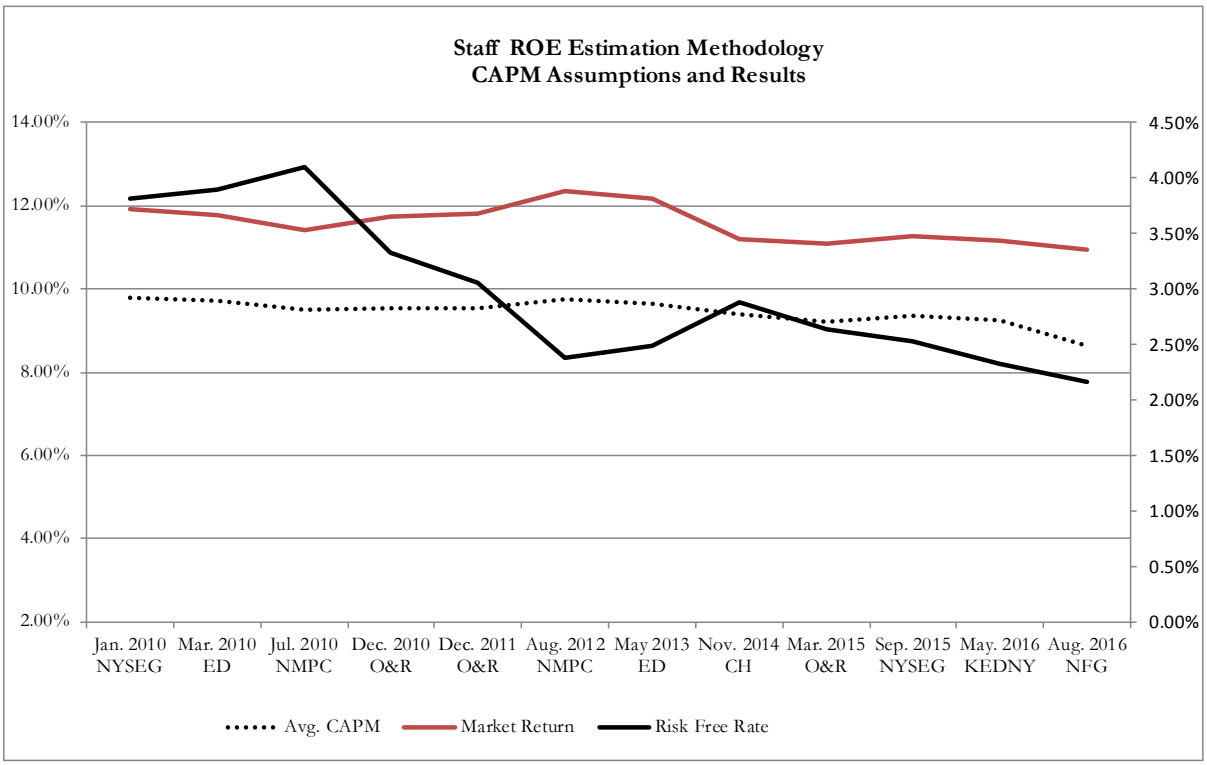
A. I have prepared two charts showing Staff's DCF and CAPM estimates over the period from 2010-2016. As shown in Chart 3, the growth rates in the DCF analysis have increased slightly over this period, while the dividend yields have declined in response to capital market conditions and lower Treasury bond yields. In summary, the lower DCF results are attributable almost entirely to lower dividend yields, which are a function of low government bond yields.

Chart 3: Staff DCF Estimate for NY utilities 2010-2016



As shown in Chart 4, the market return used to estimate the market risk premium in the CAPM method has fallen slightly over this time period, while the risk-free rate has declined significantly. As with the DCF results, the lower CAPM results are primarily attributable to the drop in Treasury bond yields.

Chart 4: Staff CAPM Estimate for NY utilities 2010-2016



Q. CAN THE DCF AND CAPM MODELS BE ADJUSTED TO REFLECT PROJECTED MARKET CONDITIONS?

A. It is possible to reflect projected market conditions in the CAPM by also considering projected Treasury bond yields. The analysis shown in Chart 4 above does not rely on projected Treasury bond yields; however, the results of the CAPM presented in my Direct Testimony, and Exhibit AEB- 7 do provide CAPM results based on short and longer-term interest rate projections. The average of the CAPM results presented in that exhibit is 10.59 percent, and the increase in the ROE based on the use of projected data is as high as 67 basis points.

There is not, however, a comparable method to correct the DCF analysis to account for current historically low dividend yields that are unstainable in light of forecasts of higher interest rates are considered. This supports my position that less weight should be afforded the DCF results at this time.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE WEIGHTING OF THE DCF AND CAPM METHODOLOGIES?

A. As discussed previously, the GFP was initiated because the Commission recognized that the DCF methodology was particularly sensitive to interest rate fluctuations and was producing returns far below the returns produced by other methodologies. Based on the data presented in Chart 3, I conclude that in current market conditions, the DCF model suffers from the same infirmities. Therefore, I conclude that it would be appropriate to equally weight the results of the DCF and CAPM models.

The Company's proposed ROE of 10.20 percent, which relies on an equal weighting of the results of the DCF and CAPM methodologies, is appropriate and reasonable under the current circumstances. While I understand the desire to employ a consistent process to estimate the return on equity, the *Hope* decision is not consistent with this concept; "[u]nder the statutory standard of 'just and reasonable,' it is the result reached, not the method employed, which is controlling." Staff's ROE recommendation of 8.60 percent, which is based on a purely mechanical weighting of the DCF and CAPM results that was established

25 years ago, does not even attempt to provide an assessment of the "just and reasonable" standard and is not comparable to returns available to investors in other jurisdictions for companies with comparable risk.

As shown in Exhibit __ (FP-15), Staff's application of the DCF model results in a mean ROE for the proxy group of 8.29 percent, which is:

1) 71basis points below the lowest authorized ROE for a gas distribution company (i.e., 9.00 percent) since January 2014;

2) 136 basis points below the mean return for a gas distribution company (i.e., 9.65 percent) over that period; and

3) 68 basis points below its Zero-Beta CAPM results of 8.97 percent.

In summary, the DCF model is not producing reasonable results as compared to the results of other risk-premium based models, such as the CAPM, and is not producing returns that are consistent with those authorized in other jurisdictions. This provides the Commission with the "good reason" contemplated in the RD of the GFP to consider placing more weight on the results of alternative ROE estimation methodologies.

2. PROXY GROUP COMPOSITION

Q. WHAT IS YOUR POSITION WITH RESPECT TO THE PROXY GROUP COMPOSITION?

A. The proxy group appropriately consists of companies that are comparable in business and financial risk to Distribution. The importance of selecting a proxy group that is similar in overall financial and business risk to the subject company

was endorsed by the United States Court of Appeals for the District of Columbia (the "Circuit Court") in the *Petal Gas Storage* decision. The Circuit Court indicated that the goal of a proxy group is to rely on companies that possess similar risk to the subject company for the determination of the cost of equity:

> That proxy group arrangements must be risk-appropriate is the common theme in each argument. The principle is well-established. *See Hope Natural Gas Co.*, 320 U.S. at 603 ("[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."); *CAPP I*, 254 F.3d at 293 ("[A] utility must offer a risk-adjusted expected rate of return sufficient to attract investors."). The principle captures what proxy groups do, namely, provide market-determined stock and dividend figures from public companies comparable to a target company for which those figures are unavailable. *CAPP I*, 254 F.3d at 293–94. Market determined stock figures reflect a company's risk level and, when combined with dividend values, permit calculation of the "risk-adjusted expected rate of return sufficient to attract investors."
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> ***
>
> What matters is that the overall proxy group arrangement makes sense in terms of relative risk and, even more importantly, in terms of the statutory command to set "just and reasonable" rates, 15 U.S.C. § 717c, that are "commensurate with returns on investments in other enterprises having corresponding risks" and "sufficient to assure confidence in the financial integrity of the enterprise . . . [and] maintain its credit and . . . attract capital," Hope Natural Gas Co., 320 U.S. at 603.[46]

Consistent with the Circuit Court's decision, I have selected a proxy group of companies with comparable investment risk to Distribution. In contrast, Staff

[46] *Petal Gas Storage v. FERC*, 496 F.3d 695, 699 (D.C. Cir. 2007).

applied less stringent screening criteria, resulting in a larger, less comparable proxy group.

Q. DO YOU AGREE WITH THE STAFF PANEL THAT YOUR PROXY GROUP IS LESS COMPARABLE TO DISTRIBUTION THAN STAFF'S PROXY GROUP CONSISTING OF FOUR GAS DISTRIBUTION COMPANIES AND 26 ELECTRIC UTILITIES?

A. No, I do not. While my proxy group also includes both gas distribution companies and electric utilities, the business and operating risks for gas distributors and electric utilities are different. In my view, investors would give more weight to market data for companies in the gas distribution industry and less weight to electric utilities. Electric utilities account for approximately 87 percent of Staff's ROE estimate, while gas distribution companies account for the remaining 13 percent. In addition, as shown in Exhibits___(AEB-17) and (AEB-18), the average S&P credit ratings for the companies in my proxy group is A-, which is one notch higher than the average credit rating of Staff's proxy group of BBB+ (as shown in Exhibit___(FP-14). Credit ratings are an important measure of investment risk that consider both the business and financial risk of the company being rated. On that basis, I conclude that my proxy group has lower investment risk than Staff's proxy group.

Q. HOW DO THE AUTHORIZED ROEs FOR YOUR PROXY GROUP COMPARE WITH STAFF'S PROPOSED ROE?

A. The average authorized ROE of my Combined Utility Proxy Group ("CUPG") is 9.94 percent, which is 134 basis points higher than Staff's proposed ROE. The range of authorized ROEs for the A- rated proxy companies is 9.21 percent to 10.32 percent, with a mean of 9.90 percent. This range is 61 to 172 basis points above Staff's proposed ROE.[47]

Q. DO YOU AGREE THAT STAFF'S SCREEN BASED ON PERCENTAGE OF REGULATED REVENUE RESULTS IN A MORE COMPARABLE PROXY GROUP THAN YOUR SCREEN BASED ON PERCENTAGE OF OPERATING INCOME?

A. No, I do not. Staff asserts that my "application of operating income (earnings) instead of regulated revenue for establishing the proxy group may allow companies into the group that contain substantially greater risk than a typical regulated utility."[48] In addition, Staff also asserts that, "[u]sing 70% of operating income criteria could introduce companies into the proxy group that have a higher inherent risk profile than is proper for a regulated utility proxy group."[49]

As explained in my Direct Testimony, I relied on the percentage of net operating income derived from regulated operations instead of the percentage of total revenue derived from regulated operations because net operating income is more

[47] The average credit rating of the NGPG is also A-, and the average ROE of this group is 9.86 percent.
[48] Prepared Testimony of Staff Finance Panel, at 74.
[49] *Id.*

representative of the contribution of that business segment to earnings and cash flow (the measures that matters most to investors), as well as the corporation's overall financial position.[50] Furthermore, relying on a revenue screen does not provide a clear or necessarily consistent indicator of the contribution of regulated utility operations to a company's earnings because revenue includes the underlying cost of gas, which is fully passed through to customers. Since fuel costs are the single largest cost, the price of fuel can dramatically influence the overall revenue of a company without having an effect on the profitability of the business segment.

Q. STAFF CONTENDS THAT BOTH OF YOUR PROXY GROUPS HAVE SIGNIFICANTLY HIGHER BUSINESS RISK THAN THOSE OF STAFF'S PROXY GROUP.[51] WHAT IS YOUR RESPONSE?

A. Staff's Exhibit___(FP-14) provides the S&P business risk profiles for the companies in Staff's proxy group; the median S&P business risk rank for Staff's proxy group is "Excellent". As shown in Exhibit AEB-9 to my Direct Testimony, I compared the S&P business risk ranking for my CUPG to the Company's business risk ranking. As shown in that exhibit the average and median business risk profiles from S&P for the 19 companies in my CUPG are "Excellent" /

[50] Direct Testimony of Ann E. Bulkley, at 28-29.
[51] Prepared Testimony of Staff Finance Panel, at 75.

"Intermediate". On that basis, I conclude that the companies in my CUPG have comparable business risk as the companies in the Staff Panel's proxy group.

3. APPLICATION OF THE DCF MODEL

Q. PLEASE SUMMARIZE THE STAFF PANEL'S APPLICATION OF THE DCF MODEL.

A. Staff uses a two-stage DCF model that forecasts dividends from 2016 to 2020 using Value Line's estimates of projected dividends in that period, and a "sustainable growth rate" from 2021 forward. Using the DCF methodology, Staff calculates a median ROE for its proxy group of 7.87 percent and a mean ROE of 8.29 percent.[52] Staff notes that "[t]here have been several significant disruptions in the market recently that we believe have affected Staff's ROE model results."[53] On that basis, Staff has adjusted its methodology to rely on the mean DCF results rather than the median DCF results because "very recently it appears to us that using the median is suppressing the ROE below what the 'average' or 'typical' investor in the proxy group would require at this time."[54] Staff continues to apply a 2/3 weight to the DCF model results in deriving its overall ROE recommendation.

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52 *Id.*, at 53.
53 *Id.*, at 54.
54 *Id.*, at 55.

Q. BEFORE DISCUSSING YOUR POINTS OF DISAGREEMENT WITH STAFF'S DCF METHODOLOGY, DO YOU HAVE ANY PRELIMINARY COMMENTS ON THE REASONABLENESS OF STAFF'S DCF RESULTS?

A. Yes, Staff acknowledges that the dividend yields for their proxy group are low based on anomalous market conditions. This is the driver for the low DCF results. Changing the measure of central tendency from relying on the midpoint to the average of a range of results that Staff recognizes is artificially low as a result of market conditions does not address the concern that the DCF model is not producing reliable results. The unrealistically low median result of the DCF model should have been a signal that it was necessary to review the ROE estimation methodologies that Staff relies on to establish their recommended ROE.

Furthermore, Staff's mean and median DCF results are well below the average authorized ROE for gas distribution companies since 2014 of 9.65 percent. As shown on page 2 of Exhibit___(FP-15), the individual company DCF results range from 6.32 percent to 11.25 percent. Regulators in other jurisdictions have determined that it is appropriate to exclude low and high outliers. For example, in a 2014 decision involving Connecticut Light & Power, the Public Utility Regulatory Authority ("PURA") in Connecticut acknowledged that market conditions resulted in some very low DCF results and, therefore, increased the lower threshold to 375 basis points above the cost of debt, stating:

> In the case of the electric industry, the Authority implements more stringent screening criteria as there is a large universe of publicly traded electric utilities. In addition to the initial proxy group screening criteria discussed above, the Authority set an acceptance criterion relative to the individual DCF results. With the changing market conditions, the Authority finds the screening mechanism for implausibly high and low DCF results to be beneficial. Regarding the low side threshold, the Authority finds as reasonable, the concept that equity is more risky than debt. Traditionally, the Authority's method has been to add 100 basis points to the average Mergent Public Utility Bond yield as its low end to screen individual DCF estimates. The cost of debt benchmark consists of the most current effective cost of long-term debt rate for each Authority Peer Group company using the latest Mergent Bond Guide as the source for the corporate bond yield averages. With the continuous decline in interest rates combined with the decrease in stock prices and growth rates, the Authority observed the individual DCF estimates also have fallen.
>
> The latest Mergent Bond Record, August 2014 edition indicates that over the time period this rate proceeding commenced, the average Aa Public Utility Bond yield ranged from 4.23% to 4.07%. Applying the concept that equity is more risky than debt, the Authority finds it reasonable to increase the minimum basis point threshold above the cost of debt from 100 basis points to 375 basis points.[55]

As shown in Exhibit AEB-19, if the Commission were to apply the Connecticut PURA thresholds for low and high outliers to the Staff Panel's DCF analysis, the mean DCF result would increase from 8.29 percent to 9.71 percent.

[55] The State of Connecticut Public Utilities Regulation Authority Decision, Docket No. 14-05-06 Application of the Connecticut Light and Power Company to Amend Rate Schedules, December 17, 2014, p. 129.

Q. WHAT ARE THE DIFFERENCES BETWEEN YOUR APPLICATION OF THE DCF MODEL AND STAFF'S APPROACH?

A. The most significant difference between my application of the DCF model and Staff's approach is the growth rates we use in our respective analyses. I have used a consensus of analysts' EPS growth rates for the proxy group companies as the near-term growth rate, and an estimate of growth in the overall economy for the long-term growth rate. This mitigates the uncertainty associated with forecasting individual companies' growth rates over very long time horizons. By contrast, Staff uses more limited dividend growth projections from a single source (*i.e.*, Value Line) for the near-term growth rate, and a "sustainable growth rate" for the long-term growth rate. Staff states that it is "highly unlikely that investors would rely exclusively on the earnings per share growth rate forecasts of Wall Street analysts in determining short-term dividend projections."[56]

Q. DO YOU AGREE WITH STAFF'S PREFERENCE FOR DIVIDEND GROWTH RATES RATHER THAN EARNINGS GROWTH RATES AS THE NEAR-TERM GROWTH RATE IN THE DCF ANALYSIS?

A. No, I do not. As discussed in my Direct Testimony, dividend growth is fundamentally driven by earnings growth.[57] While the model is, indeed, called the "Discounted Cash Flow" model, the cash flows it refers to are those an

[56] Prepared Testimony of Staff Finance Panel, at 81.
[57] Direct Testimony of Ann E. Bulkley, at 50.

investor can expect to receive during the time they own the stock. Those cash flows are quarterly dividend payments plus any capital appreciation that occurs between the time when the stock is purchased and when it is sold. Dividend payments and capital appreciation are both a function of earnings per share ("EPS"), which is ultimately what determines the return on equity to the investor. As discussed in my Direct Testimony, dividends are based on management decisions related to cash management and other factors, and therefore dividend growth rates are less likely to accurately reflect investors' growth expectations than earnings growth rates.[58]

I have relied on earnings growth because earnings are the fundamental determinant of a company's ability to pay dividends. As noted by Brigham and Houston:

> Growth in dividends occurs primarily as a result of growth in earnings per share (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE).[59]

Q. IS THERE EVIDENCE INDICATING THAT INVESTMENT ANALYSTS PRIMARILY REPORT AND RELY ON EARNINGS GROWTH ESTIMATES?

A. Yes, investment analysts predominantly report EPS growth projections. In a survey completed by 297 members of the Association for Investment

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58 *Id.*, at 50.

59 Eugene F. Brigham and Joel F. Houston, *Fundamentals of Financial Management*, at 317 (Concise Fourth Edition, Thomson South-Western, 2004).

Management and Research, the majority of respondents ranked earnings as the most important variable in valuing a security (more important than cash flow, dividends, or book value).[60]

Academic research also supports the use of EPS growth estimates. A 2002 study in the *Journal of Accounting Research* examined "the valuation performance of a comprehensive list of value drivers" and found that "forward earnings explain stock prices remarkably well" and were generally superior to other value drivers analyzed.[61] A 2012 study from the journal *Contemporary Accounting Research* found that sell-side analysts with the most accurate stock price targets were those whom the researchers found to have more accurate earnings forecasts.[62]

Q. WHAT IS YOUR RESPONSE TO STAFF'S CONCERN THAT EARNINGS PER SHARE GROWTH RATES DO NOT TAKE INTO CONSIDERATION THE IMPACT OF DIVIDEND PAYOUT POLICIES ON FUTURE GROWTH RATES?[63]

A. Staff's position ignores one of the basic underlying assumptions of the DCF model (i.e., a stable dividend payout ratio). While the Multi-Stage DCF model assumes that the growth rates change in each stage of the analysis, within each stage of the model the requirements of the Constant Growth form of the DCF

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60 Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", Financial Analysts Journal (July/August 1999).

61 Liu, Jing, et al., "Equity Valuation Using Multiples," Journal of Accounting Research, Vol. 40 No. 1, March 2002.

62 Gleason, C.A., et al., "Valuation Model Use and the Price Target Performance of Sell-Side Equity Analysts," *Contemporary Accounting Research.*

63 Prepared Testimony of Staff Finance Panel, at 80.

model continue to apply, including a stable dividend payout ratio. To assume otherwise would require an individual forecast of growth rates in each year of the analysis, which would be inconsistent with both regulatory and investment community practice.

Furthermore, Staff has provided no evidence that the dividend payout ratios for the companies in its proxy group or my CUPG or NGPG are out of line with historical averages. In fact, as shown on Exhibit__(FP-15), page 2 of 2, the average and median dividend payout ratios (calculated as 1 – the retention ratio) for the companies in Staff's proxy group are approximately 60 percent, which is generally consistent with the long-term historical average for regulated electric and gas utilities. Therefore, I see no basis for Staff's concern regarding the use of earnings growth rates

Q. ACCORDING TO STAFF, THE VALUE LINE GROWTH RATES DO NOT REPRESENT THE VIEWS OF A SINGLE ANALYST BECAUSE EACH REPORT IS REVIEWED BY MULTIPLE ANALYSTS BEFORE THEY ARE POSTED.[64] WHAT IS YOUR RESPONSE?

A. I do not agree that the Value Line quality control process is equivalent to a consensus earnings growth rate forecast from sources such as Zack's or Thomson First Call. Staff provides a letter from Value Line describing the development of its growth projections, as Exhibit ___(FP-21). Value Line states that each company it covers is assigned to a lead analyst who is responsible for building the

[64] *Id.*, at 83-84.

coverage model for that company. Specifically, the letter states, "[e]ach stock in The Value Line Investment Survey is assigned to a specific analyst."[65] The letter goes on to report the quality control procedures applied to the analyst's report. Nowhere in the letter, titled "Quality Control Procedures," does Value Line describe a process whereby multiple independent evaluations are performed and then averaged together to form a consensus view. Furthermore, it is my understanding that unlike other analysts, Value Line analysts do not actively participate in earnings calls or maintain an ongoing dialogue with NFG management. Therefore, it is possible that Value Line does not have the same in-depth understanding that other analysts include in consensus estimates, and that the Value Line analysts may not cover each of the companies in the same depth as other industry analysts.

While I agree that Value Line is a trusted source for investment professionals, it is not the only tool that investors rely on to make decisions. There are additional data sources readily available that compile the consensus viewpoints of multiple brokerage analysts; it is reasonable to expect that investors also consider that information. In fact, there have been studies performed comparing Value Line and I/B/E/S analyst earnings forecasts in terms of accuracy, rationality and as proxies for market expectations. In 2001, a study concluded that "I/B/E/S forecasts were superior, as explained by the combination of I/B/E/S's timing

[65] Exhibit __ (FP-21).

advantage and the mitigation of idiosyncratic error through consensus building."[66] Furthermore, the I/B/E/S long-term forecasts were less biased and more accurate.[67]

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH STAFF'S SUSTAINABLE GROWTH RATE AS THE LONG-TERM GROWTH RATE IN THE MULTI-STAGE DCF MODEL.

A. I have two main concerns with Staff's sustainable growth rate. First, while Staff asserts that its calculation of the sustainable growth rate represents a measure of long-term growth for the period 2021 and beyond[68], the inputs to its calculation are, for the most part, shorter-term estimates for the period 2020 and earlier. For example, the "b * r" component of Staff's sustainable growth rate is derived from Value Line forecasts that only extend through 2020. Therefore, Staff's long-term growth rate estimate reflects, at best, one analyst's forecast of only the very early years of the second stage of Staff's DCF model, which theoretically extends into perpetuity. In contrast, my estimate of long-term GDP growth reflects inflation projections through 2040 and considers overall measures of economic growth.[69] Second, Staff's sustainable growth rate relies on Value Line's estimate of each proxy company's ROE, as the "r" in the "b * r" component of his growth rate is the expected ROE. This introduces an element of circularity into Staff's

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66 Ramnath, Sundaresh, Rock, Steven, Shane, Philip, "Value Line and I/B/E/S Earnings Forecasts, November 8, 2001, at 1.

67 *Id*.

68 Prepared Testimony of Staff Finance Panel, at 56.

69 Direct Testimony of Ann E. Bulkley, at 54-55.

calculation. In addition, based on Exhibit __ (FP-15), the mean and median ROE assumed in Staff's calculation in 2020 are 10.77 percent and 10.27 percent, respectively. The range presented by the mean and median ROE used to calculate Staff's sustainable growth rate is higher than the range of ROEs established in my analysis for my proxy group companies (*i.e.*, 9.65 percent to 10.20 percent).[70] It cannot be reconciled, however, with Staff's recommended ROE of 8.60 percent, and especially with its 8.29 percent mean DCF result.

Q. HAS ANY OTHER REGULATORY COMMISSION RECENTLY ABANDONED THE USE OF THE SUSTAINABLE GROWTH RATE IN THE DCF MODEL?

A. Yes. In Opinion No. 531, the FERC changed its approach on the DCF methodology to be applied in public utility rate cases.[71] In summary, the FERC adopted the same two-step DCF methodology it has employed in gas and oil pipeline rate proceedings since the mid-1990s, in place of the one-step methodology previously used. The FERC's two-stage DCF approach does not rely on a retention growth calculation, and instead incorporates a long-term growth projection equal to GDP. The FERC justified its change on several grounds, but as is relevant in this proceeding, it determined that both a short-term and long-term growth rate should be incorporated into the DCF calculation for public utilities. The FERC explained that its previous approach for electric

[70] *Id*., at 68.
[71] Opinion No. 531 147 FERC ¶ 61,234 (June 19, 2014).

utilities, using a single-stage DCF model, based on a short-term retention growth rate, was established at a time when electric utilities were just beginning the process of restructuring and that in the Commission's view investors would place limited weight on long-term growth projections.[72] However, the FERC in revisiting its approach for electric utilities, finds that there is no longer reason to distinguish between gas pipelines and electric utilities in its DCF methodologies, and it has chosen to align its approach.

Q. DID THE FERC SPECIFICALLY ADDRESS THE RELEVANCE OF A SUSTAINABLE GROWTH RATE SIMILAR TO STAFF'S?

A. Yes. When intervenors challenged the use of analyst earnings growth rates as the short term growth rate as opposed to a retention growth rate, the FERC rejected that argument, stating:

> We also reject Petitioners' argument that the Commission should have used the "br+sv" growth rate as the short-term growth rate in the two-step DCF methodology. While the "br+sv" growth formula relies on short-term Value Line projections of five years or less for the various inputs to the formula, it seeks to estimate a company's "sustainable growth rate."
>
> For that reason, although the Commission has stated that the formula "only produces a projection of short-term growth, similar to the IBES projections," the Commission finds the formula unreasonable for use as the short-term growth projection in the two-step DCF methodology. By seeking to estimate a "sustainable growth rate," the "br+sv" growth formula also contains some elements of a long-term growth projection, in addition to a short-term growth projection, and

[72] Retention growth is a key element of Staff's sustainable growth rate.

> thus is inappropriate for use as a purely short-term growth projection in a two-step DCF methodology.
>
> The Commission adopted the two-step DCF methodology because, among other reasons, its incorporation of a long-term growth projection in the cost of equity calculation would have the effect of ascribing sustainable long-term growth to all members of a proxy group. Thus, the Commission's adoption of the two-step DCF methodology accomplishes what the use of the "br+sv" formula was intended to accomplish.[73]

Q. HOW DO YOU RESPOND TO STAFF'S OPPOSITION TO YOUR RELIANCE ON HISTORICAL AVERAGES OF REAL GDP GROWTH TO APPROXIMATE FUTURE ECONOMIC ACTIVITY?

A. I disagree with Staff's position that historical averages "are poor indicators of future economic activity."[74] As discussed in my Direct Testimony, based on current and recent market conditions, the use of historical real GDP growth is more appropriate than using a current projection of real GDP growth.[75] Economists have reviewed historical growth patterns related to severe financial crises and have concluded that estimates of GDP growth have generally been understated in the decade following severe financial crises. Specifically, the financial crisis and recession that began in 2007 were qualitatively different from most other U.S. economic downturns, which were followed by a rapid return to pre-recession overall output growth levels. In that regard, the current U.S.

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[73] Opinion No. 531-B, 147 FERC ¶ 61,234 Order on Rehearing (March 3, 2015) at para.77.
[74] Prepared Testimony of Staff Finance Panel, at 86.
[75] Direct Testimony of Ann E. Bulkley, at 55-58.

economic growth situation is similar to that following the two most severe economic events in U.S. history (*i.e.*, the 1929 stock market crash and the 1973 oil shock). Economists who have examined the repercussions of those two historical crises (and similar severe financial crises in other countries) have found that GDP growth rates tended to be lower during the decade following such events.[76] Therefore, it would not be appropriate to assume that current projections of GDP growth are representative of long-term GDP growth starting in 2027 and continuing for the next 200 years.

Q. HAVE YOU PERFORMED AN ANALYSIS OF HISTORICAL GDP GROWTH RATES?

A. Yes. I compared the average real GDP growth in the first ten years following the two historical economic crises most comparable to the recent financial crisis (*i.e.*, the 1929 stock market crash and the 1973 oil shock) to the average real GDP growth in the next two decades following each crisis (*i.e.*, eleven to 30 years after the events). I did the same for each of the twentieth-century U.S. recessions for which sufficient data are available. My findings are presented in Table 2.

[76] *See*, Reinhart, Carmen M. and Vincent R. Reinhart, "After the Fall," NBER Working Paper 16334, September 2010, in Federal Reserve Bank of Kansas City Economic Policy Symposium Volume, *Macroeconomic Challenges: The Decade Ahead* at Jackson Hole, Wyoming, on August 26-28, 2010, at 2.

Table 2: Real GDP Growth Rates Following U.S. Economic Downturns[77]

Event	Compound Average Real GDP Growth Rate		
	Decade Following Crisis	Next Two Decades	Difference (Basis Points)
Major Economic Crises			
1929 Stock Market Crash	2.06%	4.72%	266
1973 Oil Shock	2.55%	3.39%	83
Other Recessions			
1937	6.68%	4.15%	-253
1945	3.77%	3.59%	-18
1948	3.79%	3.95%	16
1953	3.60%	3.23%	-37
1957	4.84%	3.13%	-170
1960	4.41%	3.28%	-112
1969	3.57%	3.01%	-56
1980	3.32%	2.45%	-88
1981	3.52%	2.62%	-90

Table 2 shows that real GDP growth in the first ten years following the 1929 stock market crash and the 1973 oil shock was substantially lower than real GDP growth in the next two decades following each event. In contrast, eight out of the nine other twentieth century U.S. economic downturns analyzed showed the opposite pattern. In light of the academic research cited above and the findings presented in Table 2, it is reasonable to believe that current projections of real GDP growth are under-stated because they are based on recent trends. For that

[77] Real GDP data are from the U.S. Bureau of Economic Analysis. The years in which each recession started are from the National Bureau of Economic Research ("NBER"), "US Business Cycle Expansions and Contractions," available at http://www.nber.org/cycles.html. Note that this table excludes the three most recent recessions, which started in 1990, 2001, and 2007 owing to a lack of sufficient data for GDP growth in the following years to calculate comparable long-term GDP growth rates.

reason, the most reasonable way to forecast long-term GDP growth is to assume a return to long-term historical rates of real GDP growth and to estimate long-term nominal GDP growth based on market-based, long-term inflation estimates.

Q. STAFF EXPRESSES CONCERN WITH YOUR USE OF HISTORICAL REAL GDP GROWTH. HAS STAFF RELIED ON HISTORICAL DATA IN ANY OF ITS ANALYSES?

A. Yes. For example, in its CAPM analysis, Staff rejects the use of Bloomberg Betas, which rely on a two-year historical estimate of the relative risk of a company and the overall market because this calculation introduces "short-term volatility". Staff instead relies exclusively on Value Line Betas that rely on a five-year historical estimate to establish that relationship. Therefore, in this case, Staff is relying on a longer historical time period than the Bloomberg calculation. Staff also relies on historical average interest rates on 10-year and 30-year Treasury bonds as the risk-free rate in its CAPM analysis, rather than considering projected Treasury bond yields.

Q. WHAT DO YOU CONCLUDE ABOUT THE RESULTS OF THE DCF MODELS UNDER CURRENT MARKET CONDITIONS?

A. As explained in my Direct Testimony, the DCF models are not producing reasonable results under current market conditions as a result of low dividend yields and high stock valuations.[78] Chart 3 demonstrates that low dividend yields and high valuations on utility shares, could result in an underestimation of the cost

[78] Direct Testimony of Ann E. Bulkley, at 35-38.

of equity using the DCF model, especially if those high valuations and low dividend yields are not sustainable in the future as reported by Value Line. For these reasons, I believe it is appropriate to afford an appropriate weight to the results of other ROE estimation methodologies. In particular, it is appropriate to give greater weight to the CAPM, which can be adjusted to reflect investors' expectations of interest rates and therefore provides a better indicator of investors' expected return during the period that the rates established in this case will be in effect.

Q. USING THE FERC'S METHODOLOGY FOR SELECTING THE APPROPRIATE COST OF EQUITY FROM THE RANGE OF DCF RESULTS, AS ADOPTED IN OPINION NO. 531, WHAT WOULD BE THE DCF ESTIMATE USING STAFF'S PROXY GROUP?

A. Given the anomalous conditions in capital markets that are causing concern with the results produced by the DCF model, the FERC has determined that the reasonable cost of equity is the midpoint between the midpoint and high DCF results for the proxy group. The Staff Panel indicates that the range of results using Staff's DCF methodology and proxy group is 6.32 percent to 11.25 percent.[79] The midpoint of that range of results is 8.79 percent. Applying the FERC's methodology in Opinion No. 531 to the range of results produced by Staff's DCF analysis, the midpoint between the midpoint and high DCF results is

[79] Prepared Testimony of Staff Finance Panel, at 96.

10.02 percent, which is 173 basis points higher than Staff's DCF model result and 142 basis points higher than Staff's recommendation.

4. APPLICATION OF THE CAPM

Q. PLEASE SUMMARIZE STAFF'S APPLICATION OF THE CAPM.

A. Staff develops its estimate of the risk-free rate of 2.16 percent by using a recent three-month average of 10-year and 30-year Treasury bond yields. For the Beta estimate, Staff uses the median Value Line Beta for its proxy group of 0.70. To estimate the market risk premium, Staff subtracts the risk-free rate estimate from an average of the forecast returns for the S&P 500 from Merrill Lynch's April, May and June 2016 Quantitative Profiles. Staff also develops a Zero-Beta CAPM using similar inputs as the traditional CAPM analysis, but using a market risk premium based on weighting the Beta times the market risk premium by 0.75 and the market risk premium itself by 0.25. Staff's CAPM analyses produce ROE estimates of 8.31 percent (CAPM) and 8.97 percent (ECAPM). Staff relies on the average of these two CAPM analyses of 8.64 percent and weights that result by one-third in the formulation of its overall ROE recommendation.

Q. PLEASE COMMENT ON THE REASONABLENESS OF STAFF'S CAPM RESULTS.

A. Staff's results of 8.31 percent (CAPM) and 8.97 (ECAPM) percent are well below the comparable returns that are available to equity investors for gas distribution companies with commensurate risk. Since 2014, the average authorized ROE for gas distributors has been 9.65 percent. Furthermore, Staff's CAPM result of 8.31

percent has never been observed as an authorized ROE for a gas distribution company in at least the past 25 years.

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR APPLICATION OF THE CAPM AND STAFF'S APPLICATION OF THIS MODEL?

A. Because the estimation of the ROE is a forward-looking concept, and the ROE that is authorized in this case will be in effect for some period in the future, my analysis appropriately considers both the recent historical risk-free rate and the projected risk-free rate. The analysis presented in my Direct Testimony also relies on Bloomberg estimates of Beta that reflect more recent market conditions. Finally, I estimate the market risk premium based on the difference between the return on large company stocks, as measured by the S&P 500 and the yield on 30-year Treasury bonds. This approach is consistent with the methodology recently approved by the FERC in Opinion Nos. 531 and 531-B.

Q. STAFF CHALLENGES YOUR REASONING FOR USING 30-YEAR TREASURY BOND YIELDS RATHER THAN THE AVERAGE OF 10-YEAR AND 30-YEAR TREASURY BOND YIELDS. WHAT IS YOUR RESPONSE?

A. Staff's rationale for relying on 10-year and 30-year Treasury bond yields in its CAPM analysis is that it is consistent with the approach the Commission has relied on in prior cases, and the use of these securities reflects the expectations of

utility investors who have "intermediate and long-term investment horizons."[80] I disagree with Staff's rationale and note that Staff did not address evidence that was introduced on this topic in my Direct Testimony. In that testimony I noted that, Morningstar states that "the horizon is a function of the investment, *not the investor*."[81] The use of the 30-year Treasury bond yield as the risk-free rate is consistent with the investment horizon for electric and natural gas utility assets, which represent long-duration investments. Taking Staff's rationale to the limits, an investor who plans to hold a position in a utility equity share for only six months would use a certificate of deposit rate to evaluate the potential return. That is clearly not the case for any rational investor considering return requirements.

Q. HAS ANY OTHER REGULATORY COMMISSION COMMENTED ON THE APPROPRIATE SECURITY TO USE AS THE RISK-FREE RATE IN THE CAPM?

A. Yes. In Opinion No. 531, the FERC relies on the yield on the 30-year Treasury bond, stating:

> As noted above, the 30-year U.S. Treasury bond yields are a generally accepted proxy for the risk-free rate in a CAPM analysis, and are also considered superior to short- and intermediate-term bonds for this purpose.[82]

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80 *Id*., at 62.

81 Direct Testimony of Ann E. Bulkley, at 64.

82 FERC Order 531-B at para 114. Citing also to Roger A. Morin, New Regulatory Finance 151-152 (Public Utility Reports, Inc. 2006) ("the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM and Risk Premium methods.").

Q. WHY SHOULD PROJECTED TREASURY BOND YIELDS BE CONSIDERED IN THE CAPM ANALYSIS?

A. As discussed in my Direct and Rebuttal Testimonies, confirmed by the FERC in Opinion No. 531 and the recent MISO decision, and recognized by Staff, the low interest rate environment has affected the results of the ROE estimation models. Given these "anomalous" capital market conditions, I disagree with Staff's position that "current rates are the best indicator of future rates, as they are based on the latest available information to investors."[83] Just as investors reasonably consider actual and projected growth rates for individual companies, they also consider both current and projected yields on Treasury bonds. Thus, Staff's position on this topic is not only incorrect, but inconsistent with its own recognition of unusual current market conditions.

Q. IS STAFF'S POSITION REGARDING THE USE OF CURRENT INTEREST RATES CONSISTENT WITH OTHER ELEMENTS OF ITS CAPM ANALYSIS?

A. No, in the estimation of the market risk premium, Staff states that the *ex-post* method to derive the market risk premium is "fundamentally flawed because *ex-post* MRP's are based on the faulty premise that past performance is a valid proxy for expectations regarding future results."[84] Thus, Staff's position that it is reasonable to consider forecasts of the market risk premium in the CAPM directly

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83 Prepared Testimony of Staff Finance Panel, at 91-92.
84 *Id.*, at 65-66.

contradicts their position that interest rate forecasts should not be employed in the CAPM. Staff's opposition to the use of interest rate forecasts is particularly troublesome when one recognizes that interest rates are expected to increase over the period during which rates will be in effect. As discussed previously, consensus forecasts indicate that interest rates will increase substantially from artificially low levels in the near and longer-term as the Federal Reserve pursues its stated policy of normalizing rates. It is reasonable to expect that investors can and do consider this information, as they do other market projections. Therefore, it is reasonable, and consistent with Staff's position regarding the calculation of the market risk premium, to rely on expectations of future interest rate conditions to the extent that those expected conditions differ from recent history.

Q. DOES STAFF ACCURATELY DESCRIBE YOUR DIRECT TESTIMONY WITH RESPECT TO THE USE OF 30-YEAR TREASURY BONDS IN THE CAPM?

A. No. Staff suggests that I concluded that "all utility equity investors have an investment horizon of 30 years."[85] Staff then states that this conclusion is unsubstantiated. Staff provides no citation for where this conclusion appears in my Direct Testimony.

[85] Prepared Testimony of Staff Finance Panel, at 91.

Q. WHAT IS YOUR TESTIMONY WITH RESPECT TO THE USE OF THE YIELD ON 30-YEAR TREASURY BONDS AS THE RISK-FREE RATE?

A. As discussed in my Direct Testimony, it is important to select the term (or maturity) that best matches the life of the underlying investment.[86] I also cite to Morningstar, which notes that the Treasury security relied on should match the time horizon of what is being valued, and that the time horizon is a function of the investment, not the investor. I do not state that equity investors have an investment horizon of 30 years, nor does my testimony suggest that this would be a relevant factor in determining the appropriate security for the risk-free rate even if investors' time horizons were that long.

Q. WHY DOES STAFF DISAGREE WITH THE USE OF BLOOMBERG BETAS IN YOUR CAPM ANALYSIS?

A. Staff asserts that Bloomberg employs shorter time periods for its calculation of Beta than does Value Line, which Staff testifies can cause "notable variances in the beta results."[87]

Q. IS IT REASONABLE TO RELY ON THE BLOOMBERG BETAS?

A. Yes. It is reasonable to consider several measures of market conditions in estimating the ROE. As discussed in my Direct Testimony, Bloomberg Betas are widely used, and because they are based on a two-year period as compared to

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86 Direct Testimony of Ann E. Bulkley, at 64.
87 Prepared Testimony of Staff Finance Panel, at 64.

Value Line's five-year period, Bloomberg Betas rely on more recent market data.[88]

Q. PLEASE SUMMARIZE STAFF'S CONCERN WITH YOUR ESTIMATION OF THE MARKET RISK PREMIUM.

A. Staff contends that the use of the Constant Growth DCF model to develop the market return on the S&P 500 is not appropriate because the companies in the S&P 500 cannot sustain their three-to-five year growth rates in perpetuity.[89]

Q. WHAT IS YOUR RESPONSE?

A. My calculation of the market risk premium is based on the return on the broader market, as measured by the S&P 500 less the return on a risk-free instrument. The S&P 500 is an index that includes the largest 500 companies by market capitalization. Over time, the specific companies that are included in the S&P 500 Index will vary, but investor expectations of growth and overall return for the index as a whole may not, based on the selection process involved in the index. This is due to the fact that companies within the index with lower growth rates are more likely to drop out of the index and be replaced by companies with higher growth rates. Therefore, there is evidence supporting the reasonableness of my assumption that the average growth of the index could be sustainable in the long-run.

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[88] Direct Testimony of Ann E. Bulkley, at 66.
[89] Prepared Testimony of Staff Finance Panel, at 92-93.

Q. HAVE OTHER COMMISSIONS SUPPORTED THE USE OF A CONSTANT GROWTH DCF MODEL TO ESTIMATE THE MARKET RETURN?

A. Yes. In Opinion 531-B, the FERC addresses the use of the Constant Growth DCF model to estimate the market return in the calculation of the market risk premium used in the CAPM analysis. In that opinion, FERC specifically addresses intervenor concerns that the growth rate of the S&P 500 is not sustainable, stating:

> While an individual company cannot be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable.[90]

The methodology and assumptions used in my CAPM analyses are consistent with those adopted by the FERC for estimating the total market return and the market risk premium.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE CAPM ANALYSIS?

A. In principle, Staff and I agree that the development of the inputs and assumptions for the CAPM should be done on a forward-looking basis, and that ex-post analysis can be flawed under certain circumstances. Furthermore, both our CAPM analyses contain some historical data where we believe it to be the best estimate in current market conditions. In order to minimize the differences between our CAPM analyses I also have accepted Staff's reliance on Value Line

[90] FERC Opinion 531-B, at para. 113.

Betas in this case. The two remaining areas of disagreement in the CAPM analysis are Staff's refusal to consider interest rate projections along with current rates as the CAPM risk-free rate and its criticism of my market risk premium calculation.

5. BUSINESS RISKS AND REGULATORY ENVIRONMENT

Q. DID STAFF TAKE INTO CONSIDERATION THE BUSINESS RISKS AND REGULATORY ENVIRONMENT OF DISTRIBUTION IN ITS ROE RECOMMENDATION?

A. Staff does not comment on the business risk of Distribution other than to say that 73 percent of the Company's revenues are either subject to deferrals or true-ups such as gas cost adjustments, purchased gas adjustment, a revenue decoupling mechanism, and pension and OPEB costs.[91] Staff states that there is a significant reduction in Distribution's risk under either a one-year or multi-year rate plan.[92] However, Staff does not compare the Company's business or regulatory risks to the proxy group companies. Thus, there is no record evidence supporting any statements by Staff regarding the relative risks of Distribution versus its proxy group. This is a very important omission because, while the ROE is estimated using the proxy group results as a surrogate for the investor required return, a complete ROE analysis must consider the business risks of the subject company relative to the proxy group.

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[91] Prepared Testimony of Staff Finance Panel, at 19.
[92] *Id.*, at 19-20.

Q. DO YOU AGREE WITH STAFF THAT BECAUSE 73 PERCENT OF THE COMPANY'S REVENUES ARE SUBJECT TO TRUE-UPS OR DEFERRALS THERE IS A SIGNIFICANT REDUCTION IN DISTRIBUTION'S RISK?

A. No, I do not. First, since the ROE is established based on the expected returns for a proxy group of comparable companies, the analysis of business risk in the ROE determination is a comparative analysis. Therefore, the relevant question is not how much of the Company's risk has been reduced, but rather how much risk does Distribution have relative to the comparison group. In that regard, Staff has provided no record evidence. Staff's analysis, which suggests that 73 percent of the Company's revenues are subject to true-ups and deferrals, includes the recovery of gas costs, which are a pass-through cost for nearly all natural gas distribution companies. Natural gas costs are the single largest cost for a natural gas distribution company. Therefore, the inclusion of natural gas costs in Staff's analysis has the effect of overstating Distribution's risk-mitigating measures versus the proxy group. Furthermore, since nearly all natural gas distribution companies are allowed to pass through gas costs directly to customers, there is no difference in risk between Distribution and the proxy companies on the recovery of this cost. As noted previously, Staff has not provided any record evidence as to the level of recovery or true-up of Distribution's remaining operating costs as compared with the comparable group to assess Distribution's relative risk profile.

In addition, the Staff Policy Panel is recommending several changes that would increase the potential negative revenue adjustments for customer service, gas safety, potential penalties for customer service terminations for failure to pay, and Staff's proposal to remove existing measures for customer service where the Company does well (e.g., appointments kept) and increase the weighting of measures that are essentially outside of the Company's control (e.g., customer complaints) also increase risk. These proposals, if adopted, would have the effect of raising the business risk of Distribution.

Q. DID YOU CONDUCT ANY ANALYSIS OF THE RISK OF YOUR PROXY GROUP AS COMPARED WITH DISTRIBUTION?

A. Yes. As discussed in my Direct Testimony, I examined two rankings performed by the investment community of U.S. regulatory commissions.[93] Regulatory Research Associates ("RRA") accords New York an "Average/2" rating, which is in the exact middle of RRA's ranking system. S&P ranks New York 34th out of 53 regulatory jurisdictions (including Federal, the District of Columbia, and two Texas state regulators) for credit supportiveness, suggesting that New York is below average when compared to other U.S. regulatory jurisdictions. Neither of these results support Staff's contention that New York regulation makes New York utilities less risky than comparable groups of utilities. I also note that Staff did not provide record evidence to refute these rankings.

[93] Direct Testimony of Ann E. Bulkley, at 84.

Q. STAFF NOTES THAT REVENUE DECOUPLING MECHANISMS REDUCE DISTRIBUTION'S REVENUE RISK. HAVE YOU CONSIDERED THE EFFECT OF DISTRIBUTION'S REVENUE DECOUPLING MECHANISM ON THE REQUIRED ROE?

A. Yes, I have. I recognize that the Commission has implemented various revenue stabilization and cost recovery mechanisms, and that this Commission may have been an early adopter of these progressive forms of revenue stability and cost recovery. Over time, however, many jurisdictions have adopted some form of revenue decoupling and various cost recovery mechanisms to provide a reasonable opportunity to recover the utility's costs and earn the authorized ROE. Since the ROE recommendation is established for a company based on its risk relative to the proxy group, I reviewed the alternative rate mechanisms that have been implemented by the NGPG companies. As shown in Exhibit __ (AEB-12) to my Direct Testimony, approximately 66.7 percent of the jurisdictions where the NGPG companies operate have approved some form of revenue stabilization mechanism (i.e., formula rate plan, revenue decoupling mechanism, straight fixed-variable rate design) that breaks the link between revenues and volumetric use. In addition, the vast majority of the proxy group companies have been allowed to implement cost recovery mechanisms that provide for the recovery of prudently incurred costs between rate cases.[94] Furthermore, as shown in Exhibit

[94] Source: Regulatory Research Associates, Regulatory Focus, "Adjustment Clauses: A State-by-State Overview," August 22, 2016.

AEB-24, the CUPG companies also have many revenue stabilization and cost recovery mechanisms. On that basis, my conclusion is that Distribution has similar cost recovery protection as the companies in the CUPG and NGPG. Furthermore, Exhibit AEB-24 demonstrates that there is no systematic reduction in the ROE for operating utilities that have decoupling mechanisms or other cost recovery mechanisms.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING DISTRIBUTION'S BUSINESS RISK RELATIVE TO THE PROXY GROUP?

A. As discussed in my Direct Testimony, New York's relative regulatory rankings from a credit perspective, coupled with the heightened level of business risk faced by Distribution due to its capital spending plans, demonstrate that the Company's business risk is actually above average compared to the proxy companies due to the perceived instability of the New York regulatory environment. That elevated risk profile increases the importance of setting a return for Distribution that is within the range of reasonableness as established by the returns for the two proxy groups that I used in formulating my return recommendation.

Q. SINCE THE FILING OF YOUR DIRECT TESTIMONY, HAVE CREDIT RATING AGENCIES OFFERED RECENT OPINIONS ON NEW YORK REGULATORY RISK?

A. Yes. In a recent report "Assessing U.S. Investor-Owned Utility Regulatory Environments" S&P cited this Commission's Reforming the Energy Vision ("REV") proceeding as possibly increasing risk for utilities. S&P specifically

noted that the REV implementation could disrupt the way utilities make money and affect their ability to earn the authorized ROE. S&P cautioned that if the outcome was greater operating risk and no opportunity to earn greater returns, their assessment of the regulatory environment could change.[95] This suggests that the credit rating agencies are focused on regulatory changes that could cause significant financial changes for the regulated utilities. Staff's proposed ROE and equity ratio, and its unfounded approach to imposing such ratio, could constitute the very type of change that the credit rating agencies would view as a higher risk for the utility.

6. APPROPRIATE CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE THE DIFFERENCES BETWEEN THE STAFF PANEL'S RECOMMENDATION AND YOUR RECOMMENDATION REGARDING THE APPROPRIATE EQUITY RATIO FOR THE COMPANY.

A. The Company has appropriately proposed an equity ratio of 48.0 percent, which is consistent with the equity ratio that the Commission has consistently authorized for electric and natural gas utilities over the past several years. As discussed in my Direct Testimony, that equity ratio is below the average equity ratio of the proxy companies over the last four years and therefore is conservative.[96]

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95 Standard & Poor's Global Ratings Research, "Assessing U.S. Investor-Owned Utility Regulatory Environments", August 10, 2016 p. 3.

96 *Id*., at 87-89.

Staff is recommending that NFG's (the parent company) equity ratio of 42.3 percent also be used for Distribution rather than the 48.0 percent equity ratio requested by the Company. As support for its recommendation, Staff argues that NFG's involvement in unregulated activities increases the risk profile of the parent. In addition, as the Company Finance Panel discusses extensively in their rebuttal testimony, NFG has taken impairment charges for assets used in its exploration and production business. These "ceiling test" impairments are based on accounting rules that require it to make arbitrary assumptions, the most significant of which is the use of historical commodity prices in determining the value of their oil and natural gas reserves. Consequently, the impairments that NFG was required to recognize over the past two years do not reflect the ongoing profitability of its operations. These ceiling test impairments have significantly impacted NFG's capital structure, which now includes 42.3 percent common equity. Staff contends that if Distribution is allowed a higher common equity ratio than NFG, Distribution's ratepayers will be effectively subsidizing the unregulated business activities of NFG. Alternatively, Staff testifies that NFG and Distribution can resolve this concern by implementing ring-fencing provisions that insulate Distribution from NFG so that ratepayers are not harmed if NFG takes additional impairment charges that further reduce its consolidated equity ratio.

Q. DO YOU AGREE WITH STAFF'S RECOMMENDED CAPITAL STRUCTURE FOR DISTRIBUTION?

A. No, I do not. My disagreement with Staff's capital structure recommendation centers around three primary considerations. First, Staff's proposal denies Distribution a fair return by assigning an equity ratio that is far below the average actual or awarded equity ratios of Distribution's regulated peers. Second, the use of the consolidated capital structure that has been substantially affected by recent impairment charges unfairly penalizes Distribution for its parent's book capital structure. As the Company Finance Panel states, these impairments do not reflect the current value or ongoing profitability of their oil and gas assets and are subject to rules that the U.S. Securities and Exchange Commission ("SEC") admits are arbitrary in nature. The resulting capital structure is not reflective of how the parent has financed Distribution's operations in the past or how they will be financed in the future and does not accurately reflect the risk and financial characteristics of NFG or Distribution. Third, Staff's position is inconsistent with its most recently authorized equity ratio for Distribution and previous rationales and methodologies that have been used for authorizing the equity ratio of a utility in a consolidated holding company structure. Staff's capital structure proposal is unfairly punitive to Distribution and fails to satisfy the comparability requirement of the fair return standard.

Q. STAFF STATED THAT YOUR ANALYSIS DID NOT INCLUDE A REVIEW OF THE CAPITAL STRUCTURES OF THE REGULATED UTILITY OPERATING COMPANIES IN YOUR PROXY SAMPLES, BUT ONLY REPORTED THE CAPITAL STRUCTURES OF THE HOLDING COMPANIES OF THE REGULATED UTILITIES.[97] IS STAFF'S STATEMENT ACCURATE?

A. No. As shown in my Direct Testimony, Exhibits AEB-13 and AEB-14 reflect an average of the individual utility operating companies' capital structures associated with each proxy company. The equity ratios presented on those exhibits do not reflect the holding company capital structures, nor do they include capital structures of any unregulated operating companies. For example, the capital structure shown for Alliant Energy for 2014 of 48.75 percent is actually composed of the average of the two relevant Alliant-owned operating utilities, Interstate Power and Light Company (47.23 percent) and Wisconsin Power and Light Company (50.27 percent). As those exhibits demonstrate, the average 2014 capital structure for my CUPG was 54.32 percent, and for my NGPG was 56.87 percent. These comprise the actual capital structures of the utility operating companies at the end of fiscal year 2014. Updating the equity ratio data for 2015, results in an average capital structure for the CUPG of 54.94 percent and for the NGPG of 57.28 percent.

[97] Prepared Testimony of Staff Finance Panel, at 13.

Q. HAVE YOU CONDUCTED ANY ANALYSIS REGARDING RECENTLY AUTHORIZED EQUITY RATIOS OF THE UTILITY SUBSIDIARY COMPANIES IN YOUR PROXY GROUPS?

A. Yes, as indicated in Exhibits AEB-15 and AEB-16 of my Direct Testimony, the average awarded equity ratios were 51.01 and 52.42 percent for the CUPG and for the NGPG, respectively. As the data show, authorizing an equity ratio of 42.3 percent for Distribution while the rest of New York's utilities are allowed 48 percent, and while the proxy group allowed equity ratios average 51.01 percent for the CUPG and 52.42 percent for the NGPG, unfairly penalizes Distribution and puts the Company at a significant financing disadvantage relative to its peers. Staff's proposal for an ROE of 8.60 percent and its equity ratio of 42.3 percent subjects Distribution to much greater financial risk than other utilities in New York, without any justification that pertains to the stand-alone utility. Distribution provides excellent service quality at reasonable rates. There is absolutely no justifiable basis for Staff's punitive capital structure and return recommendations, especially when considering the Company's demonstrable efficiency and excellent service.

Q. WHY DOESN'T STAFF CONSIDER THE AVERAGE COMMON EQUITY RATIO OF THE UTILITY SUBSIDIARIES OF THE PROXY COMPANIES TO BE A REASONABLE COMPARISON FOR DISTRIBUTION'S CAPITALIZATION?

A. Staff states that "[t]he capital structures for utility subsidiaries of holding

companies may not reflect either rational capitalization policies, or actual common equity employed, and therefore may not be suitable for establishing a utility's rate of return."[98] Staff goes on to discuss the potential for double leverage where the parent company may finance the utility's equity with debt issued at the holding company.[99] Staff also states that it is inappropriate to use a subsidiary capital structure when the holding company parent has financed riskier competitive non-utility operations with less equity (and hence more debt) than would be required for these ventures to achieve the same credit rating as the utility subsidiaries.[100] Staff argues that unless the utility's credit rating is insulated from the risks of unregulated operations, "using the subsidiary capital structure would effectively require ratepayers of a lower-risk natural gas distribution company to subsidize its parent's riskier investments."[101]

Q. DOES STAFF'S RECOMMENDED EQUITY RATIO REFLECT A REASONABLE CAPITAL STRUCTURE FOR RATEMAKING PURPOSES FOR DISTRIBUTION?

A. No, it does not. Staff's proposal relies on circumstances that are entirely unrelated to Distribution and are not indicative of NFG's long-standing financial position or its likely position in the near future. Staff explains in its testimony that the parent company's capital structure has been subject to a number of recent impairment charges totaling approximately $2 billion. As discussed further in the

98 *Id.*, at 15-16.
99 *Id.*, at 16.
100 *Id.*
101 *Id.*

Company's Finance Panel rebuttal testimony, these charges related to the required non-cash asset write down by the exploration and production segment due to the sharp decline in crude oil prices from over $100 per barrel to a low of below $30 per barrel and for gas prices in the $2.00/Dth range. Prices have since experienced a significant recovery, but the assets cannot be written up to reflect their current value. Staff acknowledges that, in March 2015, NFG's equity ratio was 61.2 percent[102] and that the impairments reduced the parent company's book equity ratio to 42.3 percent. Clearly, the change in capitalization ratio is entirely the result of a temporary dislocation in commodity prices, and the impact of that on the arbitrary accounting rules required by the SEC, and does not reflect how the business operations of NFG or Distribution have been financed, nor does it reflect NFG's intention to maintain an investment grade financial profile going forward. These book accounting losses charged against NFG's consolidated equity should not be considered in determining rates for Distribution.

Q. DO YOU CONCUR WITH STAFF'S ASSERTION THAT USING THE COMMISSION'S AVERAGE AUTHORIZED EQUITY RATIO FOR UTILITY OPERATING COMPANIES OF 48 PERCENT FOR DISTRIBUTION WOULD EFFECTIVELY REQUIRE RATEPAYERS OF A LOWER-RISK NATURAL GAS DISTRIBUTION COMPANY TO SUBSIDIZE ITS PARENT'S RISKIER INVESTMENTS?

A. No, I do not. Staff argues that in cases where riskier competitive non-utility

[102] *Id.*, at 28.

operations are financed with less equity than would be required to maintain their credit ratings for the enhanced level of risk, a subsidy has occurred. However, as I have indicated above, the distinction that must be reiterated is that these companies were not financed with 42.3 percent equity and could not have been. NFG has historically held approximately 60 percent equity in its capital structure. It is only the result of these one-time, non-cash, impairments charged against the parent's equity – impairments calculated at the absolute nadir of oil and gas prices that have since recovered appreciably - that NFG's equity capitalization has fallen to the current percentage. There is no record evidence that any sort of subsidy has occurred between the regulated utility and the parent. To allow cross-subsidies between parent and subsidiary undermines the principle of stand-alone ratemaking.

Q. WHAT IS THE STAND-ALONE PRINCIPLE AND WHY IS IT IMPORTANT FOR RATEMAKING?

A. The stand-alone principle provides that the utility must be regulated as if it were a stand-alone entity, raising capital on the merits of its own business and financial characteristics. In this way, capital may be efficiently allocated, with each business segment earning a return based on its own unique set of risks and business characteristics regardless of affiliations within the holding company structure. Accordingly, the stand-alone principle would find that the existence of a holding company structure does not justify imputing an equity ratio onto the

utility that is materially different than what would have been awarded on its own merits and financial characteristics. Disallowing a portion of the utility's capitalization because it operates in a holding company structure, which includes affiliates that have suffered financial losses, effectively results in the comingling of utility equity with the unregulated subsidiaries.

Q. WHAT IS THE RESULT OF COMINGLING UTILITY EQUITY WITH ITS UNREGULATED UTILITIES?

A. The result is that utilities would be subject to the same risks as their unregulated affiliates and accordingly would have higher capital costs to compensate for such risks, ultimately subjecting rates and service quality to a higher level of risk. By imputing an equity ratio for Distribution that is common to the other Commission regulated utilities of like risk, we are able to keep separate the impacts of competitive ventures on the regulated utility. Alternatively, suggesting that Distribution maintain an equity ratio in line with the 42.3 percent ratemaking equity ratio proposed by Staff effectively increases the risk of Distribution. I question whether this is an outcome that either Staff or the Commission would support.

Q. STAFF PROPOSES THAT IF SUFFICIENT RING-FENCING WERE IN PLACE THE UTILITY WOULD NOT BE ABLE TO SUBSIDIZE ITS PARENT'S RISKY INVESTMENTS. DO YOU CONCUR?

A. First, there is no evidence that a measurable subsidy between the utility and the

parent has occurred. As discussed in the testimony of the Company Finance Panel, the 5.62 percent embedded cost of debt reflects the interest rate on issuances made prior to the downgrade. Furthermore, NFG has no plans to issue new debt during the rate year.

Q. HOW HAS THE CAPITAL STRUCTURE BEEN DETERMINED FOR DISTRIBUTION IN PRIOR RATE CASES?

A. When rates were reset for Distribution in 2013, Staff proposed and the Commission authorized a 48 percent equity ratio for Distribution, based on a subsidiary analysis, adjusted to reflect Distribution's risks relative to that of the capital structures of other major utility companies in New York.[103] The subsidiary adjustment is described as the Commission's tool for determining the capitalization of a regulated utility of a consolidated corporate structure. In the subsidiary adjustment, the Commission removes the unregulated capital from the capital structure of the consolidated entity at a rate of 60 percent equity and 40 percent debt to account for the higher level of risk in the unregulated segments. It then determines the resulting equity percentage from the remaining equity in the consolidated entity. In 2013, that adjustment resulted in a 57.1 percent equity ratio, which Staff claimed to be too high.[104] Staff then compared the capital structure of Distribution to eight major New York electric and gas distribution

[103] Prepared Testimony of: Temporary Rates Panel, Case 13-G-0136 (May 2013) at 74.
[104] *Id.*, at 76.

companies, for which the Commission had most recently determined an equity ratio of 48 percent (except for Keyspan Energy Delivery of Long Island which had authorized equity ratios of 45 percent).[105] The Staff also looked at ratings criteria for credit metrics to support its analysis. Ultimately the Staff recommended 48 percent equity for Distribution.[106]

Q. WHY IS STAFF'S PROPOSED 42.3 PERCENT EQUITY RATIO INCONSISTENT WITH PRIOR COMMISSION PRECEDENT AND PRIOR STAFF TESTIMONY?

A. As noted above, in prior cases, when the parent company equity ratio exceeded the authorized average of 48 percent, Staff proposed the use of the Commission's average authorized equity ratio for other utility operating companies, not the parent company equity ratio for the Company.[107] In this case, Staff now proposes to rely on the lower parent book equity ratio of 42.3 percent, reflecting E&P impairments to date, and not the 48 percent average authorized equity ratio for other New York regulated utilities. This represents a significant departure from the methodology that has been relied on in New York for establishing the capital structure and an inconsistent policy with respect to the equity ratio; relying on the parent's equity ratio when it was less than the imputed 48 percent, but ignoring that capitalization when it exceeds the hypothetical 48 percent.

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105 *Id.*, at 78-79.
106 NYPSC Decision, Case 13-G-0136 (May 2014) at 7.
107 Prepared Testimony of Temporary Rates Panel, Case 13-G-0136 (May 2013), at 76.

Q. DO CREDIT RATING AGENCIES VIEW UNPREDICTABILITY AS AN ADDITIONAL RISK?

A. Yes. Staff acknowledges that credit rating agencies "view unpredictability as an additional risk."[108] However, they have not considered how credit rating agencies or equity investors would react to an extraordinarily low authorized ROE and equity ratio for Distribution relative to recently approved ROEs and equity ratios for other gas distribution companies. Such a low ROE and equity ratio are likely to be viewed as punitive by rating agencies and investors and cause rating agencies to question the level of regulatory support being provided by the Commission. These consequences could extend to and be borne by all New York utilities and their customers. The credit rating agencies have indicated that unpredictability is a risk. In particular, in a recent report, S&P indicated that credit risk rises in jurisdictions that are undergoing major changes to the regulatory paradigm.[109] S&P also notes that major or frequent changes to the regulatory model invariably raise risk due to the possibility of future changes.[110] Based on this opinion, Staff's abrupt change in policy with respect to the proposed equity ratio for Distribution would likely be viewed as higher risk, not lower risk, as purportedly intended by Staff.

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108 Prepared Testimony of Staff Finance Panel, at 84.

109 S&P Global Ratings Research, Assessing U.S. Investor-Owned Utility Regulatory Environments (August 10, 2016), at 3.

110 *Id*.

Q. STAFF CLAIMS THAT AN EQUITY RATIO OF 42.3 PERCENT FOR DISTRIBUTION IS SUFFICIENT TO ACHIEVE CREDIT QUALITY. IS THIS THE ONLY RELEVANT CONSIDERATION?

A. No. As discussed in my Direct Testimony, the standards put forth in the precedent-setting cases *Hope* and *Bluefield* for determining the reasonableness of a utility's allowed ROE require that the Commission provide the Company with a return that is 1) adequate to attract capital at reasonable terms, 2) sufficient to support the financial soundness of the Company's operations, and 3) commensurate with returns on equity investments in enterprises having comparable risks.[111] Accepting, for the sake of argument, that Distribution could achieve credit quality and continue to attract capital with an equity ratio of 42.3 percent, it still must satisfy the standard of comparability for a fair return. Benchmarking against this Commission's recently authorized ROEs and national averages, Staff's proposed ROE and equity ratio are not aligned with equity ratios authorized for similar-risk utilities and accordingly do not meet the comparability standards established by *Hope* and *Bluefield*. Distribution should be awarded the same equity ratio as other New York utilities with comparable risk profiles. In the last rate proceeding, Distribution was held to a 48 percent equity ratio based on an analysis of Distribution's risk relative to the other New York utilities, despite that hypothetical equity ratio being lower than Distribution's actual equity

[111] Direct Testimony of Ann E. Bulkley, at 7.

ratio and lower than NFG's equity ratio.[112] In my opinion, a 48 percent equity ratio would be a reasonable outcome for Distribution, as I am aware of no shifts in Distribution's risk profile that would warrant a lesser equity ratio than its peers.

Q. STAFF RECOMMENDS AN ADJUSTMENT TO THE AUTHORIZED ROE OF 20 BASIS POINTS DUE TO THE ADDITIONAL FINANCIAL RISK THAT IS CREATED BY REDUCING DISTRIBUTION'S COMMON EQUITY RATIO FROM 48.0 PERCENT TO 42.3 PERCENT. DO YOU HAVE ANY COMMENTS ON THIS ADJUSTMENT TO THE AUTHORIZED ROE?

A. Yes. I agree with the Staff Panel that the proposed downward adjustment in Distribution's capital structure from 48.0 percent to 42.3 percent causes increased financial risk for the Company, which should be compensated through a higher authorized ROE. However, Staff's proposed adjustment of 20 basis points is not sufficient compensation. At an equity ratio of 48.0 percent and an authorized ROE of 8.40 percent, Distribution's weighted equity cost rate is 4.03 percent.[113] In order to achieve this same equity cost rate at an equity ratio of 42.3 percent, the authorized ROE for Distribution would need to be 9.53 percent. This would require an adjustment to Staff's ROE of 113 basis points.

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112 Prepared Testimony of: Temporary Rates Panel, Case 13-G-0136 (May 2013), at 78-79.

113 The equity cost rate is derived by multiplying the equity ratio by the equity cost rate, or 48.0% X 8.40% = 4.032%.

V. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT IS YOUR CONCLUSION REGARDING A FAIR RETURN ON EQUITY FOR DISTRIBUTION?

A. I continue to support a recommended return on equity for Distribution within the range of 9.65 percent and 10.20 percent. Nothing in the testimony of the Staff Finance Panel has caused me to change my recommendation. My recommendation considers the results of the DCF and CAPM methods, and the specific risks to which the Company is exposed. The recommended ROE of 10.20 percent is based on an equal weighting of the results of the DCF and CAPM, which is justified due to the effect of capital market conditions on the DCF model. The Company's requested ROE of 10.20 percent is reasonable and should be adopted.

Q. WHAT IS YOUR CONCLUSION REGARDING THE APPROPRIATE EQUITY RATIO FOR RATEMAKING PURPOSES FOR DISTRIBUTION IN THIS PROCEEDING?

A. I continue to support the Company's proposed 48 percent equity ratio as reasonable because it is within the range of the actual and authorized equity ratios of the utility subsidiaries of the proxy group companies. Further, it is also consistent with the Commission-authorized equity ratio for the other New York regulated utilities that are of similar risk as Distribution.

In contrast, Staff's proposed approach for establishing the Company's equity ratio represents a significant departure from Commission precedent, arbitrarily denies

Distribution the ability to earn a just and reasonable return and, together with Staff's ROE recommendation, results in a weighted equity cost rate of 3.64 percent for Distribution. Table 3 compares this figure to the equity cost rate of other relevant benchmarks.

Table 3: Equity Cost Rate Comparison

	ROE	Equity Ratio	Equity Cost Rate
Staff Recommendation	8.60%	42.30%	3.64%
NY Average (gas LDC since 2014)	9.07%	48.00%	4.35%
Bulkley CUPG from AEB-15	9.96%	51.01%	5.08%
National Avg (gas LDC since 2014)	9.65%	50.02%	4.83%

Furthermore, the increase in risk resulting from Staff's recommendation of an equity ratio that is 570 basis points below the average equity ratio of the other New York regulated utilities and 870 basis points below the average for the proxy companies is not nearly offset by the Staff's proposed adjustment to the ROE of 20 basis points. Finally, as discussed by Witness Reed, Staff's proposed ring-fencing provisions are not appropriate tools to be used in establishing just and reasonable rates, and are likely to be viewed negatively by credit rating agencies and equity analysts.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, AFFILIATION AND BUSINESS ADDRESS.

A. My name is Ann E. Bulkley. I am a Vice President of Concentric Energy Advisors, Inc. ("Concentric") located at 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. DID YOU PROVIDE DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, I did.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to respond to the supplemental testimony of the Department of Public Service Staff Finance Panel ("Staff" or the "Staff Finance Panel") regarding Staff's characterization of my testimony with respect to the regulatory rankings provided by Regulatory Research Associates ("RRA") and Standard and Poors ("S&P").

Q. IS THE STAFF FINANCE PANEL CORRECT THAT YOUR TESTIMONY CONCLUDES THAT THE NEW YORK COMMISISON'S REGULATORY RANKING IS "BELOW AVERAGE" BASED ON THE ANALYSES PRESENTED IN EXHIBITS__(AEB-10 AND AEB-11)?

A. No, it is not correct. As discussed in my direct testimony, Exhibit__ (AEB-10) demonstrates that the New York jurisdictional ranking based on the RRA rankings is "5.0" which was generally consistent with the proxy group average ranking of "5.26".[1] Exhibit___ (AEB-11) summarizes the S&P credit supportive rankings. I also recognize that the Commission is included in the Strong/Adequate category of the S&P credit supportive rankings, In my rebuttal testimony, however, I referred back to the analyses prepared in my direct testimony and noted that RRA accorded New York an "Average/2" ranking which is the middle of the RRA ranking system. I also noted that New York was ranked 34th out of 53 regulatory jurisdictions in the S&P credit supportiveness rankings, which is below the average in that analysis. My conclusions on this analysis were that these results do not support Staff's contention that New York regulation makes New York utilities less risky than the comparable group. The New York jurisdictional ranking of 34 is also below the proxy group average ranking of 25.57.[2]

Q. WHY IS IT APPROPRIATE TO APPLY A NUMERICAL RANKING FROM "1" TO "53" TO THE COMPANIES IN THE S&P CREDIT SUPPORTIVE REGULATORY RANKING?

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[1] *See* Direct Testimony of Ann E. Bulkley at p. 85.
[2] Ibid.

A. Based on the information provided by S&P, I understand the credit supportiveness matrix used by S&P to classified states into five categories from "Strong" to "Weak" and then rank ordered the states within those categories. Therefore, the federal jurisdiction is classified by S&P as the strongest with respect to credit supportiveness and Mississippi is the weakest. All other states are rank ordered within the five classifications. Therefore, it is appropriate to rely on a numerical ranking from "1" to "53".

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

A.L.J. LECAKES: Mr. Miller?

MR. BRUCE MILLER: Great. Thanks.

A.L.J. LECAKES: Okay. So I believe we are at Exhibit 10 for the affidavit and -- to the Bulkley exhibits.

MR. NICKSON: Attached to the Direct Testimony of Ms. Bulkley are 16 exhibits which were identified as AEB1 through AEB16. I would ask that they be marked as identification and attached to the Rebuttal Testimony of Ms. Bulkley are nine exhibits identified as AEB17 through AEB25 and I would also ask that they be marked for identification.

A.L.J. LECAKES: All right. So for the Exhibits AEB1 through AEB16 I have exhibit numbers 11 through 26. For the Exhibits AEB17 through AEB25, I have exhibit numbers 27 through 35. Okay. The next witnesses?

MR. NICKSON: The next witness is company witness Evan M. Crahen. Mr. Crahen -- Crahen, excuse me, prepared testimony entitled The Direct Testimony of Evan M. Crahen which consists of 19 pages of questions and answers. Mr. Crahen also prepared testimony entitled The Rebuttal Testimony of Evan M. Crahen which consists of 29 pages of questions and answer and I note, Your Honor, as we discussed earlier that there are both

confidential and public redacted versions of this testimony.

A.L.J. LECAKES: Right.

MR. NICKSON: And that I would ask that the direct and rebuttal testimony of Mr. Crahen be incorporated into the record as if given orally today.

A.L.J. LECAKES: So granted. I will mark the affidavit as Exhibit 36.

DIRECT TESTIMONY OF EVAN M. CRAHEN

1 Q. Please state your name and business address.

2 A. My name is Evan M. Crahen and my business
3 address is 6363 Main Street, Williamsville, New York
4 14221.

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

6 A. I am employed by National Fuel Gas Distribution
7 Corporation ("Distribution" or the "Company") as a
8 Regulatory Analyst II in the Rates and Regulatory
9 Affairs Department.

10 Q. Please state briefly your educational and
11 professional experience.

12 A. I graduated from Canisius College in December
13 2006, with a Bachelor of Science degree in Economics
14 and Finance. In January 2007, I began my employment
15 at a Fortune 1000 financial institution as an
16 Accountant/Financial Analyst. In December 2008, I
17 earned a Master of Business Administration degree
18 from Canisius College.

19 In January 2009, I joined Distribution as a
20 Management Associate in the rotational training
21 program. While in the program, I spent three months
22 in the Human Resources Department, a year in the

1 Investor Relations Department, eight months in the
2 Corporate Communications Department, and five months
3 in the Purchasing and Accounts Payable Department.
4 In May 2011, I was promoted to Regulatory Analyst in
5 the Rates and Regulatory Affairs Department, upon
6 the successful completion of the rotational training
7 program. In March 2014, I was promoted to
8 Regulatory Analyst II, my current position.
9 Q. Have you presented expert testimony before any
10 regulatory commissions?
11 A. Yes. I have presented testimony before the
12 Pennsylvania Public Utility Commission pertaining to
13 purchased gas costs.
14 Q. What is the purpose of your direct testimony?
15 A. The purpose of my direct testimony is to describe
16 Distribution's involvement in recently completed and
17 on-going New York regulatory audits. Such activity
18 includes: (1) a recently concluded Comprehensive
19 Management Audit (Case 11-G-0580) conducted by
20 Schumaker & Company ("Schumaker"), (2) a recently
21 concluded Focused Operations Audit of Utilities'
22 Reported Data (Case 13-M-0314) conducted by Overland

1 Consulting ("Overland"), and (3) an in-progress
2 Focused Operations Audit of the Internal Staffing
3 Levels and Use of Contractors for Selected Core
4 Utility Functions at Major New York Energy Utilities
5 (Case 13-M-0449) conducted by The Liberty Consulting
6 Group ("Liberty"). Distribution fully cooperates
7 with consultants and Department of Public Service
8 Staff ("Staff") in an effort to further the goal of
9 producing audit reports that are well-informed,
10 meaningful, and factually correct.
11 Q. Please provide a brief status summary for the
12 Comprehensive Management Audit.
13 A. In January 2012, the Public Service Commission
14 ("Commission") authorized the issuance of a Request
15 for Proposals ("RFP") for an independent third-party
16 consultant to conduct an audit of Distribution's New
17 York gas business pursuant to Section 66(19) of the
18 Public Service Law ("PSL"). In May 2012, the
19 Commission selected Schumaker to conduct the audit
20 under the supervision of Staff. From May 2012
21 through July 2013, Schumaker audited Distribution's
22 New York gas business, focusing on eight elements:

1) Corporate Mission, Objectives, Goals and Planning;
2) Load Forecasting;
3) Supply Procurement;
4) System Planning;
5) Capital and Operations and Maintenance ("O&M") Budgeting;
6) Program and Project Planning and Management;
7) Work Management; and
8) Performance and Results Management.

During audit field work pursuant to the audit process, the Company answered 772 data requests and participated in 120 interviews.

Q. Please describe the results of the Comprehensive Management Audit.

A. In July 2013, Schumaker issued its audit report ("Audit Report") which demonstrates that Distribution is a well-managed, cost-conscious, goal-driven, safety-oriented gas utility that consistently provides excellent service and reliability for its customers. Representative examples supporting this statement were identified

1 by Schumaker in the Audit Report. These include,
2 but are not limited to, the following:
3 • The Internal Audit function has appropriate
4 interaction with the Board of Directors'
5 ("Board") Audit Committee;
6 • The National Fuel Gas Company ("NFG") Board
7 and Board Committees maintain appropriate
8 oversight and controls over NFG companies;
9 • The gas expansion and energy conservation
10 programs are well managed and conform to
11 Commission Orders;
12 • The financial system and processes generally
13 provide adequate capability to trace financial
14 transactions, identify the sources of charges,
15 and document cost assignments and allocations;
16 • The O&M and capital budgeting processes are
17 managed effectively and efficiently, with
18 budget amounts finalized and approved before
19 the start of the fiscal year;
20 • Distribution has comprehensive Distribution
21 Operating Procedures Manual documentation;
22 • The Company has a dynamic operational

procedures and construction standards-setting and review process;

- The Materials Management department has a robust process for managing material inventory levels;
- Distribution uses a modern document management and workflow application for capital project reviews and approvals;
- The Company's Geographic Information System ("GIS") uses a state-of-the-art software platform, including a sophisticated GIS-based leak analysis process;
- The Company uses a "best practice" contractor bidding and management process;
- Supply procurement activities are well managed and Distribution is effectively managing its assets;
- Distribution uses state-of-the-art technology for its workforce management activities; and
- Operational skills training classes for New York employees are completed at a state-of-the-art training center at the Mineral Springs

1 complex.
2 The Audit Report offered 76 recommendations intended
3 to further enhance existing practices and
4 performance within Distribution. The Commission
5 released the Audit Report on August 19, 2013. On
6 September 18, 2013, the Company filed an initial
7 Implementation Plan with the Commission, which
8 accepted, or accepted in part, each of the 76
9 recommendations. This plan also outlined the
10 implementation action steps and milestones
11 Distribution proposed to undertake for each of the
12 76 recommendations. It should be noted that as of
13 its September 18, 2013 filing, Distribution had
14 already begun taking action on 33 of the 76
15 recommendations contained in the Audit Report,
16 demonstrating the Company's commitment to the audit
17 process. Thereafter, the Company and Staff reviewed
18 and discussed the initial Implementation Plan, as
19 well as findings and conclusions made by Schumaker
20 to which Distribution took exception. During these
21 discussions, Staff recommended certain changes and
22 requested further clarification of the Company's

1 proposed action plans. Based on Staff's feedback,
2 Distribution revised its Implementation Plan and
3 subsequently completed two filings with the
4 Commission on January 17, 2014 and April 25, 2014.
5 Q. Did the Commission accept Distribution's
6 Implementation Plan?
7 A. Yes. On June 27, 2014, the Commission issued an
8 Order Approving an Implementation Plan with
9 Modifications ("Order"). In the Order, the
10 Commission approved Distribution's revised
11 Implementation Plan and directed the Company to
12 implement the proposed actions described therein.
13 Q. Is Distribution in compliance with the June 27, 2014
14 Order?
15 A. Yes. Distribution is in full compliance with the
16 requirements outlined in the June 27, 2014 Order.
17 Q. What does the June 27, 2014 Order require with
18 regard to reporting on the status of the
19 Implementation Plan?
20 A. Distribution must file with the Secretary a written
21 update to the Implementation Plan every four months.
22 The update must describe the implementation status

of each recommendation, implementation action steps and major activities undertaken and estimated implementation schedules. In addition, Distribution meets with Staff between each written update to provide additional information and discuss implementation items in further detail. These reporting requirements continue until Staff determines that the Implementation Plan is fully implemented. In addition to the formal reporting requirements, the Company and Staff discuss key initiatives Distribution is undertaking as well as audit coordination and project management items.

Q. What is the current status of the Company's implementation efforts?

A. As of the Company's February 26, 2016 Implementation Plan Update, Distribution reported that:

- 54 recommendations have been completed by Distribution and accepted as closed by Staff;
- 3 recommendations have been completed by Distribution and are pending Staff's review and closure;
- 15 recommendations are in progress; and

1 • 4 recommendations are not yet scheduled to
2 begin.
3 A copy of Distribution's February 26, 2016
4 Implementation Plan Update is provided in
5 Exhibit___(EMC-1). Many of the "in progress"
6 recommendations remain open pending longer-term
7 initiatives within the Company. For example, the
8 implementation of 12 recommendations (serial
9 recommendation numbers 13, 14, 15, 34, 35, 40, 41,
10 46, 53, 55, 56 and 58) are directly related to long-
11 term technology projects or the potential
12 development of new technological applications or
13 systems. Distribution is mindful of the need to
14 implement recommendations in the most efficient and
15 effective manner possible.
16 Q. Did the Comprehensive Management Audit consider
17 implementation costs and savings associated with
18 recommendations being made?
19 A. Yes, in the RFP for the Comprehensive Management
20 Audit, the Commission directed that "whenever
21 possible, recommendations developed by the
22 consultant should be accompanied by cost/benefit

1 analyses which take into account, among other
2 things, one-time and ongoing costs, potential
3 benefits and risks, and potential savings or
4 efficiencies." Accordingly, Schumaker included a
5 Customer Benefit Analysis ("CBA") Appendix in the
6 Audit Report, which provided a CBA for each of the
7 76 recommendations. Although a CBA was prepared for
8 each recommendation, most recommendations do not
9 have quantifiable implementation costs or savings.
10 Q. Are Schumaker's CBA calculations precise?
11 A. No, Schumaker's CBA calculations are not precise.
12 In the Audit Report Schumaker notes that "the CBA
13 process was designed for the consultant to provide a
14 rough estimate of what the costs and benefits might
15 accrue in a dollars representation. It was not
16 intended to be a comprehensive business case for the
17 recommendation but to provide some guidance on
18 expected costs and benefits."
19 Q. Has Distribution performed its own quantification of
20 Audit Report implementation costs and savings?
21 A. Yes, Distribution's quantification of Audit Report
22 implementation costs and savings was filed with the

1 Commission on July 25, 2013. A copy of this
2 analysis, which is included with Distribution's
3 comments on the Audit Report, is provided in
4 Exhibit___(EMC-2). In summary, Distribution's
5 analysis quantifies $19.2 million in implementation
6 costs and $17.0 million in savings, resulting in a
7 net cost of $2.2 million for Distribution during the
8 five year audit window (fiscal 2014 through 2018).
9 When excluding gas costs and gas cost savings from
10 Distribution's analysis, there are $18.7 million in
11 implementation costs and $0.5 million in savings,
12 resulting in a net cost of $18.2 million for
13 Distribution.
14 Q. Are implementation costs associated with the
15 Comprehensive Management Audit reflected in
16 Distribution's revenue requirement?
17 A. Yes, implementation costs associated with the
18 Comprehensive Management Audit are reflected in
19 Distribution's revenue requirement since several
20 recommendations relate to activities the Company has
21 already undertaken, consistent with its commitment
22 to continuous process improvement (e.g., maintaining

1 documented budget and forecast manuals to govern the
2 O&M budgeting, capital budgeting, and financial
3 forecasting processes, as outlined in serial
4 recommendation number 28). To the extent
5 Distribution incurred costs to implement
6 Comprehensive Management Audit recommendations in
7 the twelve month period ended December 31, 2015
8 ("Historic Test Year"), those costs were *de minimis*.
9 Q. Are savings associated with the Comprehensive
10 Management Audit reflected in Distribution's revenue
11 requirement?
12 A. No, this is not necessary. Recommendations with
13 quantifiable savings have already been completed by
14 Distribution and accepted as closed by Staff.
15 Timing-wise, these recommendations were completed
16 before the beginning of the Historic Test Year, and
17 are, accordingly, fully reflected in that
18 information.
19 Q. Please provide a brief status summary for the
20 Focused Operations Audit of Utilities' Reported Data
21 ("Data Audit"), Case 13-M-0314.
22 A. In August 2013, the Commission authorized the

1 issuance of a RFP for an independent third-party
2 consultant to perform a focused operations audit of
3 the accuracy and effectiveness of data used to
4 measure utility performance in: (1) electric
5 service interruption (not applicable to
6 Distribution), (2) gas safety, and (3) customer
7 service. In December 2013, the Commission selected
8 Overland to conduct the audit under the supervision
9 of Staff. From December 2013 through October 2015,
10 Overland audited Distribution's New York gas
11 business. During audit field work, the Company
12 answered 188 multi-part data requests and
13 participated in 27 interviews.
14 Q. Please describe the results of the Data Audit.
15 A. Distribution awaits the formal issuance of the Data
16 Audit Report. In the meantime, the Company remains
17 concerned that there is a lack of uniformity and
18 consistency statewide in the measurement of gas
19 safety and customer service performance metrics.
20 Based on publically available information, the
21 Company believes Overland's Data Audit Report will
22 confirm our belief that each utility is being

1 treated differently by the Commission with respect
2 to calculated performance, and the relationship of
3 that performance to targets with negative revenue
4 adjustments, as established in rate proceedings for
5 each utility. Distribution reserves the right to
6 file supplemental information on this issue when the
7 Overland Data Audit Report is formally released. In
8 addition, I have reviewed publicly available
9 settlement information recently issued by the
10 Commission (e.g., Orange and Rockland - Case 14-G-
11 0494, Central Hudson - Case 14-G-0319, and
12 Consolidated Edison - Case 13-G-0031) and each
13 utility continues to have different performance
14 standards, as well as different measurements of
15 performance, in their respective Joint Proposals.
16 Q. What are the next steps in the Data Audit process?
17 A. As of February 2016, Distribution is currently in
18 the process of reviewing Overland's recommendations
19 in the Data Audit Report. In addition, the Company
20 continues to work with Staff, further discussing the
21 merit and value of the recommendations presented in
22 the Data Audit Report. Distribution anticipates

1 that the Data Audit will be presented at a 2016
2 Commission session and that the Data Audit Report
3 will be made public subsequently.
4 Q. Did the Data Audit consider implementation costs and
5 savings associated with recommendations being made?
6 A. No, Overland did not identify any implementation
7 costs or savings in the Data Audit.
8 Q. Does Distribution agree with Overland's assessment
9 of implementation costs and savings?
10 A. Distribution agrees with Overland that there are no
11 savings to be achieved from the Data Audit.
12 However, the Company notes that the Data Audit will
13 undoubtedly require Distribution to expend resources
14 in order for recommendations to be evaluated and
15 possibly implemented. Beginning with the
16 implementation phase of the audit and extending
17 beyond, to the fullest extent possible, Distribution
18 will continue to refine implementation costs of
19 recommendations. In addition, as the Company
20 evaluates recommendations, viable alternatives that
21 provide more efficient ways of achieving
22 implementation (than Overland originally envisioned)

1 will be presented.

2 Q. Please provide a brief process summary for the

3 Focused Operations Audit of the Internal Staffing

4 Levels and Use of Contractors ("Staffing Audit"),

5 Case 13-M-0449.

6 A. In January 2014, the Commission authorized the

7 issuance of a RFP for an independent third-party

8 consultant to perform a focused operations audit of

9 the internal staffing levels and use of contractors

10 for selected core utility functions at major New

11 York State energy utilities, including Distribution.

12 In June 2014, the Commission selected Liberty to

13 conduct the audit under the supervision of Staff.

14 Liberty began the audit of Distribution's New York

15 gas business in June 2014. As of February 2016,

16 audit field work continues and the Company answered

17 183 multi-part data requests and participated in 12

18 interviews.

19 Q. What are the next steps in the Staffing Audit

20 process?

21 A. Distribution expects Staffing Audit field work to

22 continue, as the engagement is still in progress.

1 In addition, upon conclusion of audit field work,
2 the Company anticipates receiving a draft audit
3 report in order to perform a factual accuracy review
4 as set forth in: (1) the Commission's RFP for this
5 audit, (2) Liberty's work plan, and (3) the multi-
6 party contract executed for the Staffing Audit. In
7 summary, Distribution is confident that the Staffing
8 Audit will confirm the effectiveness of the
9 Company's performance and business practices in
10 resource planning, work management, performance
11 measurement, internal staffing, overtime use, and
12 contractor use.
13 Q. Are there any implementation costs and savings
14 associated with the Staffing Audit?
15 A. Until a final audit report is prepared and presented
16 to the Company, there are no implementation costs or
17 potential savings to be considered from the Staffing
18 Audit.
19 Q. Are you familiar with the Affiliate Rules adopted in
20 Case 04-G-1047?
21 A. Yes, I am familiar with the Affiliate Rules and am
22 compliant with these rules insofar as they govern

1 audit coordination.

2 Q. Does this conclude your direct testimony?

3 A. Yes, at this time.

PUBLIC

REDACTED

VERSION

Q. Please state your name and business address.

A. My name is Evan M. Crahen and my business address is 6363 Main Street, Williamsville, New York 14221.

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

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

Q. Have you testified previously in this rate case proceeding?

A. Yes. I provided direct testimony and exhibits regarding Distribution's involvement in recently completed and on-going New York regulatory audits. In addition, I provided direct testimony, exhibits and workpapers as part of the Cost of Service and Rate Design Panel, the Energy Services Panel, and the Working Performance Metric Panel.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to provide the Company's rebuttal position on recently completed and on-going New York regulatory audits. Such activity includes: (1) a recently concluded

Comprehensive Management Audit (Case 11-G-0580) conducted by Schumaker & Company ("Schumaker"), (2) a recently concluded Focused Operations Audit of Utilities' Reported Data (Case 13-M-0314) conducted by Overland Consulting ("Overland"), and (3) an in-progress Focused Operations Audit of the Internal Staffing Levels and Use of Contractors for Selected Core Utility Functions at Major New York Energy Utilities (Case 13-M-0449) conducted by The Liberty Consulting Group ("Liberty"). This testimony will also provide the Company's rebuttal position on productivity, from a New York regulatory audit perspective.

Q. Please describe Staff's position on Distribution's compliance with management audit requirements.

A. The direct testimony of Mr. Lavery, at 7, describes how Distribution has filed timely implementation updates and has met with Department of Public Service Staff ("Staff") in conjunction with written updates in accordance with the New York State Public Service Commission's ("Commission") Order Approving an Implementation Plan With Modifications, issued

and effective June 27, 2014, in Case 11-G-0580 ("June 27, 2014 Order").

Q. Does Distribution agree with Staff's position, as respects compliance with the June 27, 2014 Order?

A. Yes. Distribution is in full compliance with the requirements of the Commission's June 27, 2014 Order.

Q. What is the current status of the Company's management audit implementation efforts?

A. As of the Company's June 24, 2016 Implementation Plan Update, which was filed in Case 11-G-0580, Distribution reported that:

- 56 recommendations have been completed by the Company and are accepted as closed by Staff;
- 1 recommendation has been completed by the Company and is pending Staff's review and closure;
- 15 recommendations are in progress; and
- 4 recommendations are not yet scheduled to begin.

Q. Is Distribution's position consistent with Staff's position, as respects implementation costs or

benefits (resulting from the implementation of management audit recommendations) included in the rate year?

A. Yes. Distribution's position is consistent with Staff's position. The direct testimony of Mr. Lavery, at 9, confirms there are no recommendations with implementation costs or benefits that will be implemented during the rate year.

Q. Did Staff recommend any adjustments to the Company's rate year forecast for management audit expense?

A. Yes. The direct testimony of Mr. Lavery, at 10, notes "the Department's Management Audit Unit does not anticipate that a management audit will be conducted of Distribution during the rate year, and as such, the associated costs should be removed."

Q. Does Distribution agree with Staff's recommendation?

A. No. During discovery, Distribution asked Staff to provide a detailed schedule of each management audit and statewide operational audit anticipated for calendar years 2017 through 2021, a five year forecast of anticipated audits. A copy of Staff's response to the data request is provided as

Exhibit___(EMC-6). In the data request response, Staff stated "The Commission has not established a schedule of future management and/or statewide operational audits." Since a future schedule has not been established by the Commission, there is no evidence to substantiate Mr. Lavery's claim that a management audit of Distribution will not occur during the rate year.

Q. When did the Schumaker management audit begin?

A. The Commission selected Schumaker on May 17, 2012, and field work instantly commenced.

Q. According to Public Service Law §66(19a), what is the frequency of a management audit?

A. My counsel advises me that §66(19a) states "The Commission shall have power to provide for management and operations audits of gas corporations and electric corporations. Such audits shall be performed at least once every **five years** [emphasis added] for combination gas and electric corporations, as well as for straight gas corporations having annual gross revenues in excess of two hundred million dollars."

Q. When is five years from May 17, 2012?

A. Five years from May 17, 2012 is May 17, 2017.

Q. Is May 17, 2017 in the rate year for this proceeding?

A. Yes. The rate year is the twelve months ended March 31, 2018. May 17, 2017 would occur during the rate year.

Q. Where in Distribution's rebuttal testimony will audit costs be addressed?

A. Ms. Friedrich-Alf's rebuttal testimony will address audit costs.

Q. Please describe the remainder of Mr. Lavery's direct testimony.

A. Pages 11 and 12 of Mr. Lavery's direct testimony describe Distribution's participation in statewide operational audits (Cases 13-M-0314 and 13-M-0449).

Q. Please describe the first multi-utility operational audit outlined in Mr. Lavery's testimony.

A. The first multi-utility operational audit is Case 13-M-0314, the Review of the Accuracy and Effectiveness of Certain Reliability and Customer Service Systems at all Gas and Combination Gas and

Electric Utilities in New York State that Provide Statistics to the Commission on the Services They Provide Customers. In accordance with ordering clause 1 of the Commission's Order Releasing Report and Providing Guidance on Response, issued and effective April 20, 2016 ("April 20, 2016 Order"), the final audit report was made public.

Q. What is the current status of Case 13-M-0314, since the final audit report was made public?

A. Ordering clause 2 of the April 20, 2016 Order required Distribution to file an Implementation Plan in Case 13-M-0314 within 30 days. As a result, the Company filed its Implementation Plan in Case-13-M-0314 on May 20, 2016. Also on May 20, 2016, the Company filed a letter, noting several legal concerns and stating that Distribution fully reserved any and all of its legal rights, and waived no such rights through its continued participation in the audit proceeding.

On June 22, 2016, the Department of State's Division of Administrative Rules published Volume XXXVIII, Issue 25 of the New York State Register

("June 22, 2016 Register"). Included in the June 22, 2016 Register, at I.D. No. PSC-25-16-00015-P et. al. (for the series of applicable notices pertaining to all major New York State gas and electric utilities included in the scope of the operational audit), was a notice of proposed rulemaking noting the Commission is considering Audit Implementation Plans submitted by the utilities and whether to order the implementation of audit recommendations, with comments due by August 8, 2016.

On August 4, 2016, Distribution filed a Request for Additional Time to Comment and Petition for Clarification, requesting: (1) that the Commission revisit its procedures to permit utilities to address and contest audit recommendations in a public forum with formal resolution of the contested recommendations; (2) to re-open the April 20, 2016 Order in Case 13-M-0314 to permit Distribution the opportunity to disagree with any of the audit recommendations based on sufficient cause shown and to have the recommendations resolved in a public process through notice and comment, or more formal

hearings if warranted; (3) to permit the Company to submit a revised implementation plan, following the aforementioned process; (4) to review and revise the process by which guidance documents are issued, particularly with respect to gas safety reporting and customer service standards not otherwise addressed in regulations, and if warranted, formally institute rulemaking proceedings for the adoption of mandatory gas safety reporting and/or customer service standards should it wish to apply those standards on a mandatory basis to all utilities in the state; and (5) to extend the State Administrative Procedure Act ("SAPA") comment deadline of August 8, 2016.

On August 15, 2016, the Commission issued a Notice Soliciting Comments ("August 15, 2016 Notice"), which established a September 16, 2016 deadline to supplement comments pursuant to the aforementioned June 22, 2016 Register publication. The Company's comments are expected to be filed in a timely manner.

Q. Does Mr. Lavery's testimony note anything additional

about Case 13-M-0314?

A. Yes. Mr. Lavery's testimony, at 11 and 12, notes that the "implementation plans filed by Distribution and the other utilities are currently under review and will be presented to the Commission for its consideration in the coming months." Given the Commission's August 15, 2016 Notice and the statements contained therein which invite comments expressing disagreement with the audit recommendations made by Overland, the implementation plans submitted in compliance with the April 20, 2016 Order may change.

Q. Does Mr. Lavery's statement relate to other direct testimony in this rate proceeding?

A. Yes, Mr. Lavery's testimony relates to Staff's Gas Safety Panel. This panel mentions Case 13-M-0314 in their direct testimony, at 56 and 57.

Q. Please describe the Gas Safety Panel's position.

A. The Gas Safety Panel makes a recommendation for an annual reporting requirement on gas safety measures. The Gas Safety Panel notes that modifications to data, as identified in Case 13-M-0314, "should be

required to be incorporated" into the annual reporting requirement.

Q. Does Distribution agree with the Gas Safety Panel's recommendation, as respects Case 13-M-0314?

A. No, this recommendation should be rejected by the Commission. The Gas Safety Panel's recommendation is inconsistent with Mr. Lavery's quotation noted above. The Company is unaware, procedurally, how data modifications can be ordered upon utilities before a formal notice and comment process is facilitated, as mandated by the New York State Constitution and SAPA, both of which, I am advised by counsel, must be followed when agencies engage in statewide rulemaking. This is yet another example of how an audit should not be used as a substitute for a proper notice and comment process. In addition, this example illustratively points out why the use of guidance documents to prescribe the conduct of utilities is inappropriate and not a valid substitute for notice and comment regulation, followed by appropriate codification of such regulations within the New York Code of Rules and

Regulations ("NYCRR"). Both of these concepts will be further described in detail in Distribution's comments, which will be filed in response to the August 15, 2016 Notice, in Case 13-M-0314.

Q. Is Distribution's position consistent with Staff's position, as respects implementation costs or benefits (resulting from the implementation of operational audit recommendations in Case 13-M-0314) included in the rate year?

A. Yes. Distribution's position is consistent with Staff's position. The direct testimony of Mr. Lavery, at 11 and 12, confirms there are no recommendations with implementation costs or benefits that will be implemented during the rate year.

Q. Please describe the other multi-utility operational audit outlined in Mr. Lavery's testimony.

A. The other multi-utility operational audit is Case 13-M-0449, the Focused Operations Audit of the Internal Staffing Levels and the Use of Contractors for Selected Core Utility Functions at Major New York Energy Utilities. Mr. Lavery's testimony, at

12, notes "this audit is nearing completion and the final report is expected to be released later in 2016."

[Begin Confidential]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[End Confidential]

Q. Did Staff's testimony identify implementation costs, resulting from the implementation of operational audit recommendations in Case 13-M-0449?

A. No. The direct testimony of Mr. Lavery, at 12, did not identify implementation costs resulting from the

implementation of operational audit recommendations in Case 13-M-0449.

[Begin Confidential]

[redacted]

[End Confidential]

Q. Please describe Staff's productivity adjustment

proposal.

A. Mr. Haslinger's testimony, at 16 through 18, describes Staff's recommended 2% productivity adjustment. Mr. Haslinger notes that a productivity adjustment is intended to "capture unidentified and/or unquantifiable productivity gains, efficiencies and cost savings that could be realized in the rate year."

[Begin Confidential]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[End Confidential]

In the end, Staff applied a "rule of thumb penalty" on Distribution, by recommending a 2% productivity adjustment. In other words, Staff's adjustment is simply a blanket disallowance, devoid of reliance on any specific productivity or efficiency study. It is more akin to a penalty and based on nothing more than "Commission policy." Staff provides no numerical or analytic studies to justify or support the alleged 2% productivity adjustment. Mr. Haslinger's testimony confirms that the "rule of thumb penalty" is unquantifiable and is not supported by analysis whatsoever. Given this

statement, Staff has not presented any evidence in this proceeding justifying that a rule of thumb penalty be applied to Distribution.

Interesting enough, during discovery in this proceeding, in response to a Distribution data request, Staff stated that "Staff does not measure productivity performance of individual utilities." A copy of Staff's data request response, which affirms this fact five times, is provided as Exhibit___(EMC-5). Given that Staff has admitted that it does not measure productivity performance, there is no legitimate basis for Staff to recommend a productivity adjustment for Distribution.

[Begin Confidential]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[End Confidential]

Finally, it should be noted that although the Staff Gas Policy & Supply Panel, at 35 through 38, cites numerous types of "benefits" associated with workforce development programs, no numerical

analyses, analytic studies, or exhibits were submitted as evidence to substantiate the alleged claim of benefits and cost savings. In fact, during discovery the Company submitted four data request questions, inquiring about Staff's alleged claim of benefits and cost savings. Copies of the responses received from Staff are provided as Exhibit___(EMC-7). This Exhibit not only invalidates Staff's testimony, but confirms there are no benefits or cost savings from Staff's workforce development recommendations.

Q. Does this conclude your rebuttal testimony?

A. Yes, at this time.

A.L.J. LECAKES: Thank you. And Mr. Crahen's exhibits?

MR. NICKSON: Attached to the direct testimony of Mr. Crahen are two exhibits which were identified as EMC-1 and EMC-2 and attached to the rebuttal testimony of Mr. Crahen are five exhibits identified as EMC-3 through EMC-7 and I would ask that each of these be marked for identification.

A.L.J. LECAKES: Those are attached to his direct and his rebuttal or --?

MR. NICKSON: I have two exhibits attached to his direct I believe and five exhibits attached to his rebuttal.

A.L.J. LECAKES: Okay. I don't find them on the list here.

MR. NICKSON: Your Honor, the -- the way that we had submitted the list, it may -- it may be a little confusing, but we did all of the direct exhibits first followed by all of the rebuttal and so --.

A.L.J. LECAKES: Right. And I'm looking at the direct and not finding --.

MR. NICKSON: At the bottom of page 5, the last two?

A.L.J. LECAKES: There they are.

Okay.

MR. NICKSON: Okay.

A.L.J. LECAKES: So we're at 37 and 38 for those --

MR. FAVREAU: And that's the direct?

A.L.J. LECAKES: That's the exhibits that were attached to the direct so that would be 37 would be EMC-1 and 38 would be EMC-2 and then turning to page -- I'm losing Evan's exhibits.

MR. NICKSON: Page 15, Your Honor.

A.L.J. LECAKES: Here they are. Okay. And that would be numbers 39 for EMC3 -- 39P for EMC3, 39C for EMC3 confidential, 40P for EMC4 of the public version redacted, 40C for EMC4 the confidential version, and 41 for EMC5, 42 for EMC6 and 43 for EMC7. Okay. So we're up to 43. Next affidavit?

MR. NICKSON: The next affidavit is for company witness Kathleen A. Frank. Ms. Frank prepared testimony entitled The Direct Testimony of Kathleen A. Frank which consists of 4 pages of questions and answers. Ms. Frank also prepared testimony entitled The Rebuttal Testimony of Kathleen A. Frank which consists of 10 pages of questions and answers. I ask that the direct and rebuttal testimony of Kathleen A. Frank be incorporated

into the record as if given orally today.

A.L.J.LECAKES: That's granted.

We will mark the affidavit as Exhibit 44.

Direct Testimony of Kathleen A. Frank

1 Q. Please state your name and business address.

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

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

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

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

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

16 Q. What is the purpose of your testimony?

17 A. I will be describing the methodology that was utilized to forecast the uncollectible
18 accounts expense.

1 Q. What do you expect the total uncollectible expense to be for the 12 months ending
2 March 31, 2018?

3 A. I project the total uncollectible accounts expense for the 12 months ending March
4 31, 2018 to be $8,748,000.

5 Q. How was the uncollectible accounts expense of $8,748,000 determined?

6 A. The uncollectible accounts expense for the twelve months ending March 31, 2018
7 was determined by first calculating the 3 year average of the normalized historical
8 fiscal years' (fiscal years: 2013, 2014 & 2015) net write-off as a percent of the prior
9 fiscal years' (fiscal years: 2012, 2013 & 2014) retail and transportation revenues
10 ("factor"). This historical 3 year average factor was then multiplied by the
11 projected 2018 retail and transportation revenues to derive the projected
12 uncollectible accounts expense for the twelve months ending March 31, 2018.
13 Please refer to Exhibit_(KAF-1), Schedule 1, Sheet 2 of 2 which details these
14 calculations.

15 Q. Please define the term net write-offs?

16 A. Net write-offs reflect the gross write-offs less sales tax less other recoverable taxes
17 and recoveries.

1 Q. Why did you utilizethe 3 year average of the prior fiscal years' retail and
2 transportation revenue but the 3 year average of the current fiscal years'
3 normalized historical net write-off when calculating the factor?

4 A. Write-offs are typically written off 12 months after the original due date of the final
5 bill. Therefore, this lag is appropriate since it attempts to mirror the actual timing
6 of the current process.

7 Q. When calculating the factor, why do you utilize 3 years of revenues as well as 3
8 years of net write-offs?

9 A. It is appropriate to use this approach because the utilization of 3 years of data
10 smoothes or averages out any unusual occurrences that might be present if just 1
11 year of data was utilized.

12 Q. Why do you feel that this methodology provides the most accurate projection of
13 uncollectible accounts expense?

14 A. This method is based upon a normalized historical actual factor being applied to
15 the forecasted revenues that are utilized for the rate year, i.e., the twelve months
16 ending March 31, 2018. This is why, in my opinion, this method provides the most
17 accurate projection.

18 Q. Does your department transact business with energy service companies ("ESCOs")
19 in New York?

Case 16-G-0257 Rebuttal Testimony of Kathleen A. Frank

Q. Please state your name and business address.

A. My name is Kathleen A. Frank. My business address is 6363 Main Street, Williamsville, New York 14221-5887.

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

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

Q. Have you testified previously in this case?

A. Yes. I provided Direct Testimony, Exhibits and workpapers regarding the Company's uncollectible accounts expense.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to address Mr. Davi's testimony and exhibits regarding uncollectible accounts expense, to provide clarifying information regarding the normalizing adjustment included in my original testimony and exhibit, to present clarifying rebuttal testimony and an exhibit that removes all of the effects of bad debt transfers, to address and include in the exhibit the loss of funding for the LICAAP arrearage forgiveness program proposed by the Customer Service Low Income panel and to address Staff

Consumer Services Panel testimony from Ms. Ferreri regarding an incentive proposal for residential service terminations and uncollectibles.

Normalizing Adjustment for Bad Debt Transfers

Q. Do you agree with Mr. Davi's statement that the normalizing adjustment arbitrarily increases the Company's FY 2015 net write-off factor?

A. No. The normalizing adjustment of $5.983 million is not an arbitrary figure designed to increase the FY 2015 net write-off factor.

Q. How do you define a bad debt transfer in the legacy customer billing system?

A. A bad debt transfer was the prior balance/amount owed by a customer that was previously written-off. In our legacy customer billing system, when a customer with a prior balance owed to the Company which had been written-off applied for new service with our Company, this bad debt transfer amount would be reflected in the current balance owed to our Company. In order to transfer this balance to the customer's new account, an accounting entry to the customer's account was required. The accounting entry was a

recovery to the bad debt reserve and an increase to accounts receivable.

Q. Why did you transfer balances back to customers who applied for new service with the Company?

A. Our Company believes that a customer should remain responsible for balances that they incurred and we encourage our customers to be responsible and pay, to the best of their ability, for these services.

Q. How will bad debt transfers be recognized in the new customer billing system?

A. The enhanced functionality of the new customer billing system which was implemented in May of 2016 provides the ability to mark open items (prior written-off balances) as doubtful entries. Prior debt balances owed will stay doubtful/written-off in the new system but still continue to be linked with the customer's account. Accordingly, no accounting entry will need to be made in the new system for the prior bad debt balance owed.

Q. Why is it necessary to include the normalization entry in your original model?

A. The model in my original testimony and exhibits includes all bad debt

transfer entries. The normalizing entry is necessary in the model because the historical period (FY 2013-2015) contains bad debt transfer amounts (recoveries) still in the financial statements (bad debt reserve and accounts receivable) as of the end of fiscal year 2015 that need to be reversed (i.e., re-written-off). Since the new system will no longer require a bad debt transfer recovery entry, the normalizing entry is necessary to reverse the impact upon the financial statements (bad debt reserve and accounts receivable) of legacy bad debt transfer recoveries. This normalizing entry is to write-off again, and classify as doubtful, the accounts with prior bad debt balances. All of the bad debt transfer entries, the recoveries and re-writing off, need to be included in order to properly account for the change in the process of accounting for the prior bad debt balances that remain unpaid.

Q. Has the normalizing entry reflected in your direct testimony and exhibits been booked now that the new customer billing system has been implemented?

A. Yes, there were 3 normalizing entries that were booked in July and August 2016 totaling $5,992,747.30 of gross write-offs less sales tax.

The gross receipts tax for these entries is estimated to be $189,249.05. The net normalizing amount is $5,803,498.25 ($5,992,747.30 less estimated gross receipt taxes of $189,249.05).

Q. How does the normalizing entry in your testimony, exhibits and interrogatory responses compare to the amounts actually booked?

A. The estimated normalizing entry reflected in my testimony, exhibits and interrogatory responses was $5,983,000. The actual normalizing entries total $5,803,498.25 which is $179,501.75 lower than my initial estimate.

Q. Should the difference of $179,501.75 be deducted from the normalizing entry utilized for FY2015.

A. Yes, this amount should be deducted and the FY2015 factor should be recalculated to reflect this difference.

Q. Why are there multiple entries rather than just one entry being booked for the normalization adjustment?

A. The large number of accounts and their complex nature required the entry to be processed in multiple stages. At this time, we do not anticipate any further normalizing entries other than as mentioned above, as this is a limited occurrence associated with the Company's

transition to the new system.

Q. Do you agree with Mr. Davi's removal of the normalizing adjustment from FY2015 and the recalculation of FY2015 factor?

A. No. Mr. Davi's removal of the normalizing adjustment from FY2015 and recalculation of the factor for FY2015 excludes the impact of the bad debt transfer net recoveries net of those amounts re-written-off that were booked in FY2013, FY2014 and FY2015.

Q. Do you agree that only the FY2015 factor should be recalculated due to Mr. Davi's removal of the normalization adjustment?

A. No. If the normalization adjustment is removed from the FY2015 period, the recoveries of the amounts previously written off which remain unpaid and transferred to active status must also be removed from not only FY2015 but also from FY2013 and FY2014 and all three years factors should be recalculated accordingly.

Q. Do you agree with Mr. Davi's use of the three year average factor which takes into account FY 2013, 2014 and 2015?

A. Yes I do, as long as they are adjusted as previously stated in my rebuttal testimony.

Q. Are you submitting a new exhibit which removes all the effects of the

bad debt transfers from FY 2013, 2014 and 2015?

A. Yes. Exhibit KAF-2 provides an exhibit which removes all the effects of the bad debt transfers from FY 2013, 2014 and 2015.

Q. How is Exhibit KAF-2 different from KAF-1?

A. As previously stated in this rebuttal testimony it removes the normalization adjustment from FY 2015 and eliminates the effects of bad debt transfer on the factors which have been recalculated for the three years of FY 2013, 2014 and 2015.

Q. Are there any other changes to the Exhibit KAF-1 that are reflected in KAF-2?

A. Yes. Exhibit KAF-2 includes an additional line item, #21, for the inclusion of the $2,480,846 LICAAP arrearage forgiveness program which was eliminated by the Customer Service Low Income Panel.

LICAAP Arrearage Forgiveness Program

Q. Why did you include the LICAAP arrearage forgiveness amount to the uncollectibles expense?

A. At this time, the LICAAP arrearage forgiveness program is handled as a separate program with its own funding source. If the arrearage forgiveness amounts are reduced or eliminated, those accounts will

need to be handled through normal write-off procedures. Since the LICAAP program customers will not have their arrearages forgiven and the default rate of the LICAAP customers to pay their balances will not change, these arrearages will need to be written-off, increasing the uncollectible accounts expense accordingly.

Residential Service Termination "Incentive"

Q. Do you agree with the Consumer Services Panel's proposal regarding an incentive program related to residential service terminations and uncollectibles expense?

A. No. I believe that it is inappropriate to attach an incentive program to residential service terminations and uncollectibles.

Q. Why do you believe that it is inappropriate to attach an incentive program to residential service terminations and uncollectibles?

A. Our Company does not take the termination of a residential customer's service lightly and offers a significant number of payment options to try to avoid the termination of a customer's residential service. Budget billing, deferred payment agreements, as well as educating our customers regarding the number of assistance programs available are just a few examples. The Company is very

conscious of the hardship a customer incurs as a result of their service being terminated and great effort is expended to keep a customer in service. This is just one more factor contributing to the level of our residential service terminations and uncollectibles. Even after a customer is terminated, we have a robust collection effort in place to try to recover dollars and keep our uncollectible expense as low as possible. The Company is not trying to make money on uncollectible expenses, rather it is merely trying to be made whole for those customers who cannot or will not pay for the services that have been provided and keep such expenses as low as possible for the rest of our customers. In order for an incentive to be effective in achieving the desired goal of the Company's efforts it must be able to provide a meaningful difference toward achieving the stated goal. Uncollectible balances are more a function of the market price of gas than the Company's termination efforts. As the marked price of gas increases the experienced level of uncollectible expense will increase. Similarly service terminations will be influenced more by changing macro economic conditions and changing levels of low income assistance programs relative to gas price changes than by

any speculative and unidentified improvements in collection practices of a utility.

In addition to my aforementioned reasons for not agreeing with the proposed incentive structure I would like to also disagree with the numbers proposed in Exhibit CSP-6 because there are many items related to terminations and uncollectibles which are out of the Company's control. A few examples of these are the amount of Home Energy Assistance Program,(HEAP), that will be available for and received by our customers in any given year and the number of heating degree days in any particular heating season which is completely weather dependent. Please refer to the Company's Customer Service Panel for further information regarding these topics.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, at this time.

1 A. Yes. We perform credit checks on ESCOs who serve customers on Distribution's
2 New York system. We evaluate creditworthiness according to the standards and
3 procedures contained in Distribution's tariff and the Uniform Business Practices
4 established by the New York State Public Service Commission in Case 98-M-1343.

5 Q. Does your department comply with Distribution's rules governing transactions with
6 affiliates?

7 A. Yes. Each employee in my department, including myself, is required to sign a
8 statement indicating that we understand and observe the affiliate rules.
9 Furthermore, we work closely with counsel who advises us on affiliate rules
10 compliance issues. We are very sensitive to these issues and have developed a
11 culture of compliance with affiliate rules in all of our business transactions.

12 Q. Does this conclude your testimony?

13 A. Yes, at this time.

A.L.J. LECAKES: I want to turn back to Evan Crahen for a second and direct the court reporter that the testimony included in there did have confidential information in it. Today's record should have two transcripts made: One that is redacted with publicly available information and one that has the confidential information in it. For Mr. Crahen's direct testimony, that appears as Crahen Direct and that will just be the one testimony there. That did not have any confidential information in it. In the Crahen Rebuttal Testimony, there will be a Crahen Rebuttal Testimony Public Redacted version that can be in the public transcript. The Crahen Rebuttal Testimony that has confidential attached to it, that should be the only one that appears in the confidential record in place of the Crahen Rebuttal Public Redacted version.

All right. So getting back to witness Frank.

MR. NICKSON: Attached to the direct testimony of Ms. Frank is one exhibit KAF-1 and attached to the rebuttal testimony of Ms. Frank is also one exhibit identified as KAF2. I would ask that each of these documents be marked for identification.

A.L.J. LECAKES: So the Frank

affidavit is marked as Exhibit 44 and for the record that should have Frank Direct Testimony and Frank Rebuttal Testimony. Those files copied into the record as if orally given. The Frank KAF1 is Exhibit 45 and was there an additional exhibit there?

MR. NICKSON: Yes.

A.L.J. LECAKES: Yes. KAF2 should be 46. Next witness?

MR. NICKSON: The next witness is Lee E. Hartz. Mr. Hartz prepared a testimony entitled The Supplemental Direct Testimony of Lee E. Hartz which consists of 9 pages of questions and answers. I ask that the supplemental direct testimony of Lee E. Hartz be incorporated into the record as if given orally today.

A.L.J. LECAKES: So granted. The affidavit will be marked 47. On the disk from the company there is a folder called Company Supplemental Testimony -- no. Where does this appear on the disk, Mr. Nickson?

MR. NICKSON: There should be -- there -- I think there's two folders on that disk.

A.L.J. LECAKES: 6/10/2016 Company Supplemental Testimony.

MR. NICKSON: Correct.

A.L.J. LECAKES: And it will be Hartz Supplemental Direct Testimony should be copied into the record at this point. So that's the June 10, 2016 folder Company Supplemental Testimony.

SUPPLEMENTAL DIRECT TESTIMONY OF LEE E. HARTZ
REGARDING SITE INVESTIGATION AND REMEDIATION ("SIR")

I. <u>Introduction</u>

Q. Please state your name and business address.

A. My name is Lee E. Hartz. My business address is 6363 Main Street, Williamsville, New York 14221-5887.

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

A. I am employed by National Fuel Gas Supply Corporation as Assistant Vice President, Land and Risk Management. I am submitting this testimony on behalf of National Fuel Gas Distribution Corporation ("Distribution" or "the Company"). Distribution is an affiliate of National Fuel Gas Supply Corporation.

Q. Please describe your educational background.

A. I hold BA degrees in History and Communication Arts from Allegheny College, Meadville PA, (1998) and a JD degree from Hamline University School of Law, St. Paul, MN (2001).

Q. Please describe your experience.

A. I began my career as an associate at KL Gates, Pittsburgh, PA from 2001 to 2004. I accepted a position in 2004 with Distribution as an Attorney in Erie, PA. In 2008, I became a Senior Attorney and Manager of Land and Real Estate at Distribution's offices in Erie, PA. In 2009, I was promoted to Assistant General Counsel and Assistant General Manager – Land, in the Erie office. I relocated in 2010 to the Williamsville, NY office where I

became General Manager, Land & Risk Management. In 2013, I assumed my current position as Assistant Vice President, Land and Risk Management with Supply Corporation. In that position, my responsibilities include: general oversight of the Land Department and Risk Management Department of National Fuel Gas Company's regulated companies. Specific to this testimony, my responsibilities include the general oversight of Distribution's site investigation and remediation programs.

Q. Have you previously testified before the New York State Public Service Commission?

A. No, I have not.

Q. Have you testified before any other Commission?

A. Yes, I have testified before the Pennsylvania Public Utility Commission.

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

A. The purpose of this supplemental direct testimony is to: (1) demonstrate that Distribution's remediation process is in compliance with existing timetables and New York State Department of Environmental Conservation ("DEC") requirements; (2) explain Distribution's SIR cost control efforts and demonstrate the Company's compliance with the best practices inventory developed in Case 11-G-0034; and (3) explain the internal process the Company follows with respect to reviewing SIR procedures, and how

Distribution's internal controls are brought to bear on site investigation and remediation projects.

Q. Are you sponsoring any exhibits to accompany your testimony?

A. Yes, I am sponsoring the following exhibits: Exhibit ___ (LEH-1) is a copy of Distribution's 2015 Annual SIR Report entitled "Annual Report Concerning The Status Of Site Investigation And Remediation Costs, Schedules And Regulatory Compliance" which was submitted to the Secretary of the Commission on March 31, 2016; Exhibit ___ (LEH-2) is a copy of Distribution's 2014 Annual SIR Report that was submitted on March 31, 2015; Exhibit ___ (LEH-3) is a copy of Distribution's 2013 Annual SIR Report that was submitted on March 31, 2014; and Exhibit ___ (LEH-4) is a copy of Distribution's 2012 Annual SIR Report that was submitted on July 10, 2013.

Q. Are you familiar with the Order issued on November 28, 2012 in Case 11-G-0034, the generic SIR proceeding?

A. Yes, I am.

Q. Does your testimony address the matters addressed in that order?

A. Yes, although those same issues were addressed in the annual reports which I have included as exhibits and which were referenced in the Direct Testimony of Ms. Friedrich-Alf regarding the Rate Year effects of the Company's SIR activities. Nothing material has changed with respect to the

Company's SIR sites since the filing of the last report.

II. Compliance With Existing Timetables And DEC Requirements

Q. Please provide an overview of the number of sites adhering to the anticipated schedule, the number of sites ahead of schedule and the number of sites experiencing schedule slippage.

A. The Company's 2015 SIR report (Exhibit ___ (LEH-1)) shows that all schedules have continued without undue delays by the Company. The chart reproduced below shows the status of all sites:

SUPPLEMENTAL DIRECT TESTIMONY OF LEE E. HARTZ
REGARDING SITE INVESTIGATION AND REMEDIATION ("SIR")

Site Name	Schedule
Bradley/Westwood	Remediated - monitoring.
Buffalo Service Center	No scheduled action by the Company.
Former Buffalo Service Center Station- Offsite	Final Site Characterization approved by DEC on 3/20/14. Remedial project to be closed pending survey, site management plan and environmental notice.
Mineral Springs Works	Remediated - monitoring.
Tonawanda MGP	Remediation completed. Demobilization occurred in February 2016. Post-remediation sampling and O&M pending survey, final engineering report, site management plan and environmental easement.
Dunkirk MGP	Remedial Investigation completed. Feasibility Study to begin pending DEC review and comment on data.
Hornell-MGP	Feasibility Study and suggested remedy submitted to NYSDEC for comment.
Eight Sites Identified by DEC	Researching Liability/Preliminary.
York Oil (PRP)*	No Further Company Action, closure pending DEC approval.
Regulator Stations	No Further Company Action as regulator stations are retired and investigated.

Q. Please describe any changes in the anticipated schedule of the Company's SIR program and provide an explanation for any scheduling delays resulting from non-site specific causes.

A. There have been no changes in the anticipated schedules from non- site specific causes.

Q. Please indicate any sites that are not in compliance and provide an

explanation for the non-compliance.

A. All sites are in compliance.

III. <u>Best Practices</u>

Q. Are you familiar with the list of best practices developed in Case 11-M-0034?

A. Yes. The Commission's November 28, 2012 Order ("SIR Order") in that proceeding, at page 30, stated that:

> The compilation of an inventory of least-cost practices and cost-effective remediation methods was offered by the utilities, which routinely share and coordinate this information amongst themselves, with DEC, and with other companies and organizations experienced in SIR. The ALJ recommended the compilation of an inventory of least-cost practices and cost-effective remediation methods to provide a valuable checklist for future rate case review of SIR expenses. No party excepted. We adopt this recommendation and require the utilities to formalize their best-practices compilation concerning cost-control measures and cost-effective remediation techniques. We will require a joint utilities' filing of such a compilation to serve as a benchmark for evaluation of future SIR activity.

SUPPLEMENTAL DIRECT TESTIMONY OF LEE E. HARTZ REGARDING SITE INVESTIGATION AND REMEDIATION ("SIR")

On March 28, 2013, the utilities that had participated in Case 11-M-0034 filed a list of best practices with the Secretary. On April 11, 2013, the DEC noted that remediated brownfield sites would still need to comply with DEC regulations but did not otherwise take issue with the best practices list.

Q. Is Distribution in compliance with those best practices?

A. Yes. I hereby attest that Distribution is in compliance with the best practices inventory.

Q. Please discuss Distribution's SIR cost control efforts.

A. The Company is extremely proactive in ensuring that robust SIR cost control practices are in place. Rigorous cost control is practiced throughout all aspects of the Company's operations, including the SIR program. Specific to SIR projects: (1) the Company staffs its SIR program with experienced environmental professionals who closely monitor projects, review plans and specifications and review all contractor invoices; (2) the Company utilizes specialized outside environmental consultants with significant experience in similar projects; (3) as discussed below, Distribution's Procurement Manual for procurement of goods and services is utilized for all SIR projects. This manual includes detailed descriptions of Distribution's competitive procurement process, its contracting standards and vendor qualification; (4) Company personnel involved with the SIR process keep up to date on industry developments that may afford further opportunity for enhanced cost

savings, and evaluate and implement alternatives where feasible; and (5) for each SIR project vendor, invoices are subject to strenuous review including monthly authorization and budget tracking, detailed backup information and break-out requirements, progress reporting to ensure each task remains on budget and enhanced change order requirements when costs exceed estimates.

IV. <u>Distribution's Internal Controls</u>

Q. Please address the results of any internal process Distribution has conducted with respect to a review of SIR procedures with particular emphasis on how internal controls are brought to bear on site investigation and remediation projects.

A. Distribution's SIR projects are not exempt from the Company's standard internal controls and are subject to the same rigorous internal controls as any other projects or spending at the Company. SIR projects are subject to all provisions of Distribution's Procurement Manual, which was attached as part of Exhibit ___ (LEH-1). In fact, Distribution's SIR projects are subject to additional controls in that, at least quarterly; but usually more frequently, the Company holds formal internal meetings with the specific purpose of reviewing activity, progress, spending and status of investigation and/or remediation of each of the sites previously identified. These meetings are attended by myself and Distribution's Manager of Environmental Services,

members of Distribution's upper management, and members of Distribution's Accounting Services Department. Further, all invoices related to SIR projects receive increased scrutiny by both myself and Distribution's Manager of Environmental Services with backup documentation required for all expenditures.

Q Does this conclude your testimony?

A. Yes, at this time.

A.L.J. LECAKES: Were there any exhibits attached to that?

MR. NICKSON: There were. Attached to the supplemental direct testimony of Mr. Hartz are four exhibits LEH1 through LEH4 and I would ask that each of those documents be marked for identification.

A.L.J. LECAKES: They will so be marked as 48, 49, 50, and 51. The next witness?

MR. NICKSON: The next witness, Your Honor, is company witness Donald N. Koch, K-O-C-H. Mr. Koch prepared testimony entitled The Direct Testimony of Donald N. Koch which consists of seven pages of questions and answers and two appendices. Mr. Koch also prepared testimony entitled The Rebuttal Testimony of Donald N. Koch which consists of 14 pages of questions and answers. I ask that the direct testimony and rebuttal testimony of Mr. Koch be incorporated into the record as if given orally today.

A.L.J. LECAKES: So granted. That will be the file in the Company Direct Testimony folder that appears as Koch, K-O-C-H, Direct Testimony and The Koch Rebuttal Testimony in the Company Rebuttal Testimony folder. The affidavit will be marked as Exhibit 52.

DIRECT TESTIMONY OF DONALD N. KOCH

1 Q. Please state your name and business address.

2 A. My name is Donald Koch. My business address is 6363 Main Street,

3 Williamsville, NY 14221.

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

5 A. I am employed by National Fuel Gas Distribution Corporation ("Distribution" or the

6 "Company") as a Rate Analyst II in the Rates and Regulatory Affairs Department.

7 Q. Please state briefly your educational background and experience?

8 A. I received a Bachelor of Science Degree in Business Administration from

9 SUNY Geneseo in May 2004. I received a Masters of Business

10 Administration with a specialization in Accounting/Finance from St.

11 Bonaventure University in December 2009. Prior to joining Distribution, I

12 worked in the banking industry for 11 years, specializing in various

13 compliance and financial roles. In June 2015, I was hired by Distribution in

14 my current position as a Rate Analyst II in the Rates and Regulatory Affairs

15 Department.

16 Q. Have you previously testified before this Commission?

17 A. No.

18 Q. Have you testified before any other regulatory agency?

19 A. Yes, I have testified before the Pennsylvania Public Utility Commission in

20 purchase gas cost proceedings.

21 Q. What is your responsibility in this proceeding?

22 A. I am responsible for the Historic Rate Base, the Rate Year Rate Base, and the

23 Estimated Average Net Plant .

24 Q. Please describe Exhibit___(DNK-1).

1 A. Exhibit___(DNK-1) consists of nine schedules. It is a statement of annualized
2 rate base for the historical period ended December 31, 2015 for Distribution's
3 New York Division.
4 Q. Please describe Schedule 1 of Exhibit___(DNK-1).
5 A. This schedule is a summary of annualized rate base for the historical year ended
6 December 31, 2015. Detailed computations for components on Schedule 1
7 appear in Schedules 2-9. Please refer to the testimony of Mr. Rizzo for detailed
8 computations of Deferred Income Tax and TRA - Uncollectibles.
9 Q. Please describe Schedule 9 of Exhibit___(DNK-1).
10 A. Schedule 9 consists of three sheets and shows the comparison of the historical
11 earnings base to capitalization ("EB/CAP") for the twelve months ended
12 December 31, 2015. Sheet 1 shows the development of the historical earnings
13 base for Total Distribution, Sheet 2 shows the development of the historical
14 earnings base for the New York Division, and Sheet 3 shows the average
15 capitalization for the twelve months ended December 31, 2015.
16 Q. Please describe the development of cash working capital and its history with the
17 Commission.
18 A. In the 1960's the preferred method of calculating the cash working capital
19 ("CWC")[1] was the lead lag study. In the Consolidated Edison case (Case 25342)
20 the Commission adopted the FPC method (1/8 of O&M) and stated:

21 We agree with Staff and the Examiner, however, that the
22 lag method of computing working capital has become so
23 cumbersome as to make the time and expense of such a study
24 disproportionate to whatever advantages the method may have
25 in terms of accuracy. This is particularly true as applied to Con
26 Ed rate cases...We further agree with Staff that we should use
27 our decision in this case to discourage reliance upon the lag
28 method in future cases. We do not, however, wish to lay down a

[1] Cash Working Capital historically has referred to the amount of cash needed on hand by the Company to pay its day to day operating expenses for the time period during which the Company has provided service and has not yet been fully paid for that service.

> blanket rule that the lag method may never be appropriate. Indeed, Staff recognizes that this method may be the best measure of telephone Company working capital requirements. What we do hold is that in future rate proceeding involving Consolidated Edison, we will direct our Staff to present FPC-type working capital studies; and the burden will be on the proponent of any "lag-method" working capital study to demonstrate affirmatively the superior accuracy of such a study as compared with the FPC-type analysis. In proceedings involving other companies, we will give careful consideration to FPC-type studies, and we will not utilize lag studies merely because such studies appear in the record.

In the mid 1970's the Commission became concerned that the FPC method was not sufficiently precise and it investigated using a supplementary type of analysis that would adjust the rate base, which included the FPC working capital formula, to equal no more than the amount of investment of the security holders, including short term investors, in the utility. And so the EB/Cap was born. The theory behind the EB/Cap is that reasonable rates require that a utility be allowed to earn no more than a fair return on the investment dedicated to public service. The investment, which is entitled to a fair return, is not the investment by the Company in assets dedicated to public service. Rather it is the investment by the holders of the capital of the Company, that is, the holders of the common equity and the debt of the Company, which includes short term investors. The Commission reasoned that if the utility was allowed to earn a return on a rate base which is greater than its capitalization, assuming the same rate of return, the equity return on the rate base would be greater than the investors' capital.

Q. Does the EB/Cap adjustment make sense for Distribution?

A. No. As all of the elements of Distribution's rate base are specifically calculated based upon amounts included on Distribution's books, the only estimated item,

1 the CWC, must then be the item that is causing the difference between the
2 earnings base and the capitalization. The estimate of cash work capital, as
3 adjusted by the EB/Cap adjustment, however, does not properly reflect the fact
4 that Distribution is part of a company that is regulated by two different
5 jurisdictions, this Commission and the Pennsylvania Public Utilities Commission
6 (PUC). Because of the two different jurisdictions, the capitalization of the total
7 Company has been allocated based upon the determination of Distribution's total
8 earnings base compared to the calculation of the total Company's earnings basis.
9 This allocation of capitalization, however, produces anomalies due to the different
10 ways items are treated by the two different commissions. For example, an item
11 that is regularly included in rate base in NY might not be allowed in rate base in
12 Pennsylvania. The NY settlements during the last 10 years have created many
13 deferral accounts that are monies provided by New York ratepayers and held,
14 per the joint proposals, for future return to those New York ratepayers. Some
15 examples of these deferral accounts include Research Development and
16 Demonstration and Site Remediation costs.
17 Q. Have you applied the EB/Cap adjustment to the Company's Rate Base?
18 A. Yes, I have employed the EB/Cap adjustment because the Commission has
19 disallowed other methods of measure, such as Lead Lag study, which
20 Pennsylvania requires. Because the Lead Lag study can now be accurately
21 performed given the advance of computer technology since the adoption of the
22 FPC working capital formula, there is really no need to use either the FPC
23 method or the EB/Cap check on its accuracy.
24 Q. Please describe Exhibit___(DNK-2).
25 A. Exhibit___(DNK-2) consists of five schedules. It is a statement of rate base
26 calculated for the Rate Year ending March 31, 2018.

1 Q. Please describe Schedule 1 of Exhibit___(DNK-2).

2 A. This schedule is a summary of rate base for the Rate Year ending March 31,

3 2018. Detailed computations appear in Schedules 2 – 5.

4 Q. Please describe the $(258,976,000) Total Deferred Income Taxes amount shown

5 on Schedule 1.

6 A. Please refer to the testimony of Mr. Rizzo for detailed computations of Total

7 Deferred Income Taxes.

8 Q. Please describe the $266,000 Deferred PSC Assessment amount shown on

9 Schedule 1.

10 A. I have reflected the historic amount because the expense has been reflected as

11 the latest known invoice.

12 Q. Please describe the $8,088,000 TRA Impact - Uncollectibles amount shown on

13 Schedule 1.

14 A. Please refer to the testimony of Mr. Rizzo for detailed computations of TRA

15 Impact - Uncollectibles.

16 Q. Please describe the $2,303,000 NRG Amortization amount shown on Schedule 1.

17 A. The $2,303,000 NRG Amortization amount relates to the Company's costs

18 incurred relative to the repowering of the Dunkirk Power Plant with Natural Gas

19 that has been put on hold due to a pending law suit. The $2,303,000 consists of

20 $1,418,000 of Preliminary engineering costs and $886,000 of Right of Ways.

21 Q. Have any other amounts relating to the NRG project been included in Schedule

22 1?

23 A. Yes, $1,321,000 of pipeline has been included in the Material and Supplies

24 balance.

25 Q. Please refer to Schedule 2 of Exhibit___(DNK-2). What does this schedule

26 show?

1 A. Schedule 2 of Exhibit 2 calculates the CWC allowance for the twelve months
2 ended March 31, 2018 by dividing total projected operations and maintenance
3 expense, excluding purchased gas, by eight. This is the FPC working capital
4 methodology, which has been consistently used by the Commission in prior
5 cases.
6 Q. Please explain Schedule 3 of Exhibit___(DNK-2).
7 A. Schedule 3 sets forth prepayments for Property Taxes, Other Insurance and AGA
8 Dues. The prepaid property taxes forecast is based upon the property tax
9 expense forecast. I have inflated the historic amount of rate base for prepaid
10 other insurance and AGA Dues as those items are included in the inflation pool.
11 Q. Please describe the Statement of Deferred Site Investigation and Remediation
12 Expenses on Exhibit___(DNK-2), Schedule 4.
13 A. Exhibit___(DNK-2), Schedule 4 shows the expected deferral balance (net of tax)
14 for site investigation and remediation during the thirteen months ending March 31,
15 2018. Please refer to the testimony of Ms. Friedrich-Alf for more detail on the
16 calculation of this balance.
17 Q. Please describe Schedule 5 of Exhibit___(DNK-2).
18 A. This schedule details the monthly balances of the Deferred Research
19 Development and Demonstration costs. Please refer to the testimony of Ms.
20 Friedrich-Alf for more detail on the calculation of this balance.
21 Q. Please describe Exhibit___(DNK-3), Schedule 1.
22 A. Schedule 1 consists of four sheets and shows the estimated average net plant at
23 March 31, 2018. Sheet 1 shows the derivation of estimated average plant in service
24 at March 31, 2018. I began with the actual plant in service and actual reserve for
25 depreciation at December 31, 2015. Based upon the Company's construction
26 budget I estimated the monthly changes from January 2016 through March 2018 to

1 arrive at the projected average net plant of $1,490,801,000 at March 31, 2018. I
2 have also included the non interest bearing construction work in progress and
3 construction completed not yet classified at December 31, 2015.
4 Sheet 2 shows similar calculations for estimated average reserve and
5 shows the estimated average net plant at March 31, 2018. Mr. Spanos provided the
6 reserve at March 31, 2018.
7 Sheet 3 shows the Projected Spending Amount for Fiscal Year 2016 and
8 the construction budget for Fiscal Years 2017 - 2020 provided by Mr. House by
9 month and plant type.
10 The remaining sheet of Schedule 1 of Exhibit___(DNK-3) supports the
11 estimate of the net plant.
12 Q. How are the expenses of the new SAP ("Barcelona") CIS system reflected in
13 Schedule 1, Sheet 3?
14 A. The new SAP CIS system is scheduled to be in service May 9, 2016. Total NY
15 distribution project expenses of $38,199,000 are reflected at May 31, 2016, with an
16 additional $7,652,000 put in service at March 31, 2017.
17 Q. Have Accelerated Leak Prone Pipe replacement costs been reflected in Schedule
18 1, Sheet 3?
19 A. Yes, please refer to the testimony of Mr. House for a detailed discussion regarding
20 Accelerated Leak Prone Pipe replacement costs.
21 Q. Does this conclude your testimony?
22 A. Yes, it does.

Case 16-G-0257 Rebuttal Testimony of Donald N. Koch

Q. Please state your name and business address.

A. My name is Donald N. Koch. My business address is 6363 Main Street, Williamsville, New York 14221-5887.

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

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

Q. Have you testified previously in this case?

A. Yes. I provided Direct Testimony, Exhibits and workpapers regarding the Company's Historic Rate Base, the Rate Year Rate Base, and the Estimated Average Net Plant.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut several adjustments presented by New York State Department of Public Service Staff ("Staff") Accounting Panel and Staff Gas Rates Panel in regards to Earnings Base in Excess of Capitalization ("EB/CAP") and Average Net Plant in Service. I will also address other Rate Base adjustments presented by members of Staff.

<u>EARNINGS BASE IN EXCESS OF CAPITALIZATION (EB/CAP)</u>

Q. When describing how the Company calculated its EB/CAP adjustment on page 39 of the direct testimony of the Staff Accounting Panel, the Panel states "the Company first took the New York Earnings Base ($643.923 million) as a percentage of total National Fuel Gas Corporation (or the Parent) earnings base ($866.880 million), or 74.28%." Is this an accurate statement?

A. No. First, as a matter of clarification, the name of Distribution's parent is National Fuel Gas Company, not "National Fuel Gas Corporation" as incorrectly stated by Staff. Second, the New York earnings base ($643.923 million) is taken as a percentage of total National Fuel Gas Distribution Corporation ($866.880 million), not the total "National Fuel Gas Corporation (or the Parent)" as characterized by the Staff Accounting Panel.

Q. Does the Staff Accounting Panel mischaracterize the New York earnings base percentage relationship anywhere else in its direct testimony?

A. Yes. The Staff Accounting Panel states on page 43 of its direct testimony "it is necessary to calculate the New York earnings base as a percentage of the Parent's total earnings base". This is not correct;

the calculation should be Distribution's total New York earnings base as a percentage to Distribution's total earnings base, not National Fuel Gas Company's (or "the Parent's") total earnings base.

Q. The staff Accounting Panel has proposed an adjustment to EB/CAP to include several "NY Only" items in the ***capitalization*** calculation of EB/CAP. Do you agree with this adjustment?

A. No. The allocation of Distribution's NY earnings base percentage (Distribution's NY earnings base/Distribution's total earnings base) to total capitalization has been well established in previous cases. The Company presented an EB/CAP adjustment based on "NY Only" capitalization in prior rate cases (93-G-0756 and 04-G-1047) but Staff rejected that approach each time.

Q. Would you please explain Staff's position presented in the 93-G-0756.

A. In Case 93-G-0756, on pages 30 - 31 of Staff witness Wojcinski's direct testimony in that case, Mr. Wojcinski testified that it is necessary to allocate capitalization between the NY and PA divisions of Distribution because "National Fuel Gas Corporation does not keep separate balance sheets for the New York and Pennsylvania

Divisions of the Distribution Corporation. The methodology I propose was accepted by the Commission in Case 26929, National Fuel Gas Distribution Corporation-Gas Rates (Opinion 76-24) as a fair way of allocating capital and has been used since 1976."

Q. Did Staff witness Wojcinski further describe his understanding of this allocation in Case 93-G-0756?

A Yes. Staff witness Wojcinski testified further on page 31 of his direct testimony in that case that "It is impossible to charge ***capital*** directly to either Pennsylvania or New York. However, the jurisdictional identity of ***assets*** that are financed by capital can be determined. By taking the total of New York jurisdiction's assets and dividing it by the total assets of the Distribution Corporation, a percentage can be calculated. Based on this percentage, ***capital*** would be allocated to each jurisdiction." (emphasis added). I have provided Mr. Wojcinski's direct testimony from Case 93-G-0756 in Exhibit ___ (DNK-4).

Q. What was the result in the final Order in Case 93-G-0756 concerning the Earnings Base/Capitalization Adjustment?

A. As provided in Exhibit ___ (DNK-5) the final Order in Case 93-G-0756 states on pages 34 - 35 that "In this case the Judge accepted staff's

recalculation of the earning base/capitalization adjustment National Fuel presented. Staff corrected the company's calculation of its ***total capitalization*** and applied a net-of-tax return to the take-or-pay costs that the company has been deferring.

The company has not excepted to the Judge's recommendation; however, staff has requested that this matter be put to rest for all time. Staff requests that Judge's finding be expressly endorsed so National Fuel will not relitigate the issue in a future rate case.

Staff has properly calculated the earnings base/capitalization adjustment to be applied here." (emphasis added)

Q. Would you please explain staff's position presented in Case 04-G-1047.

A. As the Company explained in its response to information request DPS-94 in this proceeding, in Case 04-G-1047, Staff once again rejected the Company’s proposed approach to allocate "NY Only" items in the Capitalization calculation of EB/CAP. Staff witness Wojcinski's testified in that proceeding (Exhibit ___(DNK-6) at pages 4-5), that the NY Only method "produces an unreasonable allocation

of capital to the New York Division of the Distribution" company. Mr. Wojcinski further explains "[T]he calculation of the EB/CAP requires two steps;(1) the allocation of capital between the New York & Pennsylvania divisions of the Distribution Corporation and (2) a comparison of that allocated New York capital to the New York Division earning's base. Step 1 is necessary because financings of capital are made by the Parent, who transfers the proceeds to the total Distribution Company. Allocations of these Financings (capital) are not made to specific divisions. Since it is possible, however, to determine the level of assets in each division, we use that relationship to allocate capital."

Q. How did the Company calculate Capitalization in its last rate case, Case 07-G-0141?

A. The Company calculated Capitalization in accordance with the Commission's final Order in Case 93-G-0756, which is to allocate the NY to Total Distribution earnings base percentage to ***total capitalization***.

Q. Did Staff agree with this methodology in Case 07-G-0141?

A. Yes.

Q. Do you agree with Staff' characterization in this proceeding of how the Company prepared EB/CAP in its last rate case, Case 07-G-0141?

A. No. On page 39 of the Staff Accounting Panel testimony, Staff mischaracterizes the Company's response to DPS-94 relating to Case 07-G-0141.

Q. Please explain.

A. DPS-94 asked the Company to "Provide an explanation why the Company applied the allocation of NY earnings base, to total earnings base (74.28%), to the total capitalization, rather than using the NY Only capitalization in their EB/CAP calculation." The portion of the Company's that related to Case 07-G-0141 states "In Case 07-G-0141, the Company did not employ a NY-only capitalization. See Direct Testimony of Regina L. Truitt at 38-39. Staff witness Wojcinski stated that he agreed with Ms. Truitt's EB/CAP method."

Q. In your opinion, how did Staff's testimony mischaracterize the Company's response to DPS-94?

A. Instead of using the direct response given by the Company to DPS-94, Staff utilized an excerpt of Ms. Truitt's testimony that first argues

the merits of using a NY only capitalization before stating that was not the methodology she used to calculate capitalization in Case 07-G-0141. In Case 07-G-0141, the Company followed the methodology of total capitalization as Ordered in Case 93-G-0756.

Q. Please comment on the Staff Accounting panel's testimony on page 41 that the Company presented the EB/CAP adjustment differently in Case 13-G-0136 than it had in the past and that "[t]he Company used a two year average in its EB/CAP adjustment because the Company indicated the EB/CAP adjustment has varied widely since rates were last set in the 2007 Rate Order."

A. There are inherent differences between a rate case extension (such as in Case 13-G-0136) than that of a full rate case proceeding (as in this case, 16-G-0257). A rate case extension is much narrower in scope and normally involves settlement between the parties on issues of a smaller scale. A full rate case proceeding is a comprehensive process involving litigated positions between parties. Therefore, Staff's testimony regarding the Company's treatment in of EB/CAP in Case 13-G-0136 is not relevant to this case, 16-G-0257. Also, Staff fails to take in account that the Company calculated the

Capitalization piece of EB/CAP in this case in the same manner as Ordered in 93-G-0756 and in the Company's last filed rate case, Case 07-G-0141.

Q. In the current case, did the Company make any adjustments to the methodology or how it calculates the capitalization piece of the EB/CAP calculation from the methodology of Case 93-G-0756 order or Case 07-G-0141?

A. No.

Q. What are you recommending?

A. I recommend that the Commission reject the Staff Accounting Panel's adjustment to include specific "NY Only" adjustments to the Capitalization piece of the EB/CAP calculation. The Commission should follow precedent, utilize the methodology from Case 93-G-0756, Case 04-G-1047, and Case 07-G-0141, and accept the Company's calculation for EB/CAP of $9,366,000.

<u>AVERAGE NET PLANT IN SERVICE</u>

Q. The Staff Gas Rates Panel made the following modifications to the Company's Net Plant in Service model: 1) adjustments to the capital budget; 2) adjusted depreciation rates; and 3) staff perceived

"corrections" to the Company's model. Do you agree with these adjustments?

A. No, I will address each adjustment separately.

Q. The Staff Gas Rates Panel adjusted the capital budget by allocating New York Distribution's portion of $5mm in cost reduction of the Barcelona CIS project and by reducing Leak Prone Pipe replacement unit costs by $1.39mm. Why do you disagree with these adjustments?

A. While I agree there is a $5mm in cost reduction of the total Barcelona CIS project and agree with the 71% allocation factor that Staff used to allocate the New York Distribution portion of the cost reduction, Staff utilization of $59,311,000 for the total project cost of is incorrect. The latest total estimated total project cost is $60,000,000 of which $42,600,000 is applicable to New York (Exhibit ___(DNK-7)). As a standalone adjustment, correcting this error would adjust Staff's Net Plant calculation to $902,934m, an increase of $465m.

In regards to the $1.39mm reduction in Leak Prone Pipe Replacement unit costs, please refer to the rebuttal testimony of Mr. House.

Q. The Staff Gas Rates Panel adjusted the depreciation rates of 3 accounts: 367.10; 375; and 376.4. Please discuss.

A. Please refer to the rebuttal testimony of Mr. Spanos for a detailed rebuttal of the adjusted depreciation rates.

Q. Staff made adjustments to the Company's Net Plant in Service model that they deemed were "Corrections" to the model's output. These adjustments consisted of reducing depreciation accrual expenses by $800,000 and reducing the total reserve for depreciation balance by $5.118mm. Why do you disagree with these adjustments?

A. Both depreciation accrual expenses and total reserve for depreciation at March 31, 2018 are calculations provided to the Company by Mr. Spanos of Gannet Fleming. Mr. Spanos was retained by the Company to complete an in depth depreciation study that includes the calculations above and serve as expert witness in the area of depreciation. As an expert in the area of depreciation, the Company relies upon his calculations as inputs in its Net Plant in Service model. In order to properly utilize and match the calculations provided to the Company by Mr. Spanos and to accurately calculate the Net Plant (using ½ of March 2017 and ½ of March 2018 requires monthly

numbers), this required adding an additional $800,000 of depreciation expense to the Company's model output and an additional $5.118mm to the total reserve for depreciation. If the Company did not employ these adjustments within its Net Plant in Service model, it would diminish and flaw the results of the work completed by Mr. Spanos.

Rate Base

Q. Staff adjusted total Working Capital in Rate Base by $(822)m. Do you agree with this adjustment?

A. No. Working Capital is calculated using a 1/8 O&M formula. The value of Working Capital should reflect the O&M included in the final Order in this proceeding.

Q. Staff adjusted total Prepayments in Rate Base by $(408)m for property tax adjustments. Please discuss.

A. Please refer to the rebuttal testimony of Mr. Rizzo for a complete discussion of the property tax adjustment affecting prepayments. . This will be updated to properly reflect the amount included in the final Order in this proceeding.

Q. Staff adjusted total Accumulated Deferred Income Taxes (ADIT) in Rate Base by $1.350mm for liberalized depreciation and excess

ADSIT adjustments. Please discuss.

A. Please refer to the rebuttal testimony of Mr. Rizzo for a complete discussion of the Accumulated Deferred Income Tax (ADIT) adjustments. This will be updated to properly reflect the amount included in the final Order in this proceeding.

Q. Included in the Rate Base adjustments for ADIT was an adjustment to Uncollectibles expense for $(366)m. Please discuss.

A. Please refer to the rebuttal testimony of Ms. Frank for a complete discussion of Uncollectibles expense. This will be updated to properly reflect the amount included in the final Order in this proceeding.

Q. The SIR Panel made adjustments to the SIR average balance reducing it by $(340)m. Do you agree with these adjustments?

A. The rebuttal testimony of Ms. Friedrich-Alf provides a complete discussion of SIR average balance adjustments. This will be updated to properly reflect the amount included in the final Order in this proceeding.

Q. The Staff Accounting Panel made an adjustment to include the unamortized Rate Case expense in Rate Base in the amount of

$94m. Do you agree with this adjustment?

A. Partially. Staff's adjustment to amortize rate case expense over 3 years should be rejected. Please refer to the rebuttal testimony of Ms. Friedrich-Alf for a complete discussion of the amortization period of the Rate Case expense. The Company agrees to include the unamortized balance, if any, in Rate Base.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, at this time.

A.L.J. LECAKES: Were there exhibits attached to Mr. Koch's testimony?

MR. NICKSON: There were, Your Honor. Attached to the direct testimony of Mr. Koch are three exhibits identified as DNK1 through DNK3 and attached to the rebuttal testimony of Mr. Koch are four exhibits which were identified as DNK4 through DNK7. I would ask that each of those documents be marked for identification.

A.L.J. LECAKES: I also have on the exhibit list work papers as separate exhibits for DNK1, work papers for DNK2, and work papers for DNK3. Is that correct?

MR. NICKSON: That is correct, Your Honor. Thank you.

A.L.J. LECAKES: Okay. So mark Exhibit 53 for DNK1, 54 for DNK2, 55 for DNK3, 56 for DNK1 work papers, 57 for DNK2 work papers, 58 for DNK3 work papers, 59 for DNK4, 60 for DNK5, 61 for DNK6, 62 for DNK7. Next witness?

MR. NICKSON: The next witness is Donald A. Parr. Mr. Parr prepared testimony entitled The Rebuttal Testimony of Donald A. Parr which consists of 12 pages of questions and answers and I ask that the rebuttal

testimony of Mr. Parr be incorporated into the record as if given orally today.

A.L.J. LECAKES: So granted. That will be Parr, P-A-R-R, Rebuttal Testimony in the Company Rebuttal Testimony folder. The exhibit will be marked as 63 -- I'm sorry the affidavit will be marked as 63.

Q. Please state your name and business address.

A. Donald A. Parr. My business address is 8955 Guilford Rd #260, Columbia, Maryland 21046.

Q. Please state your business affiliation**.**

A. I am employed by Black & Veatch Management Consulting, LLC ("Black & Veatch") as an Associate Vice President and I lead its Customer Operations & Billing Solution Practice.

Q. Please describe Black & Veatch management consulting.

A. Black & Veatch is a global engineering, consulting, construction, and operations company specializing in infrastructure development in energy, water, telecommunications, management consulting, federal, and environmental markets. Black & Veatch Management Consulting, LLC is a wholly owned subsidiary of Black & Veatch created to provide clients with comprehensive financial, technology and strategic consulting services within the electric, oil and gas and water markets. Our consulting expertise is backed by deep industry, technical and engineering experience that enables us to understand and address the most complex issues facing our clients.

Q. On whose behalf are you submitting this rebuttal testimony?

A. I am appearing on behalf of the National Fuel Gas Distribution Corporation ("Distribution" or the "Company").

Q. Have you previously provided testimony in this proceeding?

A. No.

Q. Please describe your educational background and business experience**.**

A. A detailed summary of my educational and professional experience is provided in Exhibit_(DAP-1). I have a B.A. degree in Economics and a B.S. degree in Finance from the University of Maryland, College Park. My relevant fields of study include corporate finance, management information systems and data analytics. I have provided consulting services to public and investor owned utilities since 1989. I have provided these services through major consulting firms including Andersen Consulting (now Accenture), Arthur Andersen Business Consulting, BearingPoint and Black & Veatch. My area of focus has been Customer Operations & Billing for the vast majority of my career. I have been involved in seventeen (17) Customer Information System implementation projects at electric, gas and water utilities similar to the recent Barcelona Project undertaken by Distribution.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is two-fold. First, to address certain issues related to the costs associated with the operation and maintenance of the new Customer Information System solution ("CIS" or "solution") implemented by Distribution in May 2016 which were raised by Mr. Haslinger of the New York State Department of Public Service staff ("Staff"). Second, to address the additional 1% productivity adjustment recommended by the Staff Policy Panel to account for future efficiencies, benefits, or cost savings which may be realized by the Company as a result of the new system's implementation. The scope of the new CIS solution includes CIS and Work Management from SAP and other software providers.

Q. **P**lease summarize your rebuttal testimony**.**

A. My rebuttal testimony provides evidence that Distribution's proposed CIS Support Plan and Associated Costs as presented by Distribution witness, Mr. Patrick Boyle, are consistent with:

1. My expert knowledge of the expected costs to implement a CIS and MWM solution in a utility with characteristics similar to Distribution's;
2. My personal experience in the planning and execution of initial post production support related to CIS solutions for utilities;
3. The experience conveyed to Distribution by other utilities as presented in the rebuttal testimony of Patrick T. Boyle;
4. The industry experience of Zarko Sumic of the Gartner Group as presented in the rebuttal testimony of Mr. Boyle;

and, that the additional one percent productivity adjustment based on the CIS and MWM system's implementation is inappropriate.

Q. How much do utilities spend on the implementation of similar CIS solutions to the one implemented by Distribution?

A. The CIS solution implemented by Distribution has two major components – Customer Information System and Mobile Work Management System. The industry estimates for the implementation of a CIS solution is $90-120 per customer for utilities similar to Distribution. The industry estimate for the implementation of a Mobile Work Management System is $8,000 – 12,000 per user. The table below illustrates the industry estimated budgetary pricing for Distribution:

System	Estimating Metric	Cost Per	Budgetary Implementation Price
CIS	740,000 Customers	$90-120	$66-88 Million
MWM	400 Users	$8,000-12,000	$3 – 5 Million
		Total	$69 – 93 Million

The industry estimating factors imply that a prudent budget for this solution for Distribution should be $69M-93M. The factors that go into the range are complexities of the market(s) that the utility operates in, number of customers and customer mix between industrial, commercial and residential accounts.

Q. Distribution spent $60 Million on the implementation project for the new CIS Solution. Please express your opinion on that expenditure?

A. As shown above, utilities of similar size to Distribution have spent between $69M and $93M implementing solutions like the one implemented by Distribution. Distribution's expenditure of $60 Million is on the lower end of the range of project expenditures. There are a number of recent high profile overruns at utilities such as Seattle City Light, Los Angeles Department of Public Works or Emera Maine. Each of these utilities was significantly over budget and over the estimated range above. Based on my experience, Distribution was highly effective and prudent in its CIS solution expenditure.

Q. Do utilities experience savings related to a CIS as soon as they go-live with the new solution?

A. No. Implementing and operating a new CIS, introduces many new processes that are required to operate the solution and it takes significant time and experience with the solution to stabilize the solution.

Q. Should Distribution's CIS replacement project have been more focused on not just replacing all required functionality with a modern system, but in striving to add additional automation and features which might have delivered more efficiencies and benefits?

A. There are risks of replacing an antiquated legacy system with an SAP system and the project taking on too much scope as part of that replacement. There are many examples in the utility industry where projects of similar scope and complexity have gone over budget and / or over schedule. The examples cited above at Seattle City Light ($56M budget vs. $98M actual, 12 months delayed) and Emera Maine ($17M budget vs. $30M actual), point to poor project management and control of scope that led to 50%-80% overruns and delays of up to 12 months. Distribution's approach was prudent and is evidenced by their delivery of a functional system at a cost which is on the low end of industry norms.

Q. When do utilities experience opportunities for performance improvement?

A. The typical experience of utilities with new CIS is that phase one of support is spent stabilizing the solution. The next phase of support is spent understanding areas where optimization can be made, determining the value and priority of those changes and creating an action plan to implement those changes. The final phase of support is when noticeable improvements to processes can be made that begin to have an impact on the support and operating costs of the solution. Based on

my experience, Distribution will still be in the first or second phase of support during this rate case period.

Q. Are the additional CIS support costs proposed by Distribution associated with the deployment of its new CIS reasonable?

A. Yes. With respect to Distribution's proposed level of expenses, there are specific and tangible services provided that are necessary to support the implementation of the new CIS. The addition of ten (10) Full Time Equivalents ("FTEs")[1] for a utility the size and complexity of Distribution is fully justifiable and reasonable.

Q. What are the areas that support the increase in support costs for distribution's new CIS?

A. There are five areas which require an increase in Distribution's CIS support costs. These five areas include:

1. Support of multiple CIS systems (IT Support staff).
2. Support for new development tools (IT Support Staff).
3. Support for configuration and environments (IT Support Staff).
4. Support for completion of exception work items (Consumer Business Staff).
5. Reduced productivity of Consumer Business and Field Customer Service staff resources.

These five areas should be used to assess the proposed expenses of Distribution's Support Plan to determine whether the proposed plan is just and reasonable with regard to the level of expenses included in each year of the proposed plan.

[1] See the direct testimony of Patrick T. Boyle, p. 51, lines 17-19.

Q. Is Distribution maintaining its legacy CIS for a time in conjunction with the new CIS?

A. Yes, it is my understanding that the Company will be operating both systems together for a limited time.

Q. What is the justification for the support of multiple CIS systems?

A. Distribution's legacy CIS has been left in read only mode to support the historical inquiry into customer's accounts. While the Barcelona project team converted one year's worth of meter and billing history, there are customer inquiries that require history beyond the one-year period that was initially reflected in the new CIS. This is a common practice for utilities moving to a new CIS. Based on my experience, most utilities that are replacing a CIS do an analysis that shows that the complexities of converting more than one year's worth of history is extremely cost prohibitive due to the rigid historical dependencies built into new CIS packages like SAP.

The support for this area is usually 1-2 FTEs for utilities similar to Distribution.

Q. What is the justification for the support related to new development tools?

A. With the implementation of the SAP solution, there are a number of new tools and programming languages that need to be supported by the utility. These tools include SAP's Process Integrator and Solution Manager. These are necessary tools in the management of changes to configuration and extensions specific to Distribution's patches and upgrades to the core software from SAP. The SAP solution requires the use of two primary programming languages – ABAP and

JAVA. The introduction of these tools and languages typically adds 5-7 FTEs in the programming and development infrastructure support area.

Q. What is the justification for the support related to configuration and environments?

A. With the SAP solution, there is a significant effort required to manage the technical and functional configuration of the solution. The technical configuration impacts how the solution operates within its technical architecture including support for production, training, test and development environments. The technical architecture includes hardware, operating system, communications and database structures – all of which are new to Distribution's CIS team. The functional configuration impacts how the solution supports the business processing and operational needs. Examples of functional configuration include rate structures, application and process security, and credit and collections timelines that drive CIS processing. As the solution matures, Distribution's configuration resources will need to enhance the initial configuration to optimize the supported operational and business processes. The maintenance of the technical configuration typically adds 2-3 FTEs in the environment administration area of the CIS support team. The maintenance of the functional configuration typically adds 3-6 FTEs to the functional area of the CIS support team.

Q. What is the justification for the support related to completion of exception work items for Consumer Business Staff?

A. Enterprise solutions like SAP have significantly more accounting controls built in than typical purpose built custom solutions such as Distribution's legacy system.

These accounting controls ensure that all records are processed by maintaining a strict accounting for all records and accounts to be processed. These controls allow for the integrity of the business processes to be maintained. When an exception to an account level control occurs, an exception is generated in to an electronic work queue. The solution manages the exception lifecycle and requires these to be resolved in a timely manner. Because there are more exceptions generated and these exceptions need to be resolved, there is an increased workload created. The increased workload of resolving exceptions typically adds 3-10 FTEs to the Consumer Business area.

Q. What is the impact and rationale for the reduction in productivity of Consumer Business and Field Customer Service staff resources?

A. Enterprise solutions like SAP have a different look and feel, business processes and underlying data model that have a significant learning curve even for experienced resources. Based on my experience on projects of similar scope and organizations of similar make up to Distribution's, even with an effective Change Management program that includes training and other education efforts, the productivity of the Consumer Business organization (call center and back-office processing) is typically reduced to 60% of its previous level when a new CIS is deployed.

To achieve the service levels experienced prior to the new CIS, the Consumer Business organization typically requires the addition of 6-15 FTEs in years one and two, depending on the complexity. Of the added resources, typical organizations permanently (year three and after) add 2-4 FTEs in the Consumer

Business team. To achieve the service levels experienced prior to the new MWM, the Field Customer Service organization typically requires the addition of 5-10 FTEs in years one and two, depending on the complexity. Depending on the utilities' long term needs, these FTEs are added as employees and other times as contract or temporary workers. Of the added resources, typical organizations permanently (year three and after) add 3-5 FTEs in the Field Customer Service team.

Q. Please summarize your conclusions related to the support organization required for Distribution's new CIS.

A. Distribution's proposed support organization and related expenditures for its new CIS appear to be reasonable and prudent based on my experience with CIS implementation activities for similarly situated utilities. Based on each of the impacted areas enumerated above, the range of staff resource additions required by a utility such as Distribution is summarized in the table below.

SUPPORT AREA	REQUIRED INCREASE IN FTEs
1. Multiple CIS systems (IT Support Staff)	1-2
2. New development tools (IT Support Staff)	5-7
3. Configuration and environments (IT Support Staff)	5-9
4. Completion of exception work items (Consumer Business Staff)	3-10
5. Reduced productivity of Consumer Business and Field Customer Service resources	2-25
TOTALS	16-53

In my opinion, based on systems I have been involved with implementing, the CIS support plan and related expenditures submitted by Distribution in this proceeding falls at the lower end of the range of increases in FTEs identified above and are certainly reasonable for the system Distribution installed.

Q. **A**t pages 14 to 15 of their testimony, the Staff Policy Panel states:

> We propose to impute an additional 1% productivity, thus bringing total productivity to 2% for the Rate Year. The additional productivity is intended to capture the unquantified cost savings associated with the new CIS system and the discontinuation of the old legacy system. Increasing the productivity to 2% results in a $0.76 million reduction to Rate Year Operation and Maintenance (O&M) expense. We believe this amount is conservative, considering the significant opportunities for the Company to achieve productivity and savings.

Do you agree with Staff's recommendation?

A. No. Based on my foregoing testimony, I recommend that the New York Public Service Commission both (1) approve the proposed support expenditure as enumerated in Distribution's plan and (2) reject Staff's additional productivity adjustment. In my expert opinion, Staff's additional productivity adjustment of 1% is not realistic or supported by the real world implementation of CIS systems which, as I have clearly demonstrated, actually reduce productivity in the first few years of their operation.

Q. The period for which rates are being set in this proceeding are the 12 months ending March 31, 2018. Do you believe it is reasonable to expect that the implementation of the new CIS system will produce any net productivity savings in this period?

A. No, I do not. As I explained in my testimony, in my experience utilities do not even begin to see productivity gains appear until sometime in the third year after the system commences operation. Given that the Company's CIS system only "went live" on May 9, 2016, it is unreasonable to impute any additional productivity in the Rate Year arising from the new CIS.

Q. Does this complete your rebuttal testimony?

A. Yes, at this time.

A.L.J. LECAKES: Were there exhibits attached to that testimony?

MR. NICKSON: Yes, Your Honor. Attached to the testimony of Mr. Parr is one exhibit which was identified as DAP1 and I ask that it be marked for identification.

A.L.J. LECAKES: So marked. It will be marked as Exhibit 64. Next witness?

MR. NICKSON: Your Honor, before we move on --

A.L.J. LECAKES: Yes.

MR. NICKSON: -- could I go back to Mr. Koch? I just want to note for the record that the exhibit list that we provided to Your Honor had minor typographical errors and the exhibits that you just identified as 60 through 62, on the exhibit list are attached -- are associated with Kevin D. House.

A.L.J. LECAKES: Oh I'm sorry.

MR. NICKSON: They should be Donald N. Koch -- or Koch. So that's on page 19 --

A.L.J. LECAKES: Oh okay. So on page 19, there is an exhibit listed DNK-5, DNK-6, and then exhibit listed DNK-7. The identification in that page lists Kevin D. House as the witness, but it

really was Donald Koch.

MR. NICKSON: Correct.

A.L.J. LECAKES: All right. So we'll just make that change for the final exhibit list.

MR. FAVREAU: So what?

A.L.J. LECAKES: There's no change to the exhibit list or anything. It's just an identification on the actual exhibit list of the witness that submitted the testimony. The -- they were offered in correct sequence right now and they were marked correctly in 59, 60, 61, and 62 so nothing is changing other than the appearance of the list itself -- the exhibit list.

MR. FAVREAU: Okay. Gotcha. Thank you.

A.L.J. LECAKES: And we marked the Donald Parr affidavit as Exhibit 63. I believe you said there was just the one additional exhibit. Is that correct?

MR. NICKSON: That is correct, Your Honor.

A.L.J. LECAKES: And that's 64. Okay. Next?

MR. NICKSON: The next is company witness John Reed. Mr. Reed prepared testimony entitled

The Rebuttal Testimony of John Reed which consists of 38 pages of questions and answers. Mr. Reed also prepared testimony entitled The Supplemental Testimony of John Reed which consists of 3 pages of questions and answers and I ask that the rebuttal testimony and supplemental testimony of John Reed be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. So that would be -- well, let's mark the affidavit as Exhibit 65 and it should be in the Rebuttal Testimony folder as Reed Rebuttal Testimony.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, AFFILIATION AND BUSINESS ADDRESS.

A. My name is John Reed. I am Chairman and Chief Executive Officer ("CEO") of Concentric Energy Advisors, Inc. ("Concentric") and CE Capital, Inc. ("CE Capital") located at 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this rebuttal testimony on behalf of National Fuel Gas Distribution Corporation ("Distribution" or "the Company) in its rate case filing (Case 16-G-0257) before the New York State Public Service Commission (the "Commission").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I have more than 40 years of experience in the energy industry and have worked as an executive in, and consultant and economist to, the energy industry. Over the past 28 years, I have directed the energy consulting services of Concentric, Navigant Consulting, and Reed Consulting Group. I have served as Vice

Chairman and Co-CEO of the nation's largest publicly-traded consulting firm and as Chief Economist for the nation's largest gas utility. I have provided regulatory policy and regulatory economics support to more than 100 energy and utility clients and have provided expert testimony on regulatory, economic, and financial matters on more than 150 occasions before the Federal Energy Regulatory Commission, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada, including on matters related to mergers, divestitures, asset acquisitions, and reorganizations. As part of my work, I have developed cost of capital, capital structure, risk profile, ring-fencing and financing strategy recommendations for utilities across North America. I have also testified many times on regulatory policy issues. My educational background and prior experience, including expert testimony, is presented in more detail in Exhibit_(JR-1): Résumé and Testimony Listing.

Q. PLEASE DESCRIBE CONCENTRIC'S AND CE CAPITAL'S ACTIVITIES IN ENERGY AND UTILITY ENGAGEMENTS.

A. Concentric provides financial and economic advisory services to many energy and utility clients across North America. Our regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services, energy market assessments, market entry and exit analysis, corporate and business

unit strategy development, demand forecasting, resource planning, and energy contract negotiations. Our financial advisory activities include both buy- and sell-side merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services, and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America. CE Capital is a fully registered broker-dealer securities firm specializing in merger and acquisition activities. As CEO of CE Capital, I hold several securities licenses that cover all forms of securities and investment banking activities.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to review and respond to the direct testimony of the Department of Public Service Staff Finance Panel ("Staff" or the "Staff Finance Panel") regarding their recommendations for the imposition of "ring-fencing" provisions on Distribution. My rebuttal testimony addresses ring-fencing from a regulatory policy, purpose and precedent, and investment community perspective. The rebuttal testimony of the Company Finance Panel addresses Staff's ring-fencing proposal as it relates to the facts and circumstances specific to Distribution and its parent, National Fuel Gas Company ("NFG").

Q. AS A PRELIMINARY MATTER, PLEASE DEFINE "RING-FENCING."

A. As I discuss in more detail later in my rebuttal testimony, "ring-fencing" is a term used to refer to financial conditions (*e.g.*, securities restrictions, dividend restrictions, and capital availability covenants) and related governance conditions (*e.g.*, restrictions on the ability to pledge assets or declare bankruptcy) that are intended to financially and/or operationally isolate and protect one entity from its parent and other affiliates. In the context of utility regulation, ring-fencing is a tool used in the context of utility mergers, acquisitions or reorganizations. Ring-fencing encompasses a range of measures; the specific measures employed, if any, vary by utility transaction.

Q. WHAT SPECIFIC EXPERIENCE DO YOU HAVE IN REVIEWING OR DEVELOPING RING-FENCING PROTECTIONS FOR PUBLIC UTILITIES?

A. This is an issue I have dealt with in many proceedings over the past 20 years. For example, I testified before the Public Utility Commission of Texas in support of ring-fencing measures that were implemented as part of Energy Future Holdings' 2007 acquisition of Oncor Electric Delivery Company. I have also had recent experience with these issues in the NextEra Energy/Hawaiian Electric, Wisconsin Energy/Integrys, Fortis/UNS, Northeast Utilities/NStar and Macquarie/Cleco transactions. As part of this work, I have reviewed ring-fencing provisions in many utility mergers over the past 20 years.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section II summarizes my understanding of the Staff Finance Panel's ring-fencing proposals and my key conclusions in response to that testimony. In Section III, I address the Staff Finance Panel's testimony purporting a need for and precedent supporting the imposition of new ring-fencing measures in this rate case proceeding. Section IV addresses the Staff Finance Panel's testimony regarding the views of Moody's Investors Service ("Moody's") and Standard & Poor's ("S&P") (collectively, with Fitch Ratings, referred to as the "Credit Rating Agencies") regarding ring-fencing and utility risks. In Section V, I provide my assessment of the specific ring-fencing measures proposed by the Staff Finance Panel. Finally, Section VI summarizes the conclusions and recommendations of this rebuttal testimony.

II. SUMMARY OF THE STAFF FINANCE PANEL'S TESTIMONY

Q. WHAT IS YOUR UNDERSTANDING OF THE PURPOSE OF THE STAFF FINANCE PANEL'S TESTIMONY?

A. The Staff Finance Panel describes the purpose of their testimony as to "establish the fair rate of return (ROR) that will be used to determine the revenue requirement for National Fuel Gas Distribution Corporation…" The Staff Finance Panel goes on to note that "estimating the ROR requires an estimation of

the proper capital structure" and assert that their recommendation "provides the Company with continued access to reasonably-priced capital."[1]

Q. PLEASE BRIEFLY SUMMARIZE THE STAFF FINANCE PANEL'S RING-FENCING RELATED TESTIMONY.

A. The Staff Finance Panel introduces ring-fencing in the context of establishing the appropriate capital structure for ratemaking purposes and opposes the 48% utility stand-alone equity ratio requested by Distribution. The Staff Finance Panel argues that NFG's corporate common equity ratio, which it calculates as 42.3%, should be used in establishing Distribution's rate of return unless "suitable ring-fencing" is in place.[2] The Staff Finance Panel testifies that NFG's non-regulated businesses, in particular its exploration and production business ("E&P"), expose NFG's utility operations, including Distribution, to risk. Staff also provides its interpretation of the hypothetical impacts on Distribution of the impairments of E&P's assets, the recent one notch downgrade by Moody's of NFG's credit rating from Baa2 to Baa3, and the debt covenant restrictions under NFG's 1974 indenture.[3] The Staff Finance Panel asserts that "it is essential that additional, strong ring-fencing provisions be instituted,"[4] arguing that the majority of other New York operating companies have adopted ring-fencing measures, and

[1] Staff Finance Panel Testimony, at 5-6.
[2] *Ibid*., at 16-17.
[3] *Ibid*., at 25-29.
[4] *Ibid*., at 33.

recommends the imposition of six specific ring-fencing measures on NFG.[5] The Staff Finance Panel concludes its ring-fencing testimony stating that if NFG "implements our recommended ring-fencing provisions, and they are recognized by S&P and Moody's, then we would view Distribution's assets as properly insulated from the parent and a higher common equity ratio, perhaps one in the 48.0% range, should be considered in the next rate proceeding."[6]

Q. PLEASE IDENTIFY THE SPECIFIC RING-FENCING MEASURES PROPOSED BY THE STAFF FINANCE PANEL.

A. The Staff Finance Panel proposes that six specific ring-fencing measures be imposed in this proceeding:

1. Distribution be prohibited from paying dividends to NFG if its average common equity ratio for the trailing 12 months prior to the dividend payment is more than 200 basis points below the common equity ratio used in setting rates.
2. Distribution should be required to issue its own long-term debt.
3. NFG should pursue obtaining individual credit ratings from Moody's and S&P for Distribution.
4. If Distribution is unable to obtain its own credit rating and NFG is downgraded from either the current S&P 'BBB' rating or the Moody's 'Baa3' rating, the interest rate for Distribution in subsequent rate filings should match that of Staff's proxy group, for "BBB+" utilities.
5. Distribution should be required to create a special class of preferred stock, to be held by a trustee approved by the Commission, which shall be referred to as the "golden share." The holder of the "golden share" would be independent of the holding company and its affiliates, and could prevent a bankruptcy of the parent, or any of its affiliates, from triggering a voluntary bankruptcy of

[5] *Ibid*., at 36-38.
[6] *Ibid*., at 39.

Distribution. The holder of the "golden share" would exercise the voting right for the protection of the interests of New York ratepayers.

6. NFG's general counsel should issue a non-consolidation letter that will be filed with the Commission to demonstrate the implementation of the ring-fencing provisions and the legal and credit separation of Distribution from its parent and affiliates.[7]

Q. WHAT IS YOUR OVERALL REACTION TO THE STAFF FINANCE PANEL'S RING-FENCING TESTIMONY?

A. The Staff Finance Panel's concerns regarding the financial stability of NFG are misplaced, and that the imposition of their proposed ring-fencing measures in this rate proceeding for Distribution is unnecessary. There are simply no facts supporting the Staff Finance Panel's unprecedented and unwarranted position, no plausible need for the imposition of ring-fencing measures in this proceeding, and no reasonable public policy reason to adopt their views or their recommendations regarding ring-fencing.

The Staff Finance Panel attempts to paint a dark picture of NFG as a risky holding company supporting its declining non-regulated businesses on the back of its utility operations. As discussed in more detail by the Company Finance Panel, and later in this testimony, there are no facts to support Staff's view. The Staff Finance Panel's recommendations are significant, and in some cases extreme. The forms of ring-fencing Staff would impose through this rate case to protect

[7] *Ibid*. at 37-38.

Distribution from these hypothetical risks and to better position it with the Credit Rating Agencies are unnecessary, unworkable and poor public policy.

Q. TO PROVIDE CONTEXT FOR THE REMAINDER OF YOUR TESTIMONY, PLEASE SUMMARIZE THE COMPANY FINANCE PANEL'S RING-FENCING RELATED TESTIMONY AND CONCLUSIONS MOST RELEVANT TO YOUR TESTIMONY.

A. In response to the Staff Finance Panel's ring-fencing related testimony, the Company Finance Panel testifies and concludes that:

- The Company has mechanisms in place via its Money Pool arrangement to insulate Distribution from its non-rate-regulated subsidiaries.
- The impairment of E&P's assets is an accounting adjustment based on a formulaic computation required by the U.S. Securities and Exchange Commission ("SEC") that establishes a valuation based on historical oil and natural gas prices and a 10% discount rate. That valuation does not impact or consider NFG's on-going cash flow.
- The one-notch downgrade of NFG's credit rating by Moody's had no impact on either NFG's (1) embedded cost of debt reflected in its rates proposed in this rate case, or (2) the predominant credit rating that would be used from the perspective of many market participants to establish the cost of new debt NFG may issue in the future.

- Further, NFG has no plans to issue new long-term debt until April 2018. As a result, the debt covenant restrictions on the issuance of incremental long-term that are discussed in the Staff Finance Panel's testimony are expected to have no impact on NFG or Distribution, and certainly have no impact on this rate case. In addition, the debt covenant in question does not prohibit the re-financing of maturing debt, which is the stated purpose of NFG's next two debt issuances.
- NFG is not, as one might infer from the Staff Finance Panel's ring-fencing-related testimony and proposals, a company facing a threat of bankruptcy. NFG, Distribution and its other subsidiaries are, and have been, financially sound.
- To provide additional assurance of Distribution's ability to access debt in the near-term, NFG is in the process of amending the Money Pool to reserve a portion of its committed credit facility solely for the benefit of Distribution, essentially providing Distribution with a dedicated line of credit without having to incur additional costs to obtain its own credit rating.
- The ring-fencing measures proposed by the Staff Finance Panel are not only unnecessary but would also be harmful. First, the implementation of the Staff's proposed "golden share" class of stock would: (1) run counter to the Company's existing credit agreement, jeopardizing a critical component of the Company's liquidity profile; and (2) potentially violate certain covenants in

the Company's 1974 bond indenture. Second, the implementation of the proposed ring-fencing provisions would have significant costs that would need to recovered from ratepayers.

Q. PLEASE BRIEFLY SUMMARIZE YOUR RESPONSE TO, AND KEY CONCLUSIONS REGARDING, THE STAFF FINANCE PANEL'S RING-FENCING RELATED TESTIMONY.

A. As I discuss in more detail later in my rebuttal testimony:

- The purpose of this proceeding is for the Commission to set just and reasonable rates for Distribution. The Commission has the necessary authority and tools available to it within the rate case to set just and reasonable rates without imposing ring-fencing.
- In my more than 40 years in this industry, I have never seen the ring-fencing measures proposed by the Staff Finance Panel in this proceeding imposed in a rate case. Ring-fencing is a tool used in some, but not all, utility mergers, acquisitions or reorganizations. In New York, ring-fencing for electric and natural gas utilities has been implemented largely in the context of restructuring, reorganizations, and acquisitions of local utilities by international holding companies. In those cases, ring-fencing has been adopted based on the desire to provide protections appropriate to the facts and circumstances specific to those transactions, which involved

an underlying change in ownership structure and/or governance. That is not the case here.

- There has been no incremental cost to customers or other harm that needs to be addressed by the Commission in this rate case that would be solved by ring-fencing. If the cost of future debt issuances is increased due to non-utility factors, the ready remedy available to the Commission in a future rate case is simply to adjust the cost of debt for the affected issuance at that point in time.
- It would be entirely inappropriate to conclude that an accounting adjustment for E&P caused largely by the fluctuation of oil and natural gas prices should affect the ratemaking capital structure of Distribution.
- The corporate structure and financing of NFG and its subsidiaries was explicitly approved by the Commission in its Order Approving Corporate Reorganization with Conditions issued on June 21, 1974 in Case 26434.[8] It is inappropriate to seek to impose a significant change to the corporate structure and financing of NFG, a long-standing, well-functioning holding company in order to purportedly protect the customers of one of the state's

[8] Order Approving Corporate Reorganization with Conditions, Joint Petition of Iroquois Gas Corporation and Pennsylvania Gas Company for Approval to Transfer Franchises and Facilities to NFG Gas Corporation and for Approval to Transfer by Merger all remaining Assets of Iroquois Gas Corporation and Pennsylvania Gas Company to United Natural Gas Company, Case 26434, June 21, 1974.

most efficient distribution utilities from hypothetical and highly speculative future risks.

- The Staff Finance Panel misunderstands the interests of the Credit Rating Agencies. Ring-fencing is not always viewed as a positive attribute by the Credit Rating Agencies for utility holding companies. Adopting the Staff Finance Panel's ring-fencing beliefs and proposals would not result in lower rates, or be favorable for customers. In fact, it could disadvantage both NFG and Distribution.
- Adopting Staff's position has the potential to harm Distribution by increasing the regulatory risk perceived by the investment community due to the introduction of unexpected and extreme actions.
- NFG's existing practices, and the Commission's existing policies, reasonably and appropriately isolate and protect Distribution from NFG and its non-regulated subsidiaries. NFG's existing Money Pool agreement, along with a proposed modification, would provide Distribution with priority and exclusive access to near-term debt. These measures, coupled with the Commission's existing ratemaking tools more than adequately protect Distribution customers.
- I am also concerned about the appropriateness of effectively holding Distribution's allowed return on rate base as a "hostage" in Staff's attempt to use this proceeding to impose ring-fencing measures that have no place

in a rate case. These measures may be appropriate to consider in a proposed transaction, such as a merger or acquisition (including the acquisition of New York utilities by foreign entities), where the public interest is broadly considered, but are not necessary to, or appropriate for, setting just and reasonable rates in a rate proceeding.

- The Staff Finance Panel's ring-fencing proposal is neither necessary nor appropriate in this rate case and should be rejected.

III. THE STAFF FINANCE PANEL'S POSITION ON RING-FENCING

Q. WHAT TOPICS WILL YOU ADDRESS IN THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A. In this section of my rebuttal testimony, I will address the positions put forth by the Staff Finance Panel on ring-fencing overall. In particular, I address the following:

- The definition of ring-fencing;
- The role of ring-fencing in this rate case;
- When ring-fencing is appropriate;
- The use of ring-fencing in New York; and
- NFG's existing practices to isolate Distribution from its other subsidiaries.

In later sections of my rebuttal testimony I will address the Staff Finance Panel's testimony regarding the Credit Rating Agencies' view of ring-fencing and the six specific ring-fencing measures Staff recommends in this proceeding.

A. DEFINITION OF RING-FENCING

Q. EARLIER IN YOUR TESTIMONY YOU DEFINED "RING-FENCING." DOES YOUR DEFINITION OF RING-FENCING DIFFER FROM THAT PUT FORTH BY THE STAFF FINANCE PANEL?

A. Yes. An important distinction that is missing from the Staff Finance Panel's testimony is that ring-fencing is a tool that has been used in varying degrees, if at all, in utility mergers and acquisitions to address the specific risks triggered by individual utility transactions. That was the case in the mergers and acquisitions of the New York utilities discussed by the Staff Finance Panel. In a merger proceeding the Commission is asked to render findings on a proposed transaction that would create new ownership, changed operational control and/or a modified organizational structure of the utility being acquired or reorganized. In applying for approval from state regulators of a utility transaction, merging companies may proactively propose ring-fencing provisions in order to demonstrate that, post transaction, the utility and its customers will be insulated from potential financial risks associated with a new ownership structure. In some circumstances, state regulators may require the implementation of additional financial and associated governance restrictions to further insulate and protect the utility and its customers. Those merger and acquisition approval proceedings, however, are very different than a rate case such as the instant proceeding, in which the Commission is

required to establish just and reasonable rates for the utility based upon the utility's known and reasonably verifiable forecasted test period costs.

B. THE ROLE OF RING-FENCING IN THIS RATE CASE

Q. WHAT IS THE PURPOSE OF THIS RATE CASE PROCEEDING?

A. The purpose of this rate case proceeding is for the Commission to establish just and reasonable rates for Distribution.

Q. IS THE STAFF FINANCE PANEL'S RING-FENCING PROPOSAL RELEVANT TO THE COMMISSION'S ESTABLISHMENT OF JUST AND REASONABLE RATES FOR DISTRIBUTION IN THIS PROCEEDING?

A. No. The Staff Finance Panel's ring-fencing proposal has nothing to do with establishing just and reasonable rates for Distribution in this proceeding. As discussed by the Company Finance Panel, Distribution's embedded cost of debt reflected in its proposed rates were not impacted by the E&P impairment or the Moody's downgrade. The Staff Finance Panel is asking the Commission to impose ring-fencing in this rate case to purportedly address hypothetical potential future risks. The Staff Finance Panel is also asking the Commission to set rates using the parent holding company's equity ratio that reflects the very thing that Staff asserts they wish to protect customers from, *i.e.* the influence of NFG's non-regulated businesses. This is in sharp contrast to the 48 percent equity ratio that

Staff recommended in the Company's last rate case (Case 13-G-0136). This has the appearance of a being a results oriented, "heads-I-win-tails-you-lose" approach to ratemaking. In my more than 40 years in the industry, I have never seen ring-fencing like this imposed in a rate case.

Q. DOES THE COMMISSION HAVE THE NECESSARY TOOLS AVAILABLE TO IT WITHIN ITS RATE CASE AUTHORITY TO SET JUST AND REASONABLE RATES WITHOUT IMPOSING RING-FENCING?

A. Yes. New York's approach to utility ratemaking and the Commission's ability to adjust Distribution's allowed costs when warranted by the facts and circumstances provide the Commission with all the tools it needs. If the Commission were to conclude that Distribution's cost of debt was unreasonable, which has certainly not been shown in this case, the ready remedy available to the Commission is to simply adjust Distribution's weighted average cost of debt. By doing so, customers would be held harmless for the costs that were deemed to be unreasonable.

In addition, by using a utility capital structure for establishing the rate of return, the Commission insulates Distribution and its customers from the capital structure of its holding company parent that has had an equity ratio as high as 63.5% and has averaged 56.7% over the past five years. It would be entirely inappropriate to

allow an accounting adjustment (*i.e.*, an impairment charge) caused largely by the recent fluctuation in oil and natural gas prices affecting E&P to influence the allowed capital structure of Distribution. In fact, avoiding that is part of the objective of the stand-alone approach to utility ratemaking. At a minimum, it is inconsistent for the Staff Finance Panel to argue on the one hand that Distribution should be specifically isolated from NFG and its other subsidiaries, but on the other hand if it is not, then adopt NFG's corporate capital structure; a capital structure that coincidentally contains a lower equity ratio than any natural gas utility equity ratio authorized by the Commission over the last 10 years, and all but one natural gas utility over the last 20 years.[9] As discussed in the direct and rebuttal testimonies of Ann Bulkley, the 48% equity ratio requested by the Company conforms to the Commission's capital structure decisions over the last five years and should be used to establish the allowed rate or return in this proceeding.

C. WHEN RING-FENCING IS APPROPRIATE

Q. PUTTING ASIDE WHETHER IT IS RELEVANT TO ESTABLISHING JUST AND REASONABLE RATES IN THIS RATE CASE, IS THERE A GENERAL THEME TO WHEN RING-FENCING PROTECTIONS SHOULD BE EMPLOYED FOR PUBLIC UTILITIES IN THE ENERGY

[9] Source: Regulatory Research Associates Past Rate Case History, accessed September 9, 2016.

INDUSTRY AND DO THOSE CIRCUMSTANCES EXIST HERE FOR DISTRIBUTION?

A. Yes, there is a general theme, however those circumstances do not exist here. Isolation of an electric or gas utility subsidiary through ring-fencing began with foreign utilities acquiring U.S. utilities, which was the circumstance in New York, and the emergence of private equity companies acquiring public utilities in transactions that involved unprecedented levels of debt at the holding company level. Neither of those situations exists with regard to Distribution. Under the circumstances in which it was perceived that the utility was being acquired by a riskier parent, regulators sought to protect customers from unfamiliar business models or highly-leveraged capital structures. Regulators also sought to ensure that a utility's operations under such circumstances would be managed on a "stand-alone" basis. This was understandable in situations where the new owners did not bring operational expertise to the management of the acquired company, or when extraordinarily high levels of holding company debt were used to finance a utility acquisition. These ring-fencing provisions were often derived from credit enhancement techniques that had previously been used to issue securitized debt for recovery of stranded costs arising in industry restructuring. That is certainly not the case here with NFG and Distribution.

Q. IS RING-FENCING NECESSARY FOR ALL UTILITIES THAT HAVE A HOLDING COMPANY PARENT AND NON-REGULATED AFFILIATES?

A. No. Ring-fencing is not a universal benefit or risk reduction mechanism for all utilities that are part of a holding company structure. The Staff Finance Panel's ring-fencing testimony and proposal appear to have been triggered by the impairment of E&P. The impairment is not the result of imprudent or irresponsible investments or financial management of NFG, it is simply an accounting entry resulting from rules put forth by the SEC and a cyclical change in oil and natural gas prices that has no impact on NFG's on-going cash flow. The Staff Finance Panel's assertion that this accounting entry requires the imposition of massive ring-fencing and bankruptcy protections is a misunderstanding and overreaction to the facts. The Staff Finance Panel's proposed ring-fencing measures are truly a solution in search of a problem. Staff has not identified any problem where the ratepayer has been harmed due to NFG's financial policies, nor is there a hypothetical future problem that may not be addressed with the ratemaking tools already available to the Commission. As further support, I also note the Commission has consistently approved the debt financing approach employed by NFG for Distribution for many years without requiring ring-fencing provisions.[10]

[10] *See, e.g.*, Order Authorizing Issuance of Securities, Case 14-G-0228, November 14, 2014.

D. RING-FENCING IN NEW YORK

Q. PLEASE DESCRIBE THE CIRCUMSTANCES THAT LED TO THE ADOPTION OF VARIOUS RING-FENCING MEASURES AT OTHER NEW YORK UTILITIES.

A. The main driver behind the initial adoption of ring-fencing for other New York operating companies has been primarily the merger of utilities or acquisition of New York utilities by foreign buyers, as shown in the table below.

Utility(ies)	**Ring-Fencing Driver**	**Case No.**
Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities Inc.	Merger or acquisition	98-M-0961
CH Energy Group Inc.	Merger or acquisition	12-M-0192
New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation	Merger or acquisition	07-M-0906
Niagara Mohawk Power Corporation	Merger or acquisition; petition to issue $2 billion of long-term indebtedness and enter into derivative hedging instruments	01-M-0075 06-M-0878 08-E-0827 08-M-1352 10-E-0050
KeySpan Energy Delivery Long Island and KeySpan Energy Delivery New York	Merger or acquisition	06-M-0878

Q. SHOULD THE COMMISSION BE SWAYED BY THE STAFF FINANCE PANEL'S TESTIMONY THAT THE MAJORITY OF NEW YORK OPERATING COMPANIES HAVE ADOPTED RING-FENCING PROTECTIONS SIMILAR TO THOSE PROPOSED BY STAFF HERE?

A. No. The Staff Finance Panel simply makes a sweeping conclusion that because some major New York operating companies have ring-fencing, NFG should as well. The Staff Finance Panel completely ignores the events, facts and circumstances that led to the initial adoption of ring-fencing by the other New York operating companies to which it refers. In Exhibit FP-11 the Staff Finance Panel identifies other New York operating companies and summarizes its understanding of the ring-fencing measures put in place for those companies. What Staff neglects to say is that the events that triggered the origination of the ring-fencing provisions for those companies (provisions that Staff is seeking to impose here) were issues stemming from mergers and changes in ownership and operational control of the New York utility. The Staff also neglects to acknowledge that the specific ring-fencing measures in place for each company are not the same, and furthermore that they differ based upon the facts and circumstances at the time the Commission rendered its orders putting these measures in place. For example, only some of the transactions included provisions related to the "golden share" and non-consolidation opinions.

Q. IN WHAT CIRCUMSTANCES HAS THE COMMISSION MANDATED A "GOLDEN SHARE" PROVISION FOR NEW YORK UTILITIES?

A. The "golden share" provisions that Staff cites in Exhibit FP-11 for the utilities were approved by the Commission in the context of the acquisition of a New

York utility by an international holding company, driven by concerns over holding companies using a highly-leveraged financial structure with large amounts of goodwill as well as additional concerns regarding financial transparency, complex corporate structures, and uncertain business models. The first New York utilities cited in Staff's Exhibit FP-11 for which the Commission implemented a "golden share" provision were KeySpan Energy Delivery Long Island ("KEDLI") and KeySpan Energy Delivery New York ("KEDNY") in its Order approving the acquisition of KeySpan Corporation by the multinational utility holding company National Grid plc ("National Grid").[11]

In that same Decision, the Commission ruled that similar financial protections, including the "golden share" provision, would also subsequently be applied to Niagara Mohawk Power Corporation ("NMPC") out of a concern that the same financial risks being posed to KEDLI and KEDLI by the National Grid acquisition also applied to NMPC given that many of these protections and the "golden share" provisions were not mandated following National Grid's earlier acquisition of NMPC.

The Commission applied similar "golden share" provisions to New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation

[11] *See*, Abbreviated Order Authorizing Acquisition Subject to Conditions and Making Some Revenue Requirement Determinations for KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island, Case 06-M-0878, August 23, 2007, at 12 and Order Authorizing Acquisition Subject to Conditions and Making Some Revenue Requirement Determinations for KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island, Case 06-M-0878, September 17, 2007.

following their acquisition by Iberdrola, S.A.,[12] and also in its approval of the acquisition of CH Energy Group, Inc. by Fortis, Inc.[13] Similarly, in those cases the "golden share" requirement was driven by concerns of international holding companies with complex corporate structures and large amounts of goodwill.

Q. WHY IS THAT INFORMATION SIGNIFICANT FOR THIS CASE?

A. The Commission has never required a "golden share" for a utility that was owned by a domestic holding company. Thus, Staff's proposal here is inconsistent with past Commission policy and practice.

Q. HAS STAFF RECOMMENDED A "GOLDEN SHARE" FOR OTHER NEW YORK UTILITIES THAT ARE OWNED BY A DOMESTIC HOLDING COMPANY?

A. Yes. Staff is currently recommending in the Consolidated Edison of New York ("Con Edison") rate case that Con Edison issue a "golden share" and provide a non-consolidation opinion.[14] While the case is yet to be decided, Con Edison vigorously opposed Staff's ring-fencing recommendations in rebuttal testimony.

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[12] *See*, Order Authorizing Acquisition Subject to Conditions, Case 07-M-0906, September 9, 2008, at 43-49.
[13] *See*, Order Authorizing Acquisition, Case 12-M-0192, June 26, 2013, at 42.
[14] Staff Finance Panel Testimony, Cases 16-E-0060 and 16-G-0061, at 28-29.

Q. IS THIS RATE CASE SIMILAR TO THOSE INSTANCES IN WHICH RING-FENCING WAS IMPLEMENTED FOR OTHER NEW YORK UTILITIES?

A. No, not at all. First, this proceeding is a rate case in which Distribution is entitled to have rates set that are just and reasonable, including a reasonable opportunity to earn a fair return. Staff's proposal does not meet that standard. The key distinctions between this proceeding and the cases in which ring-fencing was implemented for other New York utilities is that, in those merger and reorganization cases the applicants needed to show that proposed transactions were in the public interest, and the Commission was faced with something new and different from a financial and governance perspective: a new utility owner, a new corporate structure, and/or a new and uncertain business model. Importantly, none of those circumstances exists in this proceeding. Rather, as described herein, the triggering events for Staff's proposal were a series of accounting entries that had no impact on the cash flow or substantive credit profile of Distribution, and a one-notch downgrade of NFG by Moody's that had no impact on the debt costs embedded in Distribution's revenue requirement. As such, the fact that ring-fencing provisions may have been implemented at other New York utilities seeking approvals of transactions is irrelevant to this proceeding in that those provisions were put in place in the context of facts, circumstances, and issues that don't exist for Distribution.

E. NFG'S EXISTING PRACTICES

Q. ARE THE PRACTICES NFG HAS IN PLACE TODAY TO INSULATE DISTRIBUTION FROM THE ACTIVITIES OF NFG AND ITS OTHER SUBSIDIARIES REASONABLE AND APPROPRIATE?

A. Yes. As discussed in more detail by the Company Finance Panel, the company currently has mechanisms in place via its Money Pool that insulate Distribution while still affording it the benefits of being part of the NFG family. In addition, NFG is in the process of amending the Money Pool to reserve a portion of its committed credit facility solely for the benefit of Distribution, essentially providing Distribution with a dedicated line of credit without having to incur additional costs to obtain its own credit rating or credit facility. The Company also employs other practices that insulate Distribution, including: (1) imposition of limits on subsidiary borrowing from parties other than NFG provide a "check-and-balance" that no subsidiary may engage in borrowing that deviates from NFG's approach to prudent fiscal management; and (2) Distribution maintains separate bank accounts and does not comingle its funds with its affiliates, providing clear separation of funds.[15] Lastly, Distribution's cost allocation practices and affiliate transaction rules provide further protective measures.

[15] NFG Response to Department of Public Service Request for Information DPS-181, Case 16-G-0257.

Q. IS THE STAFF FINANCE PANEL'S PROPOSED RING-FENCING NECESSARY AND WOULD IT ENHANCE THE COMPANY'S EXISTING PRACTICES?

A. No. It is entirely inappropriate to impose a significant change to the corporate structure and financing of NFG, a long-standing, well-functioning holding company, in order to protect the customers of one of the state's most efficient distribution utilities from hypothetical and highly speculative future risks. Staff's proposal is not a necessary or appropriate approach to establish just and reasonable rates; the Commission already has the necessary tools at its disposal without imposing the costs, disruption and poor regulatory policy of ring-fencing through a rate case. In addition, there is no universal benefit to be derived from ring-fencing. Ring-fencing as practiced in New York has been the product of the events (*i.e.*, mergers and acquisitions), and facts and circumstances surrounding those events – it is not a "one-size-fits-all" solution. The Staff Finance Panel's ring-fencing testimony and proposal are truly a solution in search of a problem, and here, that problem does not exist.

IV. <u>CREDIT RATING AGENCIES AND RING-FENCING</u>

Q. DOES STAFF DISCUSS THE CREDIT RATING AGENCIES' VIEWS ON RING-FENCING?

A. Yes. The Staff Finance Panel points to comments by Moody's regarding how ring-fencing can create separateness between a utility and its parent. However,

missing from the Staff Finance Panel's assessment is any analysis of how the Credit Rating Agencies might view the imposition of ring-fencing in *this* case. Because ring-fencing provisions are typically proposed by merging utilities in order to provide assurance to regulators regarding the lack of harm to ratepayers caused by the merger, such ring-fencing provisions tend to be viewed favorably by the Credit Rating Agencies if they are seen as providing protection from the financial risks of a significantly lower-rated parent and/or financial investor. However, if in this case the restrictive ring-fencing provisions proposed by the Staff Finance Panel were to be imposed in the context of a rate case, the increase in the regulatory risk perceived by the investment community would offset (if not outweigh) any arguable benefits of the ring-fencing. Simply put, creating a substantial disruption in corporate financing plans, higher costs to retire and refinance existing debt, and confiscatory return levels to insert protections against potential future financing risks would be seen by any rational investor as being detrimental to a utility's financial integrity.

Q. WHAT FACTORS DID YOU CONSIDER IN COMING TO THE OPINION THAT THE IMPOSITION OF STRICT RING-FENCING PROVISIONS IN A RATE CASE WOULD *INCREASE* THE REGULATORY RISK PERCEIVED BY THE INVESTMENT COMMUNITY?

A. The main factor I considered was that the imposition of strict ring-fencing provisions in a rate case would be a clear departure from Commission standard practice that, if coupled with a capital structure that contains less equity than any utility capital structure authorized by the Commission for a natural gas utility in the last 10 years, and the second lowest in 20 years, as discussed above, would significantly increase the perceived risk related to the regulatory framework in New York within which Distribution operates.

As noted in the Staff Financial Panel's testimony (at page 24), 50% of Moody's ratings evaluations of utilities is based on the supportiveness of the regulatory environment in which a utility operates. Specifically, Moody's credit evaluation is based 25% on the regulatory framework, and 25% on a utility's ability to recover costs and earn its return, which is derived in large part from its rate structure. Subsumed in Moody's credit evaluation of the regulatory framework is the rating sub-factor of "consistency and predictability of regulation." In describing why the regulatory framework matters to its credit evaluations, Moody's states:

> For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the

> predictability and consistency of decision-making provided by that foundation.[16]

Similarly, S&P states:

> The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.[17]

S&P goes on to state that a lack of predictability and consistency is reflective of a weak qualifier in terms of S&P's "preliminary regulatory advantage assessment."[18]

In my opinion, the abrupt and unwarranted imposition of the Staff Finance Panel's proposed ring-fencing measures in the context of a rate case would be a clear display of regulatory unpredictability and inconsistency.

Q. NFG IS CURRENTLY RATED BBB BY S&P AND BAA3 BY MOODY'S. ARE THOSE INVESTMENT GRADE RATINGS?

A. Yes, they are. Notwithstanding the downgrade of NFG's credit rating by Moody's, NFG remains an investment grade company. From a ratings quality perspective, the key demarcation is that between investments grade issuers (*i.e.*, BBB-/Baa3 and above) and sub-investment grade issuers (*i.e.*, BB+/Ba1 and below). Many institutional investors have requirements to invest only in bonds

[16] Moody's Investor Service, "Regulated Electric and Gas Utilities," December 23, 2013, at 9.
[17] Standard & Poor's Ratings Services, "Key Credit Factors for the Regulated Utilities Industry," November 19, 2013, at 6.
[18] *Ibid*., at 8.

that are investment grade or above. While NFG is "split rated" (*i.e.*, has different ratings from S&P and Moody's), as the Company Finance Panel states, it still maintains a predominant rating of BBB as viewed by many investors.

Thus, in the context of this rate proceeding, in which the revenue requirement and test year assume investment-grade bond ratings in the embedded cost of debt, there is no reasonable basis on which to impose governance or financing restrictions that are designed to isolate the utility from a parent or affiliate that is not creditworthy.

Q. BEYOND CREDIT RATINGS, ARE THERE OTHER FACTORS THAT WOULD INDICATE RING-FENCING MIGHT BE APPROPRIATE IN THIS CASE?

A. None that I am aware of. For instance, there is no evidence of harvesting capital on the part of NFG or its non-utility affiliates, under-investing in the utility, or service quality deterioration, nor is the Staff Finance Panel suggesting that such circumstances exist.

V. SPECIFIC RING-FENCING MEASURES PROPOSED BY THE STAFF FINANCE PANEL

Q. WHAT TOPICS WILL YOU ADDRESS IN THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A. Putting aside the policy implications of the Staff Finance Panel's ring-fencing positions and proposals, as well as the question of whether ring-fencing as

described by Staff can be imposed in the context of a rate case, there are significant practical issues that would be created by the Staff Finance Panel's proposed ring-fencing measures. I address these practical considerations in this section of my rebuttal testimony.

Q. EARLIER IN YOUR TESTIMONY YOU IDENTIFIED THE SPECIFIC RING-FENCING MEASURES PROPOSED BY THE STAFF FINANCE PANEL. FOR CONVENIENCE, PLEASE LIST THEM AGAIN.

A. The Staff Finance Panel proposes that the following six specific ring-fencing measures be imposed in this proceeding.

1. Distribution be prohibited from paying dividends to NFG if its average common equity ratio for the trailing 12 months prior to the dividend payment is more than 200 basis points below the common equity ratio used in setting rates.
2. Distribution should be required to issue its own long-term debt.
3. NFG should pursue obtaining individual credit ratings from Moody's and S&P for Distribution.
4. If Distribution is unable to obtain its own credit rating and NFG is downgraded from either the current S&P 'BBB' rating or the Moody's 'Baa3' rating, the interest rate for Distribution in subsequent rate filings should match that of Staff's proxy group, for "BBB+" utilities.
5. Distribution should be required to create a special class of preferred stock, to be held by a trustee approved by the Commission, which shall be referred to as the "golden share." The holder of the "golden share" would be independent of the holding company and its affiliates, and could prevent a bankruptcy of the parent, or any of its affiliates, from triggering a voluntary bankruptcy of Distribution. The holder of the "golden share" would exercise the voting right for the protection of the interests of New York ratepayers.
6. NFG's general counsel should issue a non-consolidation letter that will be filed with the Commission to demonstrate the implementation of the ring-

fencing provisions and the legal and credit separation of Distribution from its parent and affiliates.[19]

Q. PLEASE DESCRIBE THE PRACTICAL ISSUES THAT WOULD BE CREATED BY THE STAFF FINANCE PANEL'S PROPOSED RING-FENCING MEASURES.

A. The Staff Finance Panel's proposed ring-fencing measures would create a veritable Rubik's Cube of cascading issues. As the Company Finance Panel testifies, the proposed measures would potentially require modifications to, or possibly the elimination, of NFG's existing 1974 indenture. In addition to the costs associated with modifying NFG's indenture, there are the significant costs that would be incurred to register Distribution with the SEC and obtain ratings from the Credit Rating Agencies. The initial upfront and ongoing costs for compliance and required SEC filings would likely be substantial. All of those costs would be the responsibility of Distribution ratepayers. Further, as discussed by the Company Finance Panel, there are no plans to issue new debt during the rate year and Distribution's need for new debt after the rate year is limited. Assuming *arguendo* that Distribution could borrow at a lower rate than NFG, there is no near-term opportunity to realize interest rate savings yet there are significant costs. In addition, any short-term borrowing needs Distribution may have are more than satisfied by the Money Pool.

[19] Staff Finance Panel Testimony, at 37-38.

Q. HYPOTHETICALLY, IF DISTRIBUTION WERE ABLE TO ISSUE ITS OWN DEBT UNDER A HIGHER CREDIT RATING THAN ITS PARENT WOULD THAT TRANSLATE INTO BETTER TERMS AND SAVINGS TO CUSTOMERS?

A. Not necessarily. In addition to credit ratings, access to financial markets on favorable terms is also driven by the size, amount, frequency and timing of issuances, and the relationships the borrower has with financial institutions. All of those considerations favor issuance of securities at the consolidated level. Under the Staff Finance Panel's ring-fencing proposal, any such benefits provided to Distribution by NFG's structure and consolidated approach to financing would be lost.

Q. ARE PRACTICAL CONSIDERATIONS RAISED BY THE STAFF FINANCE PANEL'S ALTERNATIVE RECOMMENDATION THAT IF DISTRIBUTION IS UNABLE TO GET ITS OWN CREDIT RATING, AND NFG IS DOWNGRADED, THEN DISTRIBUTION'S INTEREST COST IN SUBSEQUENT RATE CASES SHOULD "MATCH" STAFF'S RECOMMENDED PROXY GROUP?

A. Yes. If the cost of a future debt issuance is increased due to non-utility factors, and the Commission concludes that Distribution's cost of debt is unreasonable, the Commission may simply adjust the cost of that debt issuance in the

Company's next rate case and reflect that adjusted cost in Distribution's weighted average cost of debt. A proxy credit rating and cost of debt regardless of the utility's circumstances for all debt, embedded and incremental, is unreasonable and could be confiscatory.

Q. WHAT COMMENT DO YOU HAVE REGARDING THE STAFF FINANCIAL PANEL'S PROPOSED REQUIREMENT FOR A NON-CONSOLIDATION LETTER?

A. First, a non-consolidation opinion is only relevant to avoiding an inclusion of the utility subsidiary in a parent's bankruptcy filing. Such an opinion would require complete separation of capital sources, which cannot be accomplished without incurring substantial incremental costs. Second, non-consolidation opinions are typically very extensive opinions building upon a multi-layered assessment of the various financial and legal separations of a subsidiary and its parent. Finally, as described by the Company Finance Panel, NFG is an investment grade issuer with sufficient credit that is not in threat of bankruptcy.

Q. WHAT IS YOUR REACTION TO THE STAFF FINANCIAL PANEL'S PROPOSED CREATION OF A "GOLDEN SHARE"?

A. This is among the most extreme forms of ring-fencing proposed by Staff and has nothing to do with capital structure or establishing just and reasonable rates. Putting aside the fact that Staff's proposal would potentially require a

modification to, or possible elimination of, NFG's 1974 indenture and restrictions in its corporate governance, the costs of which would be borne by ratepayers, the facts and circumstances of this rate case and NFG are dissimilar to those of the merger cases I discussed above in which the Commission adopted the implementation of a "golden share."

Q. WHAT COMMENT DO YOU HAVE REGARDING THE STAFF FINANCIAL PANEL'S PROPOSED DIVIDEND RESTRICTIONS?

A. This is another example of a restriction that is ill-defined, not based on the facts of this case and unnecessary. The legitimate purpose of a dividend restriction is to ensure that the utility has sufficient cash to invest in its operations. There is absolutely no evidence of any underinvestment by Distribution in its system. As discussed in the direct testimony of Mr. House, Distribution continues to provide its customers with safe and reliable service through a continued, and well-funded system modernization program. In addition, the direct testimony submitted by Mr. Meinl in this case discussed the fact that Distribution is among the most efficient utilities in the State. Given these circumstances, it is counterproductive and extremely poor regulatory policy to respond to that fact by imposing an unnecessary dividend restriction.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. IS ADDITIONAL RING-FENCING AS ASSERTED BY THE STAFF FINANCE PANEL NECESSARY AND APPROPRIATE FOR NFG AND DISTRIBUTION?

A. No. As described herein and in the Company Finance Panel testimony, NFG is an investment grade entity with sufficient credit facilities in place. Staff's concerns, and its proposed remedies, are misplaced and are a "solution in search of a problem." In addition, NFG's existing practices, and the Commission's existing policies, reasonably and appropriately isolate and protect Distribution from NFG and its non-regulated subsidiaries.

Q. IS IT COMMON FOR REGULATORS TO IMPOSE RESTRICTIVE RING-FENCING PROVISIONS IN A RATE CASE?

A. No. In my 40 years in the industry I have never seen an extreme proposal such as Staff's adopted or otherwise imposed by a regulatory commission in a rate case.

Q. WILL IMPOSING STAFF'S RING-FENCING REQUIREMENTS THROUGH THIS RATE CASE BE FAVORABLY RECEIVED BY THE RATING AGENCIES AS SUGGESTED BY THE STAFF FINANCE PANEL?

A. No, I don't believe so. As described in my rebuttal testimony, the consistency and predictability of the regulatory environment is a key factor used in risk

assessments by the Credit Rating Agencies. In my opinion, imposition of the Staff Finance Panel's ring-fencing proposal would be inconsistent with the Commission's established practices and introduce a significant element of regulatory risk from the investor's perspective.

Q. SHOULD THE STAFF FINANCE PANEL'S SPECIFIC PROPOSED RING-FENCING MEASURES BE ADOPTED IN THIS PROCEEDING?

A. No. As I have discussed herein, the Staff Finance Panel's ring-fencing proposal is neither necessary nor appropriate in this rate case and should be rejected.

Q. IN LIEU OF THE IMPOSITION OF THESE RING-FENCING MEASURES, SHOULD NFG'S CORPORATE EQUITY RATIO, E.G., 42.3%, BE USED IN ESTABLISHING THE RETURN ON RATE BASE?

A. No. As previously described, I am concerned about the appropriateness of using Distribution's allowed return as effectively a "hostage" in Staff's attempt to use a rate case to impose ring-fencing measures. It is also in sharp contrast to the 48 percent equity ratio that Staff recommended in the Company's last rate case based primarily on Staff's position that it was an appropriate equity ratio for a gas or electric utility in New York.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

A.L.J. LECAKES: Were there exhibits attached to Mr. Reed's rebuttal testimony?

MR. NICKSON: Yes, there was one exhibit JR1.

A.L.J. LECAKES: Okay. That will be marked as Exhibit 66 and were there exhibits attached to the supplemental testimony?

MR. NICKSON: No, Your Honor.

A.L.J. LECAKES: Okay. In addition to the rebuttal testimony that was just put into the record, we will put in the -- this would be the folder for the 9/30 -- no, no, no. Yes, the 9/30/2016 company supplemental testimony and that would be Reed Supplemental Testimony at that point in the record.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, AFFILIATION AND BUSINESS ADDRESS.

A. My name is John Reed. I am Chairman and Chief Executive Officer ("CEO") of Concentric Energy Advisors, Inc. ("Concentric") and CE Capital, Inc. ("CE Capital") located at 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. DID YOU PROVIDE REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, I did.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to respond to the supplemental testimony of the Department of Public Service Staff Finance Panel ("Staff" or the "Staff Finance Panel") regarding the "ring-fencing" provisions Staff has recommended in this proceeding for National Fuel Gas Distribution Corporation ("Distribution" or "the Company"). I also offer my perspective on the Staff Finance Panel's misinterpretation of the importance of capital structure to the credit ratings agencies' analysis of debt issuing companies.

Q. THE STAFF FINANCE PANEL, AT PAGES 1 THROUGH 3, DISCUSSES THE "ADEQUACY" OF NFG'S CAPITAL STRUCTURE, AND OFFERS AN EXHIBIT PURPORTING TO SHOW THAT MOODY'S IS "MUCH

ATTUNED TO THE DEGREE OF LEVERAGE" A COMPANY HAS. WHAT IS YOUR RESPONSE?

A. Staff has misinterpreted Moody's analysis and incorrectly inferred that Moody's statements equate to reliance on book debt and equity ratios as important credit metrics. Importantly, in Exhibit__(FP-24) (*i.e.*, the Moody's report cited by the Staff Finance Panel in its supplemental testimony), Moody's defines leverage as the ratio of debt to EBITDA, not the ratio of debt to equity. Moody's also focuses on cash flow and its ability to cover debt service. Notably (and unsurprisingly), the Moody's report cited by Staff is completely devoid of any discussion of the debt-to-equity ratio. This distinction between "leverage" and book debt and equity ratios is quite important in NFG's recent circumstances. Impairment charges reduce a company's book equity ratio, but do not have any effect on "leverage" as Moody's uses that term, or cash flow. As such, the Staff Finance Panel's assertion that capital structure is an emphasized metric in the credit rating agencies' evaluations is misplaced.

Q. WHILE A COMPANY'S ACTUAL BOOK CAPITAL STRUCTURE IS NOT A POINT OF EMPHASIS IN CREDIT RATINGS EVALUATIONS, IS THE CAPITAL STRUCTURE AUTHORIZED IN RATE PROCEEDINGS IMPORTANT FROM AN INVESTOR'S PERSPECTIVE?

A. Yes, it is. In fact, the third exhibit provided by the Staff Finance Panel with its supplemental testimony (*i.e.*, Exhibit__(FP-26), the Regulatory Research Associates' ("RRA's") "State Regulatory Evaluations" report) supports that conclusion. Specifically, RRA states (at page 4, emphasis added):

> [I]n the context of a rate case, a utility may be authorized a relatively high ROE, but factors, *e.g.*, ***capital structure changes***, the age or 'staleness' of the test period, rate base and expense disallowances, the manner in which the commission chooses to calculate test year revenue, and other adjustments, may render it unlikely that the company will earn the authorized return on a financial basis. Hence, the overall decision may be negative from an investor viewpoint, even though the authorized ROE is equal to or above the average.

The investment community places heavy weight on a utility's regulatory environment and whether it is supportive of financial strength and the abrupt and unwarranted imposition of the Staff Finance Panel's proposed ring-fencing measures in the context of a rate case would be seen as an unsupportive regulatory initiative.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

A.L.J. LECAKES: Next witness?

MR. NICKSON: The next witness is James A. Rizzo. Mr. Rizzo prepared testimony entitled The Direct Testimony of James A. Rizzo which consists of 19 pages of questions and answers. Mr. Rizzo also prepared testimony entitled The Rebuttal Testimony of James A. Rizzo which consists of 10 pages of questions and answer. I ask that the direct and rebuttal testimony of Mr. Rizzo be incorporated into the record as if given orally today.

A.L.J. LECAKES: So granted. The first file should be Rizzo Direct Testimony in the company Direct Testimony file and the second one should be Rizzo Rebuttal Testimony in the company Rebuttal Testimony. The affidavit will be marked as Exhibit 67.

DIRECT TESTIMONY OF JAMES A. RIZZO

1 Q. State your name and business address.

2 A. My name is James A. Rizzo, and my business address is 6363
3 Main Street, Williamsville, New York 14221.

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

5 A. I am employed by National Fuel Gas Distribution Corporation
6 ("Distribution" or the "Company") as General Manager of the Tax
7 Department.

8 Q. State briefly your educational and professional experience.

9 A. I graduated from State University of New York at Buffalo in 1990
10 with a Bachelor of Science Degree in Accounting. I was certified by
11 New York State as a Certified Public Accountant in 1993. Between
12 1990-2006 I worked for various public accounting firms including
13 ten years with PricewaterhouseCoopers. In 2006, I became Tax
14 Director at Greatbatch, Inc. In 2012, I was hired by Distribution as
15 General Manager of the Tax Department.

16 Q. What are your current duties and responsibilities?

17 A. I have the overall responsibility for managing the daily operations of
18 the Tax Department. Among my responsibilities are the timely filing
19 and payment of income tax, property tax, and sales and use tax. I
20 am also responsible for the proper and accurate reporting of

1 income taxes in Forms 10-Q and 10-K filed with the U.S. Securities
2 and Exchange Commission.
3 Q. What is the subject of your testimony?
4 A. I am presenting testimony on property taxes and income taxes.
5 Exhibit ___ (JAR-1), Schedules 1 through 3 are related to property
6 tax and Exhibit ___ (JAR-2), Schedules 1 through 4 and Exhibit ___
7 (JAR-3), Schedules 1 through 3 are related to income tax.
8 Q. Please describe Schedule 1 of Exhibit ___ (JAR-1).
9 A. Schedule 1 reports the actual property taxes expensed for the
10 Historic Year as well as projected property taxes expensed for the
11 Link Period and Rate Year.
12 Q. Please describe the jurisdictions in which the Company pays
13 property taxes in New York.
14 A. There are four main types of jurisdictions that assess property
15 taxes upon Distribution's property and plant in New York. The first
16 is the Town/County tax that has a calendar tax year. The next is
17 the School tax that has a tax year which ends each June. The third
18 is the Village tax which has a May ending tax year. The last is the
19 City taxes, which have varying tax years. The City of Buffalo is the
20 largest of the City taxes and has a June ending tax year.

DIRECT TESTIMONY OF JAMES A. RIZZO

1 Q. Please describe the methodology used to project property taxes.
2 A. Actual property taxes paid for the historic year were adjusted by the
3 Company's inflation calculation (shown in Exhibit ___(JAR-1),
4 Schedule 2, Page 1 of 1) plus a change in the overall assessments
5 for the twelve months ending March 2017 and 2018. These
6 projections were allocated into monthly expense amounts based on
7 the particular tax year. The projected expenses for the Rate Year
8 Ending March 2018 are on Exhibit ___(JAR-1), Schedule 1, Page 4
9 of 4.
10 Q. Why is it reasonable to use a rate of inflation to forecast property
11 taxes in the rate year?
12 A. It is reasonable because it reflects the current New York State
13 property tax cap policy. I will discuss the details of such property
14 tax cap policy later in my testimony.
15 Q. Would it be appropriate to apply a historical average of increase to
16 a current value of tax in order to project the future taxes to be paid?
17 A. No. For example, as a result of a favorable court case decision
18 challenging assessments, property taxes might decrease in a given
19 year. The use of an average would be totally inappropriate in that
20 event, because, once the property taxes are re-set, the rate of

1 increase will continue, albeit from a lower level. Use of an average
2 would not capture the increase. It must be remembered that the
3 factors influencing tax expenses vary from year to year and among
4 tax jurisdictions, often complicated by political considerations.
5 Q. Does New York State have a Property Tax cap?
6 A. Yes, ostensibly it does. Chapter 97 of the Laws of 2011
7 established a tax levy limit (generally referred to as the tax cap) that
8 affects all local governments (including counties, cities, towns,
9 villages, school districts and special districts). Under this law, the
10 property taxes levied by affected local governments and school
11 districts generally cannot increase by more than 2 percent, or the
12 rate of inflation, whichever is lower. Nevertheless the so-called
13 "cap" is not inviolate, as the law does allow governments and
14 school districts to levy an additional amount for certain excludable
15 expenditures. An override of the levy limit is also permitted.
16 Key provisions in the law include:
17 • Commencing with the fiscal years that begin in 2013, the law
18 gives taxing jurisdictions the ability to carryover "unused" levy
19 limits amounts from one year into the next. If a local
20 government or school district levies less than the levy limit in the

1 prior fiscal year or school year, the unused portion of the prior
2 years' tax levy limit, up to 1.5 percent can be carried over into
3 the next fiscal year.
4 • An adjustment for certain tax base growth, such as new
5 construction (i.e. "tax base growth factor"). This is driven by a
6 "quantity change factor" which is calculated by the Department
7 of Taxation and Finance and is used in determining that tax
8 base growth factor, if any, for each local government and school
9 district.
10 • Exclusions from the levy limit for which a local government or
11 school district may levy an additional amount. These include:
12 - A tax levy necessary for expenditures for a coming fiscal
13 year for employer contributions to local government and school
14 districts for the New York State and Local Employees'
15 Retirement System and the New York State and Local Police
16 and Fire Retirement System caused by growth in the "system
17 average actuarial contribution rate" in excess of 2 percentage
18 points.

1 - A tax levy necessary for expenditures resulting from court
2 orders or judgments arising out of tort actions for any amount
3 that exceeds 5 percent of the prior year tax levy.
4 - For school districts, the tax levy necessary to support the
5 local portion of capital expenditures.
6 - Adjustments for cost and savings, as determined by the
7 State Comptroller, due to the transfer of functions from one local
8 government to another.
9 The law also gives local government and school districts the option
10 to override the tax cap for the coming fiscal or school year. The
11 process by which this can happen will differ depending on whether
12 the entity is a local government or school district. In order to
13 override, the governing board of a county, city, town or village must
14 first enact a local law. The law must be approved by 60 percent of
15 the total voting power of the governing board.
16 School districts may override the tax levy limit by presenting to the
17 voters a budget that requires a tax levy that exceeds the statutory
18 limit. However, the budget must be approved by 60 percent of the
19 votes cast. If that budget does not pass, the school board may
20 adopt a final budget with no growth in the tax levy from the prior

1 year or resubmit the original or revised budget. If the resubmitted
2 budget is defeated, the district must adopt a final budget with a tax
3 levy that is no greater than the levy of the prior year. Districts may
4 also pass separate referenda on individual programs which, if they
5 cause the levy to go over the cap, would each need a 60 percent
6 vote to pass. Each district's cap is different because of a
7 complicated formula and can be higher or lower than 2 percent.
8 Further, the district can override the tax cap.
9 Q. Please describe the historical assessment of the property taxes.
10 A. Complex utility plant is centrally valued annually by the New York
11 State Office of Real Property Tax Services ("ORPTS"). ORPTS
12 provides full value assessments to the taxing jurisdictions for all
13 utility plant in the public or highway right of way ("Special
14 Franchise") and when requested, plant in the private right of way for
15 jurisdictions with an equalization rate of 100%. Consequently,
16 property tax assessed values are determined at the state (ORPTS)
17 level, as explained in detail below.
18 The Company provides detailed plant data to ORPTS on an annual
19 basis. In addition, the Company must file "Significant Change"

1 reports, on or before August 15 for incremental plant activity
2 between January 1 and June 30 of filing year.
3 After ORPTS collects this information from the Company in Original
4 Cost ("OC") format, they perform a series of calculations to arrive at
5 an assessed value. For Special Franchise property, OC data is
6 converted to Reproduction Cost New ("RCN") utilizing the
7 appropriate Handy Whitman index for plant type, material and
8 vintage. The value of any functional or economic obsolescence
9 award (discussed later in this testimony) will then be deducted from
10 the RCN, and then depreciated based on plant type, material and
11 vintage to arrive at Reproduction Cost New Less Depreciation
12 ("RCNLD"). RCNLD is further modified by the "Intangible
13 Adjustment", a minimum of five percent, to ultimately arrive at the
14 Tentative Assessed Value. The same process is performed for
15 property in the private right of way with the exception of the
16 intangible adjustment.
17 ORPTS provides Special Franchise assessed values at full value to
18 all jurisdictions. They also provide assessed values at full value for
19 property in the private right of way, to jurisdictions at full value, with
20 an equalization rate of 100%, in the form of Advisory Appraisals.

1 In addition to providing the initial data that is used by ORPTS to
2 determine assessed values, the Company also has the opportunity
3 to seek a reduction in assessed values through claims of
4 obsolescence.
5 Q. What types of obsolescence awards are available to utility
6 property?
7 A. There are two types of obsolescence available to utility property.
8 Economic Obsolescence is the loss of value of property caused by
9 an impairment in desirability or useful life resulting from factors
10 external to the property. In the case of the Company, economic
11 obsolescence factors include the economic climate of Western New
12 York (i.e., population losses, plant cutbacks/closings, relatively poor
13 income performance, shrinking natural gas consumption data, etc.).
14 Functional Obsolescence is the impairment of operating capacity or
15 efficiency resulting in the loss of value brought about by the failure
16 of the tangible property (i.e., pipeline network) to meet present or
17 projected needs, or where the capacity of the tangible property
18 exceeds reasonable and anticipated demands.
19 The Company has transitioned from an economic obsolescence
20 only environment to a blend of both economic and functional

1 obsolescence to its current functional obsolescence only position,
2 as shown on Exhibit ___(JAR-1), Schedule 3, Page 1 of 2.
3 Q. Please describe the Company's functional obsolescence initiatives.
4 A. The Company has functional obsolescence in certain of its gas
5 mains as a result of operating capacity that was sized to meet
6 industrial load of heavy manufacturing, such as steel, that have
7 long since departed the Company's service territory. Much of the
8 system was also sized to an earlier time where, due to lack of
9 insulation, weatherization and efficient natural gas appliances, the
10 average residential customer used significantly more gas than is
11 used today.
12 Q. How often are functional obsolescence applications filed?
13 A. Functional obsolescence requests are filed annually. An updated
14 system-wide study, however, is only required every five years due
15 to the complexity of the study. The Company has filed two system-
16 wide studies for functional obsolescence consideration. The initial
17 study consisted of only the medium pressure system and had a
18 five-year duration with awards ranging from 16 percent to 24
19 percent. The most recent system-wide study added the low

1 pressure system. It is in its third year of usage and has had awards
2 of 26 percent.
3 Q. What is the current state of obsolescence awards?
4 A. As can be seen in Exhibit ___(JAR-1), Schedule 3, Page 1 of 2,
5 over time, awarded functional obsolescence values have levelized
6 at a 26% value.
7 Q. Which gas main accounts are impacted by the current functional
8 obsolescence awards?
9 A. Exhibit ___ (JAR-1), Schedule 3, Page 2 of 2 identifies the gas
10 main accounts impacted by the current functional obsolescence
11 award.
12 Q. In addition to pursuing obsolescence claims, what actions has the
13 Company taken to manage the property tax burden?
14 A. The Company has developed an internal program that replicates
15 the calculation performed by ORPTS. The Company also reviews
16 all Notice of Change of Assessments received from the taxing
17 jurisdictions to assure that the assessed values agree with the
18 already reconciled ORPTS values and that the proper equalization
19 rates are applied.

1 In addition to the Company's central valuation due diligence
2 at the ORPTS level, the Company continually reviews assessments
3 that are outside of ORPTS purview such as non-utility plant
4 structures (Company service centers, commercial offices, office
5 buildings), special districts, proper equalization treatment and utility
6 plant in the private right of way for jurisdictions that have not
7 received advisory appraisals for many years.
8 The local assessor is tasked with the valuation of non-utility plant
9 structures. The Company periodically reviews these assessments
10 and takes action when appropriate. These actions include
11 engaging valuation experts to perform appraisals, which are used
12 as evidence to justify reductions in assessed values.
13 Q. What other actions does the Company take to manage its property
14 tax burden?
15 A. When the Company identifies a discrepancy between a taxing
16 jurisdiction's property tax assessment and the Company calculated
17 value (using the ORPTS valuation techniques), the appropriate
18 documentation is provided to the assessor which usually results in
19 the assessor correcting the tax roll. When these discussions prove
20 unsuccessful, the Company will file a complaint before the local

1 Board of Assessment review ("BAR"). If either the taxpayer or the
2 taxing authority are not satisfied with the BAR ruling, then litigation
3 is the only remaining alternative. For example, when discussion
4 proved unfruitful, the Company was forced to file a Petition under
5 Article 7 of the Real Property Tax Law to review the real property
6 assessments against the Town of Arkwright. That case was
7 successfully concluded with a Stipulation and Consent Order for
8 Settlement in July 2014.
9 In addition, the Company is vigilant concerning taxes levied
10 by so-called "Special Districts" which are items outside the general
11 town tax for services such as water, sewer, lighting and
12 garbage/refuse. Special districts taxes are levied by the individual
13 taxing jurisdictions and vary greatly. For example, the Company
14 was able to secure the removal of the garbage/refuse district tax
15 that had been levied by the Town of Tonawanda. The Company
16 also successfully challenged the Town of Cheektowaga's
17 garbage/refuse tax through an Article 78 Petition.
18 Q. Please refer to Schedule 1 of Exhibit ___ (JAR-2), and give a
19 general description of this schedule.
20 A. Schedule 1 of Exhibit ___ (JAR-2) consists of a detailed

1 computation of the current and deferred federal income tax
2 provision per books for the twelve months ended December 31,
3 2015, and the rate year for the twelve months ending March 31,
4 2018. The starting point to compute federal income tax is operating
5 income before income taxes. Certain additions and deductions are
6 made to arrive at taxable income, to which the statutory rate of 35-
7 percent is then applied. This schedule also reflects the
8 computation of the New York State current and deferred income tax
9 at the statutory rate of 7.1 percent for the historic year and 6.5
10 percent for the Rate Year as a result of a change in tax law enacted
11 by New York State. Per this legislation, the flat 6.5 percent rate
12 applies to tax years beginning on or after January 1, 2016. This
13 lower rate is effective for the Company in fiscal year 2017
14 beginning October 1, 2016.
15 Q. Please describe the methodology used in computing Income Tax
16 Depreciation for the Rate Year ending March 31, 2018.
17 A. Income Tax Depreciation is computed under the methods and
18 procedures permitted by the Internal Revenue Service and adopted
19 by the Company. It includes bonus depreciation where applicable.
20 New York State does not allow first year bonus depreciation for

1 property placed in service on or after June 1, 2003.

2 Q. Does the Company have any open or unresolved issues related to

3 IRS audits?

4 A. Yes. The only unresolved tax issue relates to the tentative

5 settlement of the IRS proposed disallowance of the Company's

6 change in accounting method for determining whether expenditures

7 relating to utility network property are capital or deductible as a

8 repair for tax purposes.

9 In 2009, the Company filed an application with the IRS National

10 Office to change its tax accounting method for utility network

11 property. The proposed method sought to treat certain

12 expenditures, which were capitalized for book purposes, as

13 deductible repairs for tax purposes. By doing so, the additional

14 repair deductions (for tax purposes only) would reduce the income

15 tax liability of the company. It is to be noted that the change in

16 accounting method related solely to the Company's tax filings, and

17 has no effect on the capitalization policies followed for book

18 purposes. The IRS National Office approved the request, subject to

19 review by local IRS examiners.

20 The federal tax return filed for Fiscal 2009 included an additional

1 tax deduction for the Company of $16,322,672 relating to the
2 change in method for fiscal 2009, and a $115,342,953 "catch-up"
3 amount relating to prior years. The local IRS examiners, citing a
4 lack of guidance from their technical advisors and other factors,
5 disallowed most of the claimed deduction. The Company filed a
6 formal protest and requested a conference with the IRS Appeals
7 division. A conference was held on July 14, 2011, but the Appeals
8 officer chose not to make a decision until the release of guidance
9 from the National Office, which is discussed below. The local IRS
10 examiners also disallowed deductions under the new accounting
11 method claimed in fiscal 2010 and fiscal 2011.
12 Because a number of gas utility companies were experiencing
13 difficulties with the IRS over this issue, the industry sought to have
14 the property capitalization issue accepted into the IRS "industry
15 issue resolution" ("IIR") program. Under this program, IRS
16 technical advisors and industry personnel attempt to reach a
17 mutually acceptable resolution of a contentious tax issue which
18 affects an entire industry. The capitalization issue was accepted by
19 the IRS into the IIR program, and Distribution was one of the
20 industry representatives chosen to participate. The IRS/Industry

1 group held a number of meetings and conference calls beginning in
2 May 2011, and ending its work in March 2012, having developed a
3 draft revenue procedure that was acceptable to both the IRS team
4 and the gas industry representatives. A revised revenue procedure
5 was presented by the IRS team to the gas industry representatives
6 on July 22, 2014, at which time the industry representatives
7 expressed their agreement. The draft revenue procedure is
8 presently being reviewed by officials in the IRS and Treasury Dept.
9 A specific release date has not been announced.
10 In March 2013, the local IRS examiners withdrew their proposed
11 disallowance. The IRS indicated in their Notice of Proposed
12 Adjustment that "until...guidance is issued, Exam will not audit this
13 issue and is not expressing an opinion regarding this issue at this
14 time. The IRS neither accepts nor rejects the position taken in the
15 tax return(s) related to the proper method of accounting for
16 expenditure related to natural gas transmission and distribution
17 property. This issue may be examined further at another time."
18 This "stand down" policy applies to fiscal years 2009 through 2015.
19 Since a "fully normalized" approach is used in New York for
20 ratemaking purposes, the additional tax deduction relating to the

1 change in method resulted in additional deferred income taxes,
2 similar to the treatment of accelerated tax depreciation.
3 Q. Please refer to Schedule 2 of Exhibit ___ (JAR-2) and give a
4 general description of this schedule.
5 A. This schedule shows the accumulated deferred income tax balance
6 related to accelerated tax depreciation per books for the twelve
7 months ended December 31, 2015 and the projected balance for
8 the twelve months ending March 31, 2018.
9 Q. Please refer to Schedule 3 of Exhibit ___ (JAR-2). What does this
10 schedule show?
11 A. This schedule shows the accumulated deferred investment tax
12 credit balance per the books as of December 31, 2015 and the
13 projected balance for the twelve months ending March 31, 2018.
14 Q. Please explain the adjustment to operating income for Medicare
15 subsidies received that is presented on Schedule 1, Page 1 of
16 Exhibit ___(JAR-2).
17 A. The Medicare Act of 2003 established a tax-free subsidy for a
18 portion of an employer's annual prescription drug costs. In
19 November 2006, the Commission issued an order in Case 04-M-
20 1693 adopting accounting for 2003 Medicare Act effects. In 2010,

Q. Please state your name and business address.

A. My name is James A. Rizzo. My business address is 6363 Main Street, Williamsville, New York 14221-5887.

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

A. I am employed by National Fuel Gas Distribution Corporation ("Distribution" or the "Company") as Assistant Vice President in the Tax Department.

Q. Have you previously provided testimony in this case?

A. Yes. I provided Direct Testimony, Exhibits and workpapers regarding the Company's Property Taxes and Income Taxes.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of the testimony is to respond to the testimony of Staff witness Richard Davi concerning Property Taxes and Income Taxes and discuss discrepancies noted in the Staff Accounting Panel's calculation of Income Taxes in Staff Exhibit_(SAP-1), Schedule 3 of 10.

PROPERTY TAXES

Q. Do you agree with witness Davi's testimony regarding the use of a zero percent growth rate for projecting property taxes in the rate

year?

A. No. I do not agree with this arbitrary approach, which was based upon an analysis of the three-year average changes in property taxes.

Q. Why is using an approach that is based on a three-year average inappropriate?

A. The use of the three-year average is inappropriate because it is not a valid proxy for real property tax expense going forward. Witness Davi's testimony indicates that the three-year average produces a negative growth rate of 0.29 percent, an amount which he recognizes is unsustainable. However, witness Davi then decides to arbitrarily propose a growth rate of zero percent. I agree that the negative growth rate experienced in the three-year period is not a proper yardstick for measuring future property tax expense in this rate case, but neither is a zero percent growth factor sustainable, or appropriate.

Q. Please explain.

A. In recent years, the Company has received increasing functional obsolescence awards which led to lower assessed values and property taxes. However, the amount of the awards has levelled off

over the past few years and is expected to decline in the future as a result of the Company's Leak Prone Pipe Program (discussed later), and other pipeline projects. As the functional obsolescence awards decline, additional capital expenditures will lead to increased property tax expense given that the property tax increase associated with the Company's plant additions will no longer be offset by increasing functional obsolescence awards.

Q. Why is it inappropriate to apply a zero percent growth rate to project the future property taxes to be paid?

A. As explained in my Direct Testimony, actual property taxes paid in the historic test year were adjusted by the Company's inflation factor plus an estimated change in the overall assessments. The use of inflation for forecasting property tax expense provides a reasonable, sustainable estimate for the rate year therefore, as provided in my Direct Testimony, I propose that an inflation factor be applied to property taxes due to an inevitable increase in tax expense.

Q. In addition to an inflation factor, are there other adjustments that should be made to property taxes in the Rate Year?

A. Yes. In addition to tax rates, changes in assessments affect property

taxes. The Company has reflected an estimate of change in overall assessment value in its projection.

Q. Please explain.

A. As part of the Company's overall capital expenditures program, the Company has implemented programs that will directly result in an increase in property taxes in the future.

Q. What Company programs would increase property taxes in the future?

A. The Company's Leak Prone Pipe (LPP) Replacement Program (as noted in the Direct Testimony of Kevin D. House) would have an obvious impact on future property tax expenses. As older gas pipelines are replaced with newer and more appropriately-sized pipe, the Company's functional obsolescence award will necessarily decrease. This will result in increased assessed values and increased property taxes. Also, the replacement pipelines will have a higher assessed value (and higher property taxes) as a result of having less accumulated depreciation than the older pipelines.

The Gas Network Enhancement Pilot Program (as noted in the Direct Testimony of the Energy Services Panel) will also lead to

increased property taxes as new pipelines are added to the Company's gas network.

ACCUMULATED DEFERRED INCOME TAXES

Q. What is the "proration" methodology as it relates to the calculation of accumulated deferred income taxes (ADIT) in this rate filing?

A. The proration methodology is a specific method promulgated by the IRS for calculating ADIT for any rate filing that includes a future test period. For purposes of proration, a future test period is any period after the date on which new rates are scheduled to go into effect. In the current rate filing, the future test year (or future "rate year") is the 12-months ending March 2018, with new rates scheduled to go into effect on or about April 1, 2017.

Q. Where is the proration methodology described by the IRS?

A. It is explained in Reg. 1.167(l)-1(h)(6)(ii). It is also discussed in recent IRS private letter rulings (PLRs), including PLR 201541010 and PLR 201531010.

Q. Why is use of the proration methodology important?

A. The Company must use the proration methodology in order to comply with the normalization requirements of the Internal Revenue

Code. Compliance with the normalization rules is necessary in order for a company to claim accelerated depreciation for tax filing purposes. Accelerated tax depreciation, versus straight-line depreciation, provides a cash-flow benefit for a company. Ratepayers benefit from this via a rate base reduction for the ADIT.

Q. Please explain the mechanics of the proration methodology.

A. The methodology is designed to account for the period of time the Company has received the ADIT, and provide the appropriate limit on the amount of ADIT that can be excluded from rate base as determined by the IRS. Under the proration methodology the pro-rata amount of any increase in ADIT during the future rate year is determined by multiplying the increase by a fraction, the numerator being the number of days remaining in the future period at the time of the increase (in our case, increases are projected on a monthly basis), and the denominator being the total number of days in the future period (in our case, 365). Using the required proration methodology, the Company calculated the final ADIT balance in its current rate filing as follows: The starting point is the projected ADIT balance at April 1, 2017, the beginning of the future rate year.

Next, the deferred tax increase projected for April 2017 is multiplied by 335/365 and added to the previous balance; then the deferred tax increase projected for May 2017 is multiplied by 304/365 and added to the balance; and so forth through March 2018, the end of the future rate year. Finally, consistent with the determination of rate base for the future rate year, the beginning and ending balances of ADIT for the future rate year are averaged to arrive at the final ADIT balance. Please refer to Exhibit ___ (JAR-3) Schedule 1, Page 2 of 2 for the calculation.

Q. Why must the proration methodology be used in this rate filing?

A. The use of the proration methodology is REQUIRED in a rate filing such as this one, which includes a future test period, to enable the Company to comply with the normalization requirements and claim accelerated depreciation for tax filing purposes. As noted earlier in this testimony, the Company receives a cash-flow benefit from accelerated tax depreciation (via a reduction in current income taxes payable) and ratepayers receive a benefit as a result of the reduction in rate base related to the ADIT. Although witness Davi's testimony indicates that he believes his methodology approximates

the results of using proration, his method is, in fact, not consistent with the proration methodology. In verifying witness Davi's calculation, using Staff's proposed adjustments for capital expenditures and uncollectible expense, the ADIT balance using the proration methodology is calculated to be $247,738 as opposed to $250,021 calculated using witness Davi's approach. See Exhibit_(JAR-3) Schedule 2, Page 1 of 1. The use of witness Davi's estimation would result in a violation of the normalization requirements noted above and would prohibit the Company from claiming accelerated depreciation (including bonus depreciation), which would have adverse consequences for ratepayers. Therefore, it is essential that the proration methodology be followed properly in this case. The Company will update the ADIT calculation under the proration methodology through the Brief on Exceptions phase of this proceeding.

NYS Tax Rate Change

Q. Do you agree with Staff's proposal to pass back excess ADSIT to ratepayers over a three-year period?

A. Yes, provided that the Company would receive consistent deferral treatment if tax rates were to increase. As previously mentioned in DPS-39, the Company estimated the excess ADSIT amount for purposes of this rate case. The amount should be finalized after the year end closing of the accounting records. The Company is requesting deferral treatment for any difference between the estimated amount reflected in the final revenue requirement and the actual amount. Any under/over recovery would be recovered from or returned to ratepayers as appropriate in a future rate case. In addition, any future state tax rate increases would be deferred and recovered from ratepayers in a future rate case.

Q. Please explain any discrepancies in Staff Exhibit_(SAP-1), Schedule 3 of 10.

A. Staff Accounting Panel's proposed adjustments were not properly reflected in the current and deferred tax calculation included in Staff Exhibit_(SAP-1), Schedule 3 of 10. Specifically, Staff's proposed adjustments for depreciation expense and uncollectibles expense should be included in this calculation as these changes impact the calculation of federal and state taxable income.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, at this time.

1 the Patient Protection and Affordable Care Act ("PPACA") amended
2 the law and made all subsidies received after October 1, 2013
3 taxable to the Company. The Company began amortization of this
4 benefit in January 2008 at a rate of $36,974 per month (as provided
5 for in Case 07-G-041) and the balance will be fully amortized in
6 January 2017.
7 Q. Are you familiar with the Affiliate Rules adopted in Case 04-G-
8 1047?
9 A. Yes I am familiar with the Affiliate Rules.
10 Q. Are you in compliance with these rules insofar as they govern Tax
11 Department functions (where applicable)?
12 A. Yes.
13 Q. Does this conclude your direct testimony?
14 A. Yes, at this time.

A.L.J. LECAKES: Were there exhibits attached to either of Mr. Rizzo's testimony?

MR. NICKSON: Yes, Your Honor. There are two exhibits attached to his direct testimony identified as JA -- AR1 and JAR2 and one exhibit attached to his rebuttal testimony identified as JAR3 and I ask that each of those documents be marked for identification.

A.L.J. LECAKES: So 68 for JAR1, 69 for JAR2, and then 70 for JAR3. The next witness?

MR. NICKSON: The next witness is Jodi J. Smith. Ms. Smith prepared the testimony entitled Direct Testimony of Jodi J. Smith which consists of 11 pages of questions and answers. I ask that the Direct Testimony of Jodi J. Smith be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted and that would be Smith Direct Testimony in the company Direct Testimony folder. The affidavit will be marked as Exhibit 71.

DIRECT TESTIMONY OF JODI J. SMITH

1 Q. Please state your name and business address.

2 A. My name is Jodi J. Smith, and my business address is 6363 Main
3 Street, Williamsville New York, 14221.

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

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

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

8 A. I graduated from the State University of New York at Buffalo in
9 1998 with a Bachelor of Science degree in Accounting. Shortly
10 after graduation, I began my employment in public accounting with
11 Lumsden & McCormick, LLC. In 2001, I joined Distribution as a
12 General Accountant. My current position is Senior Financial
13 Analyst, working in the Finance Department.

14 Q. Are you familiar with the Affiliate Rules adopted in Case 04-G-
15 1047?

16 A. Yes I am familiar with the Affiliate Rules.

17 Q. Is your department compliant with these rules insofar as they
18 govern Distribution employees providing services to affiliated
19 entities?

20 A. Yes

DIRECT TESTIMONY OF JODI J. SMITH

1 Q. What is the purpose of your testimony?

2 A. My testimony reviews the actual and projected capitalization ratios
3 and the sources and uses of funds for National Fuel Gas Company
4 ("NFGC"), the parent of Distribution. I am also responsible for the
5 debt cost ratios presented in this case.

6 FINANCIAL INFORMATION / DEBT COST RATES

7 Q. Please refer to Exhibits___(JS-1) through Exhibit__(JS-3) and
8 describe them.

9 A. These Exhibits show actual and projected financial data for NFGC
10 and subsidiaries for the twelve month period ending December 31,
11 2015, and projected financial data for NFGC for various periods
12 through September 30, 2020. Specifically,

13 • Exhibit___(JS-1) Sheet 1 sets forth investor provided
14 capitalization and capital structure ratios (actual) at
15 December 31, 2015 and projected at September 30, 2018,
16 2019, and 2020. Projected data for periods subsequent to
17 September 30, 2017 are only available on a fiscal year
18 ended September 30 basis. Thus, fiscal year ended
19 September 30, 2018 data is provided as a proxy for the rate
20 year ("Rate Year") and September 30, 2019 and 2020 for the

1 two years following the Rate Year. The common equity
2 amounts presented for all periods exclude accumulated
3 other comprehensive income. Sheets 2 and 3 demonstrate
4 and describe information employed to project the
5 capitalization of NFGC.
6 • Exhibit___(JS-2) presents NFGC's (parent) composite
7 interest rate of debt both at December 31, 2015 and
8 projected at September 30, 2018, 2019 and 2020.
9 • Exhibit___(JS-3), Sheets 1 through 3, shows projected
10 sources and uses of funds for Distribution and NFGC for the
11 twelve months ending September 30, 2018, 2019 and 2020.
12 Q. What cost rates have you assigned to the debt portion of the capital
13 structure for the years ending September 30, 2018, 2019 and
14 2020?
15 A. The embedded cost of debt, which reflects both long-term and
16 short-term borrowings, is 5.21%, 5.12% and 5.08% for the years
17 ended September 30, 2018, 2019 and 2020, respectively, as
18 developed on Exhibit___(JS-2), Sheets 2-4. This exhibit shows the
19 computation of the estimated cost rates of debt based upon the
20 average balances for each series of long-term notes for the

1 thirteen-month periods ending September 30, 2018, 2019 and
2 2020. Short-term debt is presented on an average balance for the
3 periods ended September 30, 2018, 2019 and 2020. Sheet 1
4 details the computation of the cost rate of debt at December 31,
5 2015. Sheet 5 describes information relevant to the calculations
6 contained on Sheets 1 through 4. The calculation of the effective
7 interest rate by long-term debt instruments is provided on
8 Exhibit___(JS-2), Sheets 6 through 8. The composite interest rate
9 at December 31, 2015 and estimated for the Rate Year and
10 following two years reflects the refinancing adjustments to both the
11 balance of long-term debt and the annualized cost. Details of the
12 base year refinancing adjustments can be found on Sheet 10 of
13 Exhibit___(JS-2). The base year refinancing adjustments, which
14 affect the computation of the composite interest rate of debt and
15 level of debt capital to be used in this proceeding, have been
16 updated to reflect recovery of the after tax premium amortization
17 through September 30, 2020. The summary of these updates can
18 be found on Exhibit___(JS-2), Sheet 9. The rationale for these
19 refinancing adjustments is consistent with testimony sponsored by
20 Distribution witnesses in Cases 29679, 88-G-180, 89-G-179, 90-G-

1 0734, 91-G-0846, 93-G-0756, 94-G-0885, 95-G-1009, 04-G-1047
2 and 07-G-0141 before the New York State Public Service
3 Commission ("Commission") and continues to have merit. The
4 computation of the individual effective cost rate for each series of
5 debentures reflected on Sheets 6 through 8 uses the "Coupon
6 Interest Rate" technique adopted by the Commission in Case
7 28447.
8 Q. Does the embedded cost of debt for the periods ended September
9 30, 2018, 2019 and 2020 assume any new long-term debt
10 issuances?
11 A. Yes, it assumes that on April 1, 2018 NFGC will issue $300 million
12 of medium term notes that carry a coupon interest rate of 6.755%
13 and mature in 2028. After considering an assumed $771,000 of
14 issuance costs, the effective interest rate of the issuance is
15 assumed to be 6.88%. The proceeds from the note issuance are
16 assumed to be used to re-finance $300 million of 6.5% medium-
17 term notes that mature that same month. It also assumes that on
18 April 1, 2019 NFGC will issue $250 million of medium term notes
19 that carry a coupon interest rate of 6.755% and mature in 2029.
20 After considering an assumed $642,000 of issuance costs, the

1 effective interest rate of the issuance is assumed to be 6.88%. The
2 proceeds from the note issuance are assumed to be used to re-
3 finance the $250 million of 8.75% medium-term notes that mature
4 in May 2019. The April 1, 2018 and 2019 issues are outside the
5 forecasted Rate Year and are only provided for presentation
6 consistency.
7 Q. Please describe how you calculated the assumed coupon interest
8 rate and issuance costs.
9 A. The 6.755% coupon was calculated by adding a 500 basis point
10 NFGC credit spread to a February 2016 actual 10-year benchmark
11 U.S. Treasury note yield of 1.755%. The NFGC credit spread was
12 obtained from indicative new issuance estimates provided by
13 NFGC's investment banks. The $771,000 and $642,000 of
14 estimated issuance costs were based on the issuance costs of
15 NFGC's most recent debt issue in June 2015 as a percent of the
16 total principal amount of debt issued. This percent was then
17 applied to the principal amount of the projected new debt issue.
18 Q. Please describe NFGC's available sources of short-term
19 borrowings.
20 A. NFGC has established both uncommitted and committed lines of

1 short-term credit and a commercial paper program. These facilities
2 have been established for general corporate purposes and are
3 used to finance the system's working capital needs. NFGC
4 currently has arrangements to borrow up to $85 million under
5 various bilateral uncommitted lines of credit, and also maintains
6 other discretionary lines, with no set dollar limit, from which it can
7 borrow. Uncommitted credit lines are generally callable at the
8 option of the financial institution. NFGC may also issue up to $500
9 million under its commercial paper program. The commercial paper
10 program is backed by a syndicated committed credit agreement.
11 This credit agreement provides a $750 million multi-year unsecured
12 committed revolving credit facility through December 5, 2019, plus
13 a $500 million 364-day unsecured committed revolving credit facility
14 through September 29, 2016. At this time, the Company
15 anticipates the 364-day credit facility will be extended until
16 September 2017. Because it restricts the ability of an institution to
17 call the line due to events not specific to the borrower, a committed
18 line of credit provides assurance that credit will be made available
19 even when credit may be limited due to disruptions in the credit
20 markets. Because of this assurance of availability, financial

1 institutions charge a fee for providing a committed line. NFGC's
2 establishment of a committed line of credit is consistent with the
3 requirements contained in Standard and Poor's Credit Policy
4 Statement on commercial paper backup.
5 Q. How were the short-term interest rates provided in Exhibit___(JS-2)
6 Sheets 2 through 4, developed?
7 A. The short term interest rate projected in Exhibit___(JS-2) Sheets 2
8 through 4 consists of two parts: 1) the short term borrowing rate
9 charged by NFGC's lenders and 2) fees associated with NFGC's
10 credit facilities, including rating agency fees and committed line of
11 credit fees. The average short term borrowing rate was forecast to
12 be 2.25%, 2.50% and 2.50% for the twelve months ended
13 September 30, 2018, 2019 and 2020, respectively. Credit facility
14 fees are projected to be $1,805,832, $1,813,537 and $1,831,089
15 for the periods ended September 30, 2018, 2019 and 2020,
16 respectively. When the committed line of credit fees are added to
17 short term interest expense, the short term borrowing rate
18 increases to 2.76%, 2.92% and 3.06% for those same periods,
19 respectively.
20 Q. Is the estimated short term borrowing rate reasonable?

1 A. Yes. The estimated short term borrowing rate is reasonable based
2 on credit terms generally available to other borrowers with similar
3 credit profiles.
4 Q. How have you evaluated the reasonableness of the estimated short
5 term borrowing rate?
6 A. For the twelve month periods ended September 30, 2018, 2019
7 and 2020, the 1-month LIBOR forward curve averages
8 approximately 1.25%, 1.50% and 1.75%, respectively. If NFGC
9 were to utilize its committed credit facility referred to above, the
10 spread that would be added to the LIBOR rate would be 1.10%.
11 Applying an average of these two spreads to the projected 1-month
12 LIBOR rates previously mentioned leads to an approximation of the
13 projected short-term interest rates utilized in our forecast.
14 Q. Please describe in general how you developed the forecast used to
15 project the sources and uses of funds information contained in
16 Exhibit___(JS-3).
17 A. The forecasts of net income and common dividend payments on a
18 subsidiary-by-subsidiary basis for the periods ending September
19 30, 2018, 2019 and 2020 are based upon the following information
20 and major assumptions:

- Sales revenues and purchased gas costs were computed using projected rates and gas requirements and supply studies for Distribution and for National Fuel Gas Supply Corporation. The projected rates for Distribution are projected on the basis of rates of return allowed in previous cases, rather than the rate of return requested by Distribution.
- Seneca Resources revenues were estimated based on anticipated sales prices for forecasted gas and oil volumes.
- Operating and maintenance expenses were based upon budget amounts.
- Forecasts of other taxes such as payroll, property and revenue taxes were based upon estimated rates and taxable bases.
- Depreciation accruals were developed by applying current depreciation rates on existing plant and estimated additions based on amounts per construction budgets. Depletion of oil and gas revenues is computed on the unit of production method.
- State and federal income taxes were computed at statutory

1 rates using estimates of Schedule M additions and
2 deductions and investment tax credits.
3 • Interest charges were developed based upon estimated
4 short-term bank borrowings and outstanding long-term debt.
5 • Forecast information for NFGC's other non-regulated
6 subsidiaries was developed by management responsible for
7 those subsidiaries using sales, pricing and operating
8 expense forecasts that are based on their knowledge of their
9 respective subsidiaries' industry.
10 Q. Does this conclude your direct testimony?
11 A. Yes, at this time.

A.L.J. LECAKES: And were there exhibits attached to --?

MR. NICKSON: Yes, Your Honor. There were three exhibits attached to Ms. Smith's direct testimony identified as J -- JS1 through JS3 and I ask that they be marked for identification.

A.L.J. LECAKES: Marked as 72 for JS-1, 73 for JS-2, and 74 for JS-3. Next witness?

MR. NICKSON: The next witness is John J. Spanos. Mr. Spanos prepared testimony entitled The Direct Testimony of John J. Spanos which consists of a cover page, a table of contents, and 29 pages of questions and answers. Mr. Spanos also prepared testimony entitled The Rebuttal Testimony of John J. Spanos which consists of a cover page and 21 pages of questions and answers. I ask that Mr. Spanos's direct and rebuttal testimony be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. Spanos Direct Testimony file in the company Direct Testimony folder and Spanos Rebuttal Testimony in the company Rebuttal Testimony folder. The affidavit will be marked as Exhibit 75.

BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

----------x

Proceeding on Motion of the Commission as to the
Rates, Charges, Rules and Regulations of
National Fuel Gas Distribution Corporation
for Gas Service

Case 16-G-____

----------x

DIRECT TESTIMONY OF
JOHN J. SPANOS

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

April 28, 2016

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND ADDRESS.

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

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING?

A. I have been associated with the firm since college graduation in June, 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am a Senior Vice President.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of National Fuel Gas Distribution Corporation ("Distribution" or the "Company") with respect to its New York Division.

Q. PLEASE STATE YOUR QUALIFICATIONS.

A. I have 30 years of depreciation experience which includes giving expert testimony in over 200 cases before 40 regulatory commissions, including the New York Public Service Commission ("Commission" or "NYPSC"). Please refer to Appendix A for my qualifications.

Q. PLEASE SUMMARIZE THE IMPACT IN DEPRECIATION RATES BASED ON THE DEPRECIATION STUDY.

A. The table below sets forth a comparison of the current depreciation rates resultant expense to the proposed depreciation rates and expense by function as of March 31, 2018.

	Current		Proposed	
Function	**Rates**	**Proforma Expense**	**Rates**	**Expense**
Intangible	10.00	$5,879,943	9.05	$5,321,692
Production	2.98	459,123	2.62	404,200
Transmission	2.53	637,628	2.29	578,359
Distribution	2.37	31,643,649	2.53	33,792,832
General	6.02	4,645,012	8.03	6,192,203
Total		**$43,265,355**		**$46,289,286**

Q, CAN YOU EXPLAIN SOME OF THE MAJOR FACTORS THAT CAUSED THE CHANGE IN DEPRECIATION RATES?

A. Yes. The major components that caused rates to change by function are as follows:

- Intangible Plant: the decrease in expense relates to some vintages in Account 303 that are fully recovered;
- Production Plant: the longer lives for some accounts created a decrease in expense;
- Transmission Plant: the longer life in Account 367, Mains - excluding Cathodic Protection, caused the decrease in expense;
- Distribution Plant: the primary component relates to the more negative net salvage percent and shorter life for Account 376.4, Mains - Plastic;

- General Plant: the primary change relates to the shorter life for Account 392.1, Transportation Equipment Under 1 Ton; and Account 396, Power Operated Equipment.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I sponsor the depreciation studies performed for Distribution attached hereto as Exhibit __ (JJS-1) ("2015 Depreciation Study") and Exhibit __ (JJS-2) ("2018 Depreciation Study"). The Depreciation Studies set forth the calculated annual depreciation accrual rates by account as of December 31, 2015 and calculated annual depreciation accrued rates by account as of March 31, 2018. The proposed rates appropriately reflect the rates at which Distribution's assets should be depreciated over their useful lives and are based on the most commonly used methods and procedures in New York for determining depreciation rates.

Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which can be reasonably anticipated or contemplated, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence,

changes in the art, changes in demand and the requirements of public authorities.

Q. IN PREPARING THE DEPRECIATION STUDY, DID YOU FOLLOW GENERALLY ACCEPTED PRACTICES IN THE FIELD OF DEPRECIATION VALUATION?

A. Yes.

Q. ARE THE METHODS AND PROCEDURES OF THIS DEPRECIATION STUDY CONSISTENT WITH PAST PRACTICES?

A. The methods and procedures of these studies are generally the same as those utilized in the last proceeding for this company as well as others before the NYPSC. Depreciation rates are determined based on the average service life procedure and the whole life method.

III. OUTLINE OF REPORT

Q. HAVE YOU PREPARED EXHIBITS PRESENTING THE RESULTS OF YOUR STUDIES?

A. Yes. Exhibit __ (JJS-1) presents the results of the depreciation study as of December 31, 2015. Exhibit __ (JJS-2), presents the results of the depreciation study as of March 31, 2018.

Q. PLEASE DESCRIBE EXHIBIT __ (JJS-1) AND EXHIBIT __ (JJS-2).

A. Exhibit __ (JJS-1) titled "2015 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2015," includes the results of the depreciation study as related to the original cost at December 31, 2015. The report also includes the detailed depreciation

calculations. Exhibit __ (JJS-2), titled "2018 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of March 31, 2018," includes the results of the depreciation study as related to the estimated original cost at March 31, 2018. The report also includes explanatory text, statistics related to the estimation of service life, and the detailed depreciation calculations.

Q. IS THE COMPANY'S CLAIM FOR ANNUAL DEPRECIATION IN THE CURRENT PROCEEDING BASED ON THE SAME METHODS OF DEPRECIATION AS WERE USED IN ITS MOST RECENT PROCEEDING?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line whole life method of depreciation, which has been used for over twenty years. For Accounts 391.1, 391.2, 391.3, 394.1, 394.2, 394.3 and 397, the claim is based on the straight line whole life method of amortization. The accounts have a large number of units, but small asset values representing slightly more than 3 percent of the depreciable plant. The assets represent items located in office buildings, service centers, garages and warehouses. Given the difficulty in maintaining accounting records for these numerous assets and high cost for periodic inventories, retirements are recorded when a vintage is fully amortized, rather than as the units are removed from service. All units are retired when the age of the vintage reaches the amortization period. The annual amortization is based on amortization accounting which distributes

the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

Q. HAS A SERVICE LIFE STUDY OF THE COMPANY'S GAS UTILITY PROPERTY BEEN PERFORMED?

A. Yes. A service life study was performed as of December 2015. The service life study is the basis for the service lives I used to calculate annual accruals.

Q. BRIEFLY OUTLINE THE PROCEDURE USED IN PERFORMING THE SERVICE LIFE STUDY.

A. The service life study consisted of assembling and compiling historical data from the records related to the gas utility plant of the Company; statistically analyzing such data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning Company practices and plans as they relate to plant operations; and interpreting the above data to form judgments of service life characteristics.

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

Q. WHAT STATISTICAL DATA WERE EMPLOYED IN THE HISTORICAL ANALYSES PERFORMED FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. The data consisted of the entries made to record retirements and other transactions related to the gas plant during the period 1962-2015. These entries were classified by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed. Types of transactions included in the data were plant additions, retirements, transfers, and balances. In the presentation of service life statistics, only the significant exposure points that were utilized in determining survivor curves were plotted. This process is utilized to show my judgment in service life determinations.

Q. WHAT WAS THE SOURCE OF THESE DATA?

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

Q. WERE THE METHODS USED IN THE SERVICE LIFE STUDY THE SAME AS THOSE USED IN OTHER DEPRECIATION STUDIES FOR GAS UTILITY PLANT PRESENTED BEFORE THIS COMMISSION?

A. Yes. The methods are the same ones that have been presented previously for Distribution and for other gas companies before the Commission and

that have been accepted by the Commission in its past orders concerning gas utilities.

Q. WHAT APPROACH DID YOU USE TO ESTIMATE THE LIVES OF SIGNIFICANT STRUCTURES SUCH AS OFFICE BUILDINGS AND SERVICE CENTERS?

A. I used the life span technique to estimate the lives of significant structures. In this technique, the survivor characteristics of the structures are described by the use of interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the structure such as plumbing, heating, doors, windows, roofs, etc. that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the structure by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation inasmuch as concurrent retirement of all years of installation will occur when the structure is retired.

Q. HAS YOUR FIRM USED THIS APPROACH IN OTHER PROCEEDINGS BEFORE THIS COMMISSION?

A. Yes, we have used the life span technique on many occasions before the Commission.

Q. WHAT ARE THE BASES FOR THE PROBABLE RETIREMENT YEARS THAT YOU HAVE ESTIMATED FOR EACH STRUCTURE?

A. The bases for the estimates of probable retirement years are life spans for each structure that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other gas utilities for similar structures. Most of the life spans result in probable retirement dates that are many years in the future. As a result, the retirement of these structures is not yet subject to specific management plans. Such plans would be premature. At the appropriate time, studies of the economics of rehabilitation and continued use or retirement of the structure will be analyzed and the results incorporated in the estimation of the structure's life span.

Q. ARE THE FACTORS CONSIDERED IN YOUR ESTIMATES OF SERVICE LIFE PRESENTED IN EXHIBIT __ (JJS-2)?

A. Yes. A discussion of the factors considered in the estimation of service lives is presented by account on pages III-2 through III-4 of Exhibit __ (JJS-2).

Q. HOW WAS THE BOOK RESERVE AT MARCH 31, 2017, ESTIMATED?

A. The book reserve at March 31, 2017, by account, was projected by adding estimated accruals and gross salvage, and subtracting estimated retirements

and cost of removal from the book reserve at December 31, 2015. Annual accruals were estimated using the annual accruals calculated as of December 31, 2015. For most accounts, salvage and cost of removal were estimated by (1) expressing actual salvage and cost of removal as a percent of retirements by account, for the most recent five-year period, and (2) applying those percents to the projected retirements by account

Q. WAS THE BOOK RESERVE AT MARCH 31, 2018, ESTIMATED USING THE SAME METHODOLOGY?

A. Yes. The book reserve for the twelve months ended March 31, 2018 was projected using the same methodology as that which was calculated to develop the March 31, 2017 book reserve. The annual accrual rates as of December 31, 2015 were multiplied by the average plant balance of the twelve months ended March 31, 2018, and added to the March 31, 2017 book reserve. Projected retirements, gross salvage and cost of removal were also included in the development of the book reserve. Table 2B sets forth the development of the book reserve as of March 31, 2018.

Q. PLEASE OUTLINE THE CONTENTS OF EXHIBIT __ (JJS-2).

A. Exhibit __ (JJS-2) is presented in nine parts. Part I, Introduction, sets forth the scope and basis of the study. Part II, Estimation of Survivor Curves, includes a description of the Iowa Curves and the formulation of the retirement rate method. Part III, Service Life Considerations, Part IV, Net Salvage Considerations, and Part V, Calculation of Annual and Accrued

Depreciation, include a description of the judgment utilized for life parameters and the explanation of depreciation procedures.

Part VI, Results of Study, presents a description of the results and summaries of the depreciation calculations. Part VII, Service Life Statistics, presents the graphs and tables which relate to the service life study. Part VIII, Net Salvage Statistics, presents the results of the net salvage analyses. Part IX, Detailed Depreciation Calculations, sets forth the detailed depreciation calculations by account

Table 1, pages VI-5 and VI-6 presents the estimated survivor curve, the original cost at March 31, 2018, and the calculated annual and accrued depreciation for each account or subaccount of Gas Plant. Tables 2A and 2B, pages VI-7 and VI-8 presents the bringforward to March 31, 2018, of the book depreciation reserve as of December 31, 2015. Tables 3A and 3B on pages VI-9 and VI-10 sets forth the calculation of the annual accruals used in the bringforward. Table 4, page VI-11, presents the comparison of the calculated accrued depreciation to the book reserve as of March 31, 2018.

The section beginning on page VII-1 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page IX-1 presents the depreciation calculations related to original cost.

Q. PLEASE OUTLINE THE CONTENTS OF EXHIBIT __ (JJS-1).

A. Exhibit __ (JJS-1) includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of December 31, 2015. The descriptions and explanations presented in Exhibit __ (JJS-2) are also applicable to the depreciation calculations presented in Exhibit __ (JJS-1). The graphs and tables related to service life presented in Exhibit __ (JJS-2), also support the service life estimates used in Exhibit __ (JJS-1), inasmuch as the estimates are the same for both test years. The tables related to net salvage analyses presented in Exhibit __ (JJS-2) support the estimates of net salvage percentages. The summary tables and detailed depreciation calculations as of December 31, 2015, are organized and presented in the same manner as those as of March 31, 2018.

IV. METHODS AND PROCEDURES USED IN THE STUDY

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the annual depreciation accrual rates and accrued depreciation based on the service life and net salvage estimates determined in the first phase.

Q. PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage study consisted of compiling historical data from records related to Distribution's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other gas utilities to form judgments of average service life and net salvage characteristics.

Q. WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. Generally speaking, I analyzed the Company's accounting entries that record plant transactions during the period 1962 through 2015. The transactions included additions, retirements, transfers, sales and the related balances.

Q. WHAT METHOD DID YOU USE TO ANALYZE THESE SERVICE LIFE DATA?

A. I used the retirement rate method. This is the most appropriate method when retirement data covering a long period of time is available because

this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the depreciation study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE DISTRIBUTION'S SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa type survivor curves were used to perform these interpretations.

Q. WHAT IS AN "IOWA-TYPE SURVIVOR CURVE" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?

A. Iowa type curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of

observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 58-R1.5 indicates an average service life of fifty-eight years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 1.5, for the mode (possible modes for R type curves range from 1 to 5).

Q. DOES THE DEPRECIATION STUDY INCLUDE ONLY IOWA CURVE ANALYSES?

A. Yes. In other recent cases in New York, the New York State Department of Public Service Staff has been comfortable with the Iowa curves as the primary presentation of life analyses. The Iowa curves are the traditional method used by every other utility regulating agency across the United States.

Q. DID YOU PHYSICALLY OBSERVE DISTRIBUTION'S PLANT AND EQUIPMENT AS PART OF YOUR DEPRECIATION STUDY?

A. Yes. I made field reviews of Distribution's property as part of this study during March 2016 to observe representative portions of plant. Field reviews were conducted to become familiar with Company operations and to obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with management, was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. WOULD YOU EXPLAIN THE CONCEPT OF "NET SALVAGE"?

A. Net salvage is a component of the service value of capital assets that is reflected in depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage.

Inasmuch as depreciation expense is the loss in service value of an asset during a defined period, e.g. one year, it must include a ratable portion of both the original cost and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost so that customers receiving service from the asset

pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value.

For example, the full recovery of the service value of a $1,000 regulator includes not only the $1,000 of original cost, but also, on average, $200 to remove the regulator at the end of its life and $50 in salvage value. In this example, the net salvage component is negative $150 ($50 - $200), and the net salvage percent is negative 15% (($50 - $200)/$1,000).

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. I estimated the net salvage percentages by reviewing the Company's account specific historical salvage and cost of removal data for the period 1962 through 2015 as a percentage of the associated retired plant as well as considering industry experience in terms of net salvage estimates for other gas companies.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group, using the straight line whole life method, and the average service life procedure.

Q. PLEASE DESCRIBE THE STRAIGHT LINE WHOLE LIFE METHOD OF DEPRECIATION.

A. The straight line whole life method of depreciation allocates the original cost of the property, less future net salvage, in equal amounts to each year of service life.

Q. PLEASE DESCRIBE AMORTIZATION ACCOUNTING.

A. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. Amortization accounting is used for accounts with a large number of units, but small asset values. Depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirements. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period which represents an anticipated life during which the asset will render full benefit. For example, in amortization accounting, assets that have a 25-year amortization period will be fully recovered after 25 years of service and taken off the Company's books, but not necessarily removed from service. In contrast, assets that are taken out of service before 25 years remain on the books until the amortization period for that vintage has expired.

Q. FOR WHICH PLANT ACCOUNTS IS AMORTIZATION ACCOUNTING BEING UTILIZED?

A. Amortization accounting is utilized for certain General Plant or General Plant-related accounts. These accounts are Accounts 391.1, 391.2, 391.3, 394.1, 394.2, 394.3 and 397 in gas plant. These accounts represent slightly more than 3 percent of the Company's depreciable plant.

V. EXAMPLE OF PRESENTATION

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE HOW THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IS PRESENTED IN YOUR DEPRECIATION STUDIES.

A. I will use Account 380, Services, as an example because it is one of the largest depreciable mass accounts and represents approximately 31 percent of depreciable plant.

The retirement rate method was used to analyze the survivor characteristics of the combined property in Accounts 380, 382 and 384. Aged plant accounting data was compiled from 1962 through 2015 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1962-2015, 1996-2015 and 2006-2015 experience bands are presented on pages VII-86 through VII-97 of the report. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page

VII-86 shows $2,504,461 retired at age 0.5 with $475,196,573 exposed to retirement. Consequently, the retirement ratio is 0.0053 and the surviving ratio is 0.9947. These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 55-R0.5 on page VII-85.

The net salvage percent for Account 380, Services is presented on pages VIII-43 through VIII-45. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1962 through 2015. The 54-year period experienced $29,183,763 ($45,215 - $29,228,888) in net salvage for $80,326,586 plant retired. The result is negative net salvage of 36 percent ($29,228,888/$80,326,586). While the result was negative 36 percent, recent trends have shown indications of negative 27 percent. Therefore, based on industry ranges, historical indications and Company expectations, I determined that negative 35 percent was the most appropriate estimate for this account.

My calculation of the annual depreciation related to the original cost at March 31, 2018, of gas plant is presented on pages IX-41 through IX-43. The calculation is based on the 55-R0.5 survivor curve, 35 percent negative net salvage and the attained age. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, average life, life

expectancy and annual accrual amount and life. These totals are brought forward to the table on page VI-5.

Q. HAVE YOU CALCULATED AN ACTUAL VS. THEORETICAL RESERVE VARIANCE AS PART OF THE DEPRECIATION STUDIES?

A. Yes. As set forth on Table 4 page VI-11 of Exhibit __ (JJS-2) there is a total deficient reserve variance of $15,674,862 based on the parameters proposed as a result of the study. The reserve deficiency of $18,326,041 is set forth in Exhibit __ (JJS-1), Table 2, page I-5. The most commonly utilized method for recovering these types of excess or deficient variances is over the remaining life of each asset class. However, the remaining life method, which is widely utilized in almost all jurisdictions, is not the traditional method in New York. If remaining life recovery is not utilized, then my recommendation would be to amortize the portion of the variance above a threshold amount of 10% of the cumulative book depreciation over 20 years. I would not recommend recovery in the amortization below a 10% threshold since the reserve variance is based on a theoretical calculated amount which is subject to significant volatility as depreciation lives and net salvage rates change when applying normal depreciation practices.

Q. HAVE YOU PROPOSED RATES FOR ANY NEW ASSET CLASSES?

A. Yes. In May 2016, a software application is to be installed into Account 303.10, Miscellaneous Intangible Plant - Enterprise Software. This new

application is referred to as Barcelona. A ten-year amortization period and 10 percent rate is proposed which is the most commonly utilized recovery period for applications related to customer information systems.

VI. CONCLUSION

Q. WERE THE DEPRECIATIONS STUDIES FILED BY NATIONAL FUEL GAS DISTRIBUTION CORPORATION IN THIS PROCEEDING PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. IS THE INFORMATION CONTAINED IN THE DEPRECIATION STUDIES ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

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

Q. Do you belong to any professional societies?

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

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008 and January 2013.

Q. Please outline your experience in the field of depreciation.

A. In June, 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June, 1986 through December, 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following

companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January, 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July, 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December, 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc. and in April 2012, I was promoted to my present position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC). In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

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

Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado

Gas; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation and Greater Missouri Operations. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service

Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

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

Q. Does this conclude your qualification statement?

A. Yes.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Co.	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Co.	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Co.	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Co.	Depreciation
18.	2003	FERC	ER-03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
32.	2005	IL CC	05-	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	FERC		Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Co.	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Co.	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Co.	Depreciation
47.	2006	NC Util Cm.		Pub. Service Co. of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	ISO82, ETC. AL	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Co.	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co.-Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Co.	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Co.	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	09-	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Co.	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Co.	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Co.	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Co.	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Co.	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Co.	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Co.	Depreciation
119.	2010	IN URC		Northern Indiana Public Serv. Co. - NIFL	Depreciation
120.	2010	IN URC		Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	Lancaster, City of – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
130.	2011	Il CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Co.	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation
133.	2011	FERC	2011-2232243	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Hanover, Borough of – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	Lancaster, City of – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Co.	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
153.	2012	TX PUC		Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Co.– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Co.	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Co.	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Co. – PEPCO	Depreciation
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Co.	Depreciation
167.	2013	FERC	ER13- -0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13- -0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Co.	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14-	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Hanover, Borough of – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3370-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation

BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the
Rates, Charges, Rules and Regulations of
National Fuel Gas Distribution Corporation
for Gas Service

Case 16-G-0257

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REBUTTAL TESTIMONY OF JOHN J. SPANOS

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

September 16, 2016

Q. Please state your name and business address.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011.

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

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC as Senior Vice President.

Q. Have you previously submitted testimony in this case?

A. Yes. I provided Direct Testimony and Exhibits regarding the annual depreciation accrual rates.

Q. What is the purpose of your Rebuttal Testimony?

A. I will respond to depreciation issues proposed by the Staff Gas Panel ("Staff"). The specific issues relate to average service life and survivor curves for three accounts and the methodology used to develop the book reserve. In order to properly address these issues, I will first discuss depreciation concepts and the process of estimating service lives.

Q. Why is it important to review depreciation concepts as part of your rebuttal testimony?

A. Based on depreciation discussions in Staff's direct testimony, it is important to consider and emphasize certain fundamental depreciation concepts. In particular, it is important to highlight the

fact that the purpose of depreciation is to recover the costs of a company's assets over the actual period of time they will be in service. By allocating costs equitably over the assets' service lives, each generation of customers pays its fair share of the capital assets that provide gas service (*i.e.*, inter-generational equity). Because depreciation is a forward looking process, it necessarily involves estimates of both service lives and net salvage (net salvage is generally the cost to retire an asset). In order to provide the most equitable allocation of costs, these service life and net salvage parameters must be based on reasonable estimates that incorporate many factors, including the analysis of the Company's actual experience as well as the outlook and plans for the Company's assets (including industry paradigm changes).

Q. What is depreciation?

A. Depreciation is defined in the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA"), which has been adopted by the Commission, as follows:

> 12. Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are

> wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[1]

Q. What is the objective of depreciation?

A. The objective of depreciation is to allocate, in a systematic and rational manner, the full cost of an asset (*i.e.*, original cost less net salvage) over its service life. The USOA requires this type of allocation in General Instruction 22-A:

> Method. Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value[2] of depreciable property over the service life of the property.

Thus, the USOA confirms that depreciation represents the allocation of the full costs of a company's assets (original cost less any net salvage) over their service lives — that is, over the period of time the assets are providing service. Costs are allocated over the service lives of the assets so that customers pay for the costs of the assets that provide them service. Current customers should not pay for the costs of assets that have already been retired or those not yet in service. Similarly future customers should not have to pay for the costs of assets that are no longer in service because current customers pay too little for their service. By establishing

[1] 18 Code of Federal Regulations 101 (FERC USOA), Definition 12.
[2] The USOA defines service value as the original cost less net salvage.

appropriate depreciation rates, each generation pays the fair share of the cost of providing gas service.

Q. Please explain the process for estimating service lives.

A. Service lives are estimated in our depreciation study based on a number of factors, and these estimates incorporate accepted statistical techniques and proper judgment to determine the most reasonable estimates for each account. A depreciation study requires the estimation of events that will occur many years in the future. For example, the average service lives estimated for the Company's assets such as services and meters are 55 and 36 years, respectively. Many individual assets will live longer than the average. Thus, the depreciation study must predict what will occur over the next 55 years or more. There are tools available to aid in forecasting service lives, such as the statistical analyses of historical data. However, the Commission should not lose sight of the fact that depreciation is necessarily a forward looking process in which uncertain events are being forecast many years into the future.

Because depreciation is a process of forecasting the future, it is impossible to predict what will occur with 100 percent precision. The statistical tools available by definition consist of imperfect

information, because the Company's assets have only lived for a fraction of their lives. Therefore, estimation requires extrapolation and judgment, which must incorporate the knowledge and experience of the depreciation professional performing the study. For example, the curve fitting process for life analysis may result in a range of average service life estimates that could be supported by the historical data alone. The judgment of the depreciation professional making the estimate is required to differentiate between these possible estimates. Additionally, Company plans or other factors, including industry trends, may result in the future being different from the past. For this reason, service life estimates cannot be based only on statistical analyses of historical data.

Q. Do any authoritative depreciation texts support your assertion that a comprehensive depreciation study should incorporate factors other than statistical analysis?

A. Yes, all depreciation texts are clear that service life estimates are forecasts of future expectations. It is widely understood by depreciation professionals that sole reliance on the statistical analysis of historical data is inappropriate for life estimation.

As an example, the National Association of Regulatory Utility Commissioners *Public Utility Depreciation Practices, 1996,*

("NARUC Manual") is one of the most widely recognized authoritative depreciation texts. Chapter VIII of the NARUC Manual discusses life analysis.

Q. Does the NARUC Manual support that the statistical analysis should be the only factor used to estimate service lives?

A. No. To the contrary, the NARUC Manual is clear that "several factors should be considered in estimating property life. Some of these factors are:

1. Observable trends reflected in historical data;
2. Potential changes in the type of property installed;
3. Changes in the physical environment;
4. Changes in management requirements;
5. Changes in government requirements; and
6. Obsolescence due to the introduction of new technologies."[3]

Q. Does the NARUC Manual recognize the necessity of judgment in a depreciation study?

A. Yes. The NARUC Manual has an entire section dedicated to "informed judgment." NARUC defines "informed judgment" as:

> [A] term used to define the subjective portion of the

[3] *Public Utility Depreciation Practices*, NARUC, 1996, p. 129.

> depreciation study process. It is based on a combination of general experience, knowledge of the properties and a physical inspection, information gathered throughout the industry, and other factors which assist the analyst in making a knowledgeable estimate.[4]

NARUC also notes that "the use of informed judgment can be a major factor in forecasting" and explains that "[t]he analyst's judgment, comprised of a combination of experience and knowledge, will determine the most reasonable estimate."[5]

Q. Are Staff's recommendations set forth in its direct testimony consistent with all the concepts described above?

A. Not entirely. While Staff has used accepted statistical methods for their service life recommendations, Staff has not incorporated other important factors into its analysis. As a result, Staff's recommendations are in my view likely to result in current depreciation rates being inadequate to recover the full costs (original cost less net salvage) of the Company's assets over their service lives. Thus, future generations of customers likely will be required to pay more than their fair share if the Commission adopts Staff's depreciation recommendations. This occurs because Staff's recommended service lives are too long when placed in context of Company plans and when compared to the service lives currently

[4] *Public Utility Depreciation Practices*, NARUC, 1996, p. 128.
[5] *Ibid.*

used by other utilities.

Q. Please state in general terms why the Commission should reject Staff's proposed changes to the average service life and survivor curve estimates.

A. Staff's average service life and survivor curve estimates for 3 accounts are based primarily on the results of the statistical analyses of historical data[6], and do not appear to incorporate other important factors. By this, I mean that Staff has demonstrated little or no consideration for factors beyond the statistical analysis. It is standard industry practice to examine observable trends in historical data, the mortality characteristics of the assets being studied, individual utility plans, potential changes in types of assets being installed, changes in environment, management and governmental requirements, and obsolescence due to the introduction of new technologies. Because Staff does not appropriately consider these factors, Staff has recommended service lives for these three (3) accounts that reflect unrealistic expectations of the life characteristics for the assets studied. The service life estimates in the Company's depreciation study represent much more reasonable estimates of service life

[6] Historical data was available for the study for most accounts from 1962 to 2015.

expectations for the Company's assets.

Q. How will you address Staff's service life proposals?

A. First, I will discuss the recommendations in our depreciation study and demonstrate that these estimates are already within the range of experience for similar assets for other companies. Staff's recommendations, for these three accounts set forth longer service lives, and should be considered outliers in the industry.

I will then discuss the importance of informed judgment in service life estimation and explain that, because Staff does not appear to have completely included that critical aspect of life estimation in its analyses, Staff's approach has resulted in unreasonable and unrealistic proposals.

Q. Has the Company presented a reasonable study of the service lives of its assets?

A. Yes. The Company's depreciation study is consistent with the traditional methods used for life analysis and life estimation throughout the gas industry and across the country, and results in reasonable estimates of service life. Over its history, Gannett Fleming has performed depreciation studies in all 50 states, as well as in all ten Canadian provinces and all three Canadian territories. Based on that experience, we can provide typical ranges of service

lives experienced by others in the industry for each property account. In other words, our experience is based upon a much greater sample within the industry than a few select companies in New York that Staff utilized.

Q. How does the Company's depreciation study differ from Staff's approach?

A. Many factors were considered in the depreciation study in addition to the statistical analysis. Based on these factors, as well as knowledge of the property being studied, it would be inappropriate to select estimates based on limited factors, as it appears Staff has done. Using informed judgment, the Company's study has produced service lives that are reasonable estimates of the future experience for each account studied and the Company's estimates are better aligned with estimates in use in the gas industry.

By contrast, Staff has recommended unrealistic service life estimates because they have not incorporated the proper judgment required to perform a depreciation study. Instead, Staff focused on the results of rolling and shrinking band analyses, and has not properly considered other relevant factors that should be used to interpret the statistical studies properly.

Q. Please explain the proper process used for life estimation in the

Company's depreciation study.

A. The estimates made for the depreciation study are based on informed judgment that incorporates statistical analysis of the Company's historical data, as well as other factors. The statistical analysis used for the study is the retirement rate method,[7] which is the most commonly used and widely accepted statistical analysis of aged retirements.

Q. Is the statistical analysis the only basis for the service life estimates in the depreciation study?

A. No. While the statistical analysis is an important component of the "life analysis" process of depreciation studies, it is only one tool in determining the life characteristics that a utility's assets have experienced historically. The goal of the depreciation study is to estimate the service lives of the assets that are currently in service, not those that were retired in the past. The process is to develop informed estimates of what will happen in the future, not to simply determine what has occurred in the past and assume it will recur.

Q. Please explain further.

A. The full process of determining the service life estimates is referred to as "life estimation." Factors other than the statistical analysis

[7] The retirement rate method is described in more detail in the depreciation study filed as Exhibit ___ (JJS-2).

should always be considered, both because the historical statistical data is not always definitive (*i.e.*, often more than one survivor curve will represent a similar fit to an original life table, as usually only a "stub curve"[8] is available for the analysis) and because the historical data may not be reflective of future experience (*e.g.*, if the Company plans to replace more assets in the future than it has historically).

Q. Is judgment also an important part of the statistical analysis?

A. Yes, it is. Judgment is important for the actual statistical analysis, and in particular the curve fitting process. In particular, judgment is critical in the selection and consideration of data points, which can impact the results of the statistical analysis.

Q. Please provide an example of how the service life estimates were made in the Company's depreciation study.

A. Account 375, Structures and Improvements is a good example of how informed judgment must be incorporated into the service life estimates. For this account, there are specific reasons to expect

[8] A "stub curve" means that the original life table developed from the historical data is not a complete curve, *i.e.* it does not reach 0% surviving. Because the retirement rate method generally will only produce stub curves for many accounts, there is typically an aspect of forecasting or projecting future experience in the statistical analysis (even if no other factors are considered).

that the Company's future experience will not be the same as the Company has experienced historically. The type of building or assets that will be added to this account into the future is very different than the assets currently in the account. For the last few decades, the Company has not constructed large brick buildings for measuring and regulating stations, therefore, the future of such assets will not see as long a life as experienced historically for such account.

Q. What impact will these plans have on the service lives of structures and improvements of regulating stations?

A. The impact will be a higher rate of all the retirement units than has occurred historically. Therefore, when considering all components within the account, the average and maximum life will be getting shorter than the average and maximum life currently utilized. This, combined with the older buildings finally reaching the end of their lives, must be fully considered and factored into future expectations.

Q. In the example discussed above, you have explained how factors other than the statistical analysis should be incorporated into the informed judgment used to estimate service lives. Is informed judgment also important in the actual curve fitting process?

A. Yes. As indicated in the example discussed above, informed judgment is critical in the life estimation process. Informed judgment is also critical for the actual curve fitting process. The curve fitting process is not (nor should it be) simply an exercise in selecting mathematical or visual best fitting curves. Depending on the selection of data points and the judgment in extrapolating the survivor curve beyond the available or significant data, the curve fitting process can produce very different results. For this reason, informed judgment is critical for the proper interpretation and extrapolation of data. Staff's approach does not properly interpret the historical data.

Q. You have discussed the approach to curve fitting above. Do authoritative sources support your approach to curve fitting?

A. Yes. As an example, in *Depreciation Systems* by Wolf and Fitch the authors explain that when curve fitting the depreciation professional must "decide which points or sections of the curve should be given the most weight." Wolf and Fitch go on to explain:

> Points at the end of the curve are often based on fewer exposures and may be given less weight than points based on larger samples. The weight placed on those points will depend on the size of exposures. Often the middle section of the curve (that section ranging from approximately 80% to 20% surviving) is given more weight than the first and last sections. This middle section is relatively straight and is the

> portion of the curve that often best characterizes the survivor curve.

Wolf and Fitch also explain that curve matching should not be the only analysis performed:

> On the surface, the removal of judgment from the fitting process may appear to be an advantage, but blind acceptance of mechanical fitting processes will occasionally but consistently result in poor results. A better procedure is to use the least squares method to select candidates for the best fit. Comparison of the sum of squares will reveal situations where the difference between the best choices is small. The analyst should then visually examine the observed data and compare them to the theoretical curves. This can be done quickly on a computer with graphic capabilities so that the analyst need not use time to plot the observed curve by hand. The analyst can consider single points that contribute significantly to the sum of squares but that may deserve less weight than other points. Fits at various sections on the curve can be evaluated and weighted using the judgment of the experienced analyst.

Q. Have you followed the approach to curve fitting discussed by Wolf and Fitch?

A. Yes.

Q. Has the Staff Gas Panel agreed with all of your recommended life and salvage parameters in this case?

A. The Staff Gas Panel has agreed with all of my net salvage estimates and most of the life parameters. There were only three accounts that Staff did not agree with my estimates. The accounts were Account 367.1, Mains – Excluding Cathodic Protection;

Account 375, Structures and Improvements; and Account 376.4, Mains – Plastic.

Q. Have you conducted life analyses for all accounts utilizing the same methodology?

A. Yes.

Q. Can you illustrate the differences in estimates for Account 367.1, Mains – Excluding Cathodic Protection?

A. Yes. My life estimate is the 65-R2 survivor curve while Staff has proposed the 70-R2 survivor curve. The determination of each life estimate in the depreciation study consists of a combination of statistical analyses and informed judgment. As described on page I-4 of Exhibit JJS-2, informed judgment includes estimates of other gas utilities, the current estimate for this Company and discussions with management as to causes of retirement and future expectations of the asset class. The current estimate is a 60-H2.25 survivor curve.

In contrast, Staff's methodology was to utilize the statistical rolling and shrinking band analyses without considering any specific plans for these assets. The statistical analyses supports the R2-type curve. Staff has stated in testimony that they recommend changing to a R3 type curve, however, all exhibits support the use

of a R2 type curve.

Q. What can you conclude from Staff's testimony and exhibits regarding which type curve they are recommended for Account 367.1, Mains – Excluding Cathodic Protection?

A. Given the life estimates that Staff requested during discovery and the development of the theoretical reserve set forth in Exhibit (SGRP-7), Staff must be recommending the R2-type curve, not the R3 type curve.

Q. Do you agree with Staff's change in life parameter for Account 375.00, Structures and Improvements?

A. No. Staff states in its testimony that the life estimate of 75 year average service life was based only on rolling and shrinking band analyses. Staff's position completely ignores the currently approved estimate of 65-H2.50 as well as the Company's transition in the type of buildings being constructed in recent times. The structures in Account 375.00, Structures and Improvement, represent measuring and regulator structures which, in the early years, were constructed of brick or concrete block. In recent years, more of these Company structures are constructed of pre-fabricated steel, which simply do not have as long a life expectancy as brick or concrete block structures. These newer buildings are

constructed to fit the newly reconfigured measuring and regulating stations, which are more likely to be relocated. It should also be recognized that property units in this account include roofs, windows, doors and HVAC systems. Additionally, many of the newer assets into this account represents fencing and station barricades. These assets will have an overall shorter life cycle, therefore, the investment mix of the large brick structures and the smaller type structures being placed in service does not justify a ten-year increase in life. Also, Staff's recommended 75-R2.5 survivor curve reflects a maximum life cycle of 135 years. This is not reasonable for the type of assets in the account.

Q. Did Staff follow the same methodology for Account 376.4 Mains – Plastic as the other two accounts that were changed from your estimates?

A. No. For Account 376.4, Staff states they used the same methodology to increase life of plastic mains from 60 to 70 years, then Staff further adjusted the life another 10 years, pushing the expected average life of plastic mains out to a total of 80 years.

Q. Does Staff's process in determining the 80-year life for plastic mains follow the methodology recommended by authoritative texts and described previously in this testimony?

A. No. Staff has attempted to include additional information beyond the statistical analyses which is important, however, Staff's basis for determining the increase to 80 years ignores all the forces of retirement, and in my opinion, is unsupportable.

Q. Staff states on page 67 of its testimony that plastic will have a life as long or longer than cast iron or steel pipe. Do you agree?

A. There are no statistical analyses that support this statement. Plastic pipe has only been in service for 40 to 50 years, therefore, a full life cycle has not occurred. Thus, Staff's statement that plastic pipe is not subject to chemical reactions which cause corrosion is only one force of retirement. In fact, certain early vintage plastic mains have already been replaced, or are being targeted for replacement, for a variety of reasons. The Commission itself has recognized, in its April 17, 2015 Order Institution Proceeding For a Recovery Mechanism to Accelerate the Replacement of Leak Prone Pipe in Case 15-G-0151, that certain early vintages of plastic are considered leak prone. (Order at footnote 1). Further, Staff does not address that plastic pipe is more susceptible to dig-ins as identifying plastic pipe underground is very difficult. Plastic pipe is also more susceptible to such impingements which cause retirement. Additionally, there are other forces of retirement that

Staff does not consider when proposing an 80-year average life. These are replacements due to washouts and erosion due to weather events; relocations due to highway department, municipal utility and private construction projects; replacements due to material, component or joint failure, system improvements due to increased customer loads and reductions in local production gas supplies; low pressure system improvements in flood areas, known as storm hardening; and replacement of segments of plastic mains in conjunction with leak prone steel, cast iron and wrought iron replacements.

Q. Is it reasonable to increase lives drastically for major asset classes as Staff suggests given the high focus on system infrastructure improvements?

A. No. There is a focus industry-wide on infrastructure improvements which in itself should prevent recommendations for unnecessarily long recovery patterns of investment such as plastic pipe.

Q. Has Staff made adjustments to the depreciation reserve for the rate year?

A. Yes. Staff has attempted to adjust the forecasted depreciation expense based on a monthly calculation instead of the traditional

annual calculation commonly utilized with future rate years.

It is not reasonable to expect all projected activity, which includes closing retirement and construction work orders, to occur exactly when the asset goes into service and the associated cost of removal and gross salvage to be recorded simultaneously. Additionally, if the Company is to be required to base depreciation accruals on a monthly basis then one would have to update the depreciation accrual rate every month. These are unrealistic requirements when projecting forecasted levels of depreciation.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, at this time.

A.L.J. LECAKES: Any exhibits for Mr. Spanos?

MR. NICKSON: Yes, Your Honor. Mr. Spanos had two exhibits attached to his direct testimony which were identified as JJS1 and JJS2 and I ask that they be marked for identification.

A.L.J. LECAKES: So marked 76 for JJS1 and 77 for JJS2. That's it for the Spanos exhibits -- nothing on the rebuttal testimony?

MR. NICKSON: That is correct, Your Honor.

A.L.J. LECAKES: Okay. The next witness?

MR. NICKSON: The next witness is Michael P. Weidner. Mr. Weidner prepared testimony entitled The Direct Testimony of Michael P. Weidner which consists of 11 pages of questions and answers. Mr. Weidner also prepared testimony entitled The Rebuttal Testimony of Michael P. Weidner which consists of seven pages of questions and answers and I ask that the direct testimony and rebuttal testimony of Michael P. Weidner be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. The Weidner Direct Testimony file in the company Direct Testimony

folder should be entered now and then the Weidner Rebuttal Testimony in the company Rebuttal Testimony should follow. The affidavit will be marked as Exhibit 78.

DIRECT TESTIMONY OF MICHAEL P. WEIDNER

1 Q. Please state your name and business address.

2 A. My name is Michael P. Weidner. My business address is 6363 Main
3 Street, Williamsville, New York, 14221.

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

5 A. I am employed by National Fuel Gas Distribution Corporation
6 ("Distribution" or "the Company") in the position of Manager within the
7 Financial Accounting Department.

8 Q. Please describe your educational and employment background.

9 A. I graduated from the St. Bonaventure University, in May 1998 with a
10 Master of Business Administration Degree and Bachelor of Business
11 Administration Degree, concentrating in Accounting and Finance. In
12 September 1998, I joined Ernst & Young, LLP, as a Staff Accountant, I
13 was promoted to Senior Accountant in 2000. I have been a Certified
14 Public Accountant since December 1999.

15 I began my employment with Distribution in October 2000 in the
16 Audit Services Department. In July 2005, I transferred to the Financial
17 Accounting Department. In September 2013, I was promoted to my
18 current position.

19 Q. Please describe your responsibilities and duties in your position at
20 Distribution.

21 A. Under the general direction of the General Manager of Accounting, I am
22 responsible for the review and approval of journal entries relating to
23 Distribution's revenues and purchased gas expenses. I am also

1 responsible for the review of periodic regulatory reports to the New York
2 State Public Service Commission ("the Commission" or "PSC") and the
3 Pennsylvania Public Utility Commission. In addition, I perform various
4 functions related to the accounting consolidation of National Fuel Gas
5 Company and subsidiaries. This includes internal analyses and external
6 reporting requirements in accordance with generally accepted accounting
7 principles and Securities and Exchange Commission requirements.
8 Q. What is the purpose of your testimony in this proceeding?
9 A. I am presenting testimony and exhibits concerning historical financial data
10 and the Company's claim for Pension and OPEB cost recovery. In
11 addition, I will describe Distribution's accounting methodology for its
12 investment in gas stored underground.
13 Q. Have you previously testified before the Commission?
14 A. No.
15 Q. Are Distribution's accounts kept in accordance with the Uniform System
16 of Accounts?
17 A. Yes.
18 Q. Does Exhibit ___ (MPW-1) contain information from the books and
19 records of Distribution Corporation?
20 A. Yes.
21 Q. Please describe Exhibit ___ (MPW-1).
22 A. Exhibit ___ (MPW-1) contains information showing Distribution's financial
23 data.

1 Schedule 1, consisting of two sheets, presents the comparative
2 balance sheets, per books, of Distribution Corporation at September 30,
3 2012, 2013, 2014 and 2015.
4 Schedule 2, consisting of one sheet, presents comparative income
5 statements, per books, of the New York Division of Distribution
6 Corporation. The data shown are for the twelve months ended September
7 30, 2012, 2013, 2014 and 2015.
8 Schedule 3, consisting of one sheet, contains the statement of
9 retained earnings, per books, of Distribution Corporation for the twelve
10 months ended September 30, 2012, 2013, 2014 and 2015.
11 Schedule 4, consisting of two sheets, contains the statement of
12 gas plant in service, per books, of the New York Division of Distribution
13 Corporation at September 30, 2012, 2013, 2014 and 2015.
14 Schedule 5, consisting of one sheet, contains the statement of
15 reserve for depletion, amortization and depreciation of gas plant in
16 service, per books, for the New York Division of Distribution Corporation
17 at September 30, 2012, 2013, 2014 and 2015.
18 Schedule 6, consisting of one sheet, contains the statement of
19 operating revenues, per books, for the New York Division of Distribution
20 Corporation for the twelve months ended September 30, 2012, 2013,
21 2014 and 2015.
22 Schedule 7, consisting of six sheets, contains the statement of
23 operating and maintenance expenses, per books, for the New York

1 Division of Distribution Corporation for the twelve months ended
2 September 30, 2012, 2013, 2014 and 2015.
3 Schedule 8, consisting of one sheet, contains the statement of
4 taxes charged, per books, for the New York Division of Distribution
5 Corporation for the twelve months ended September 30, 2012, 2013,
6 2014 and 2015.
7 Schedule 9, consisting of two sheets, contains a statement of
8 operating revenues per thousand cubic feet of gas sold for the twelve
9 months ended September 2012, 2013, 2014 and 2015 for the New York
10 Division of Distribution Corporation. This schedule is compiled on the
11 same format as Schedule 6, Statement of Operating Revenues.
12 Gas Stored Underground
13 Q. What inventory accounting method does Distribution utilize?
14 A. Distribution uses the last-in, first-out ("LIFO") method of valuing inventory,
15 applied on an annual basis. Under the LIFO method, the last unit
16 purchased for inventory is the first to be sold from inventory. On a
17 monthly basis, injections and withdrawals are priced according to the
18 methodology prescribed by the Joint Proposal in Case 00-G-1858 as
19 approved by the Commission on Page 11 of the Order issued in that case
20 on April 18, 2002 and effective May 1, 2002. According to that
21 methodology, during an injection cycle, storage injections and
22 withdrawals are priced at the average commodity cost of gas purchased
23 for the month. During the withdrawal cycle, storage injections and

withdrawals are priced at the weighted average commodity cost of gas calculated over the previous injection cycle.

Q. What is the effect of Distribution valuing inventory on a historical layer basis but using an average purchased gas cost rate for injections and withdrawals?

A. Because Distribution prices injections and withdrawals at the average purchased gas cost rate for each period, the result is that, at the end of the storage withdrawal cycle in March, the cost of gas charged to customers from storage exceeds the LIFO value of that gas. In accordance with the Uniform System of Accounts and generally accepted accounting principles, Distribution records, on its books, a deferred credit (Reserve for Gas Replacement) for the difference between the amount expensed and the inventory value. The basis for recording a deferred credit to the Reserve for Gas Replacement is that it is expected that storage gas quantities withdrawn and sold will be restored by September 30. The deferred credit is eliminated as gas is injected into storage, and the layers are restored at the original LIFO cost. For example, assume the LIFO layer price of gas withdrawn from storage during the withdrawal cycle is $1.00 and the average commodity cost of gas over the previous injection cycle is $4.00. The monthly gas supply rate charged to customers includes the $4.00 cost of gas withdrawn from storage. The difference between what is included in the monthly gas supply rate ($4.00) and the LIFO layer cost ($1.00) is $3.00 ($4.00 – $1.00) and is

1 recorded in the Reserve for Gas Replacement. Continuing with this
2 example, assume during the subsequent injection cycle the Company
3 purchases gas for $4.00 to be injected into storage. Under the LIFO
4 method utilized by the Company, the cost of gas in inventory would be
5 valued at $1.00 and the Reserve for Gas Replacement would be reduced
6 by $3.00. [The withdrawal cycle is normally November - March, and the
7 injection cycle is April - October.] The balance of the Reserve for Gas
8 Replacement is included in the valuation of storage inventory Effective
9 with Case 07-G-0141 Order dated December 21, 2007 Storage Inventory
10 was removed from base rates and was included in the Merchant Function
11 Charge (Tariff Leaf 148.8).
12 Q. Please describe the investment in gas stored underground that
13 Distribution is including in the Merchant Function Charge ("MFC") and
14 how it has been determined.
15 A. The claim included in the MFC for Distribution's investment is $7,711,365
16 as shown on Exhibit ____ (MPW-2), Schedule 1. This amount was
17 computed in the following steps:
18 1. The estimated injections, withdrawals and storage balance, in Mcf
19 of gas, shown in columns A and B were obtained from the most recent
20 forecast prepared by Distribution's gas planning department.
21 Column C represents the monthly dollar value change in the month-end
22 inventory balances shown in column F.

3. The estimated monthly storage injection/withdrawal rates are shown in column D. These rates were provided by the latest forecast from the Rates and Regulatory Affairs Department as explained in Mr. Barber's testimony.

4. Column F represents the cumulative inventory balance in dollars. It is calculated as the product of column B and column D, added to the inventory balance, in dollars, from the previous month, with the single exception of the month of September. In September, the inventory balance, in dollars, is adjusted to the LIFO value of inventory remaining at September 30 (see column J for LIFO value and columns E and G for adjustment needed at year-end to calculate the LIFO value). The thirteen monthly storage gas amounts, in dollars, from Column H were averaged to calculate the underground gas in storage investment amount of $7,711,365.

5. Column J represents the LIFO value of inventory at each time period and Column I represents the Reserve for Gas Replacement, calculated as the difference between Column J and Column F. The calculation of underground gas in storage investment is directly related to anticipated prices of natural gas in the market. Since this price can be very volatile, the calculation of storage inventory can also fluctuate in a volatile manner. As can be seen from column D of Exhibit__ (MPW-2), the current expectation is for the market price of gas from the 2017 injection season (to be used in the 2017-2018 withdrawal season) to be

1 an average price of $2.5151 / Mcf. This expected price may change
2 during the pendency of the filing and will be updated for any material
3 change.
4 Pension and Post-retirement Benefits (OPEBs)
5 Q. Please describe Sheet 1 of Schedule 1 from Exhibit__ (MPW-3).
6 A. Sheet 1 calculates the projected rate allowance for Pension
7 Expense for the Rate Year. The requested rate allowance is based upon
8 the latest known projections of expense as calculated using the
9 methodology as set forth in the Accounting Standards Codification
10 ("ASC") No. 715 (formerly known as Statement of Financial Accounting
11 Standards No. 87 – Employers' Accounting for Pension (herein referred to
12 as "FAS 87")). The Company's actuary calculates the FAS 87 expense
13 each fiscal year and has provided the Company with a projection of that
14 expense for Fiscal 2017 and 2018 (the twelve months ending September
15 2017 and 2018, respectively). To calculate the Rate Year allowance, I
16 have taken six months of Fiscal 2017's estimate and six months of Fiscal
17 2018's estimate to calculate the Rate Year allowance of $22,782,410
18 (rounded to $22,782,000). I then multiplied the allowance by the O&M
19 Benefit Percentage of 65.81% (refer to testimony from Mr. Barber) to
20 calculate the Rate Year expense of $14,993,000.
21 Next, I calculated the balance in the deferral accounts at the
22 beginning of the Rate Year. Distribution is subject to the "Statement of
23 Policy and Order Concerning the Accounting and Ratemaking Treatment

1 for Pensions and Postretirement Benefits Other than Pensions" issued on
2 September 7, 1993 in Case 91-M-0890 ("Policy Statement"). Therefore,
3 Distribution is required to defer the variance between the rate allowance
4 and the FAS expense and also the variance due to a difference in sales
5 volumes between the forecasted and the actual sales amount. These
6 variances are booked to deferral accounts that need to be brought to
7 zero. The method to bring them to zero is to include the balances of the
8 deferral accounts in the future rate allowance. I have calculated that the
9 balance in the Pension deferral accounts will be $1,570,821 (this includes
10 $4,795,886 of accumulated interest income on the pension internal
11 reserve) at the beginning of the Rate Year. The accumulated interest
12 income on the pension internal reserve (as a result of Distribution's
13 contributions exceeding rate allowance) was recorded as dictated by the
14 terms of Joint Proposal associated with Case 04-G-1047 and the Rate
15 Order associated with Case 07-G-0141. I have amortized the Pension
16 deferral balance of $1,570,821 over four years, consistent with the
17 amortization period used in the last rate settlement (Case 13-G-0136), for
18 an addition to the rate allowance of $393,000 ($1,198,000 related to the
19 amortization of accumulated interest income on the pension internal
20 reserve less $(805,000) related to the other Pension deferral accounts).
21 This brings the rate allowance to $15,386,000 ($14,993,000 plus
22 $(805,000) plus $1,198,000). Given the fact that $1,198,000 of this rate
23 allowance number is due to the amortization of interest income that was

accumulated due to prior year contributions in excess of rate allowance, the $1,198,000 should not be treated as an amount to be contributed. That is, only $21,977,000 ($22,782,000 of rounded rate year pensions less $805,000 of estimated over recovery prior to rate year per Policy Statement) should be contributed in the Rate Year and succeeding rate years until rates are re-set.

Q. Please describe Sheet 2 of Schedule 1 from Exhibit__ (MPW-3).

A. Sheet 2 calculates the projected rate allowance for OPEBs for the Rate Year. The rate allowance is based upon the latest know projection of expense as calculated using the methodology as set forth in ASC 715 (formerly known as Statement of Financial Accounting Standards No. 106 – Employers' Accounting for Postretirement Benefits Other Than Pensions (herein referred to as "FAS 106"). The Company's actuary calculates the FAS 106 expense for each fiscal year and has provided the Company with a projection of that expense for Fiscal 2017 and 2018. To calculate the Rate Year allowance, I have taken six months of Fiscal 2017's estimate and six months of 2018's estimate to calculate the Rate Year allowance of $4,353,169 (rounded to $4,353,000). I then multiplied the allowance by the O&M Benefit Percentage of 65.81% (refer to testimony from Mr. Barber) to calculate the Rate Year expense of $2,865,000.

Case 16-G-0257 Rebuttal Testimony of Michael P. Weidner

Q. Please state your name and business address.

A. My name is Michael P. Weidner. My business address is 6363 Main Street, Williamsville, New York, 14221.

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

A. I am employed by National Fuel Gas Distribution Corporation ("Distribution" or "the Company") in the position of Manager within the Financial Accounting Department.

Q. Have you testified previously in this case?

A. Yes. I provided Direct Testimony, Exhibits and workpapers concerning historical financial data and the Company's claim for Pension and OPEB cost recovery. In addition, I described Distribution's accounting methodology for its investment in gas stored underground.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to update the Company's claim for its Pension and OPEB cost recovery.

Q. What is the basis for the update?

A. There are three updates. First, the O&M expense percentage of 65.81% that was initially developed by Company witness Barber has

now changed to 58.30%. This is more fully outlined Mr. Barber's Rebuttal Testimony.

Second, certain assumptions underlying the development of the Company's projections of expense calculated using the methodology as set forth in the Accounting Standards Codifications ("ASC") No. 715 (formerly known as Statement of Financial Accounting Standards No. 87 – Employers' Accounting for Pension (herein referred to as "FAS 87") and Statement of Financial Accounting Standards No. 106 – Employers' Accounting for Postretirement Benefits Other Than Pension (herein referred to as "FAS 106") have changed since the measurement date (September 30, 2015) used in the development of cost recovery noted in my Direct Testimony (Exhibit ___(MPW_3) Schedule 1 Sheets 1 and 2.

Q. What has changed in the assumptions and what is the impact?

A. The discount rates for the plans decreased by 75 basis points between September 30, 2015 and June 30, 2016. In addition, the assumed long-term rate of return on assets decreased by 25 basis points. These decreases have the effect of increasing FAS 87 and FAS 106 expense. These changes are a result of updated capital

market conditions and expectations after consultation with the Company's actuary. The Company's actuary revised its FAS 87 and FAS 106 projections based on these updates.

Q. What are the results of these changes and the change of the O&M percent?

A. As a result of the updates, the Rate Year Allowance for Pensions (Exhibit ___(MPW-4) Schedule 1Sheet 1) is $26,943,370 (rounded to $26,943,000) and the Rate Year Allowance for OPEBs (Exhibit ___(MPW-4) Schedule 1 Sheet 2) is $6,713,822 (rounded to $6,714,000). After applying the updated O&M percentage of 58.30%, the Pension and OPEB Rate Allowances become $15,708,000 and $3,914,000, respectively (after rounding). These represent upward adjustments of $715,000 (Pension) and $1,049,000 (OPEBs) from the initial filed for $14,993,000 for Pensions and $2,865,000 for OPEBs as shown in Exhibit ___(MPW-3) Schedule 1Sheets 1 and 2, respectively (after rounding).

Q. Please describe your third update.

A. In accordance with the statement of policy in Case 91-M-0890, In the Matter of the Development of a Statement of Policy Concerning the

Accounting and Ratemaking Treatment of Pensions and Postretirement Benefits Other than Pension (herein referred to as "Policy Statement"), Distribution defers the differences between the rate allowance and the FAS expense. In Exhibit ___(MPW-3) Schedule 1 Sheets 1 and 2, the original forecast of Over Recovery did not include the impact of amortization from the trial balance date of December 31, 2015 through March 31, 2017, which was allowed for in the settlement of Case 13-G-0136. This had the effect of overstating the deferral and overall Pension and OPEB cost recovery. The actual deferral balances have been updated through the trial balance date of July 31, 2016. In addition, the deferral balances include forecasted activity (which includes the aforementioned impact of amortization from the trial balance date of July 31, 2016 through March 31, 2017) along with the changes to FAS 87 and FAS 106 (discussed above) from July 31, 2016 through March 31, 2017. As a result, the Amortization of Estimated Under Recovery Prior to Rate Year per Policy Statement is now $(1,024,000) for Pensions and $(1,825,000) for OPEBs. These represent downward adjustments of $(219,000) for Pensions and $(294,000) for OPEBs from the filed for

deferral amortizations of $(805,000) for Pensions and $(1,531,000) for OPEBs as shown in Exhibit __(MPW_3) Schedule 1 Sheets 1 and 2. There was no change to the Amortization of A/C 182353 Internal Reserve-Accrued Income-Pension.

Q. Please discuss the deferral amortizations.

A. Staff witness, Mr. Davi, states on page 11 that he has "no opinion on the pre-rate year pension and OPEBs deferral balances." He goes on to state that "the pension and OPEB deferral balances are not audited in full at this time and remain open for further review and adjustment. As a result, Staff reserves the right to complete its review of the pension and OPEBs deferral at a later date, using the traditional deferral audit and review process, and will inform the Company on any areas of disagreement. The final disposition will be at the Company's next rate proceeding." He then goes on to state that "my review will begin with deferral activity beginning with the rate year ending December 31, 2008".

Q. Do you agree with Mr. Davi as it pertains to the future audit of deferral balances with the beginning point, subject to Staff's review and adjustment, is the beginning of the rate year ending December 31,

2008?

A. No. In the Case 13-G-0136, the Order Adopting Terms of Joint Proposal and Establishing Rate Plan, it states on pages 17- 18, “The Joint Proposal expressly provides that all August 2013 deferral balances remain subject to audit and open for further review….and would be subject to disposition in the Company’s next rate proceeding”.

Q. Did Mr. Davi make any adjustments to the August 2013 balances included in the Joint Proposal?

A. No he did not.

Q. Is this docket, 16-G-0257 the Company’s next rate proceeding after Case 13-G-0136?

A. Yes it is.

Q, Did Mr. Davi follow the requirement in the 13-G-0136 Order?

A. Mr. Davi did not and now claims that the balances should continue to remain subject to audit and open for further review and adjustment subject to the Company’s next rate case. This is in violation of the 13-G-0136 Order. Staff had two full years to comply with the 13-G-0136 Order and should not be given the ability to audit the deferral

balances prior to the 13-G-0136 Order.

Q. What is your recommendation?

A. The beginning point of any audit of deferral balances for Pension and OPEBs would be September 1, 2013, which is consistent with the language in the 13-G-0136 Order.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, at this time.

1 Next, I calculated the balance in the deferral accounts at the
2 beginning of the Rate Year. As mentioned previously, Distribution is
3 subject to the Policy Statement and therefore is required to defer the
4 variance between the rate allowance and the FAS 106 expense and also
5 the variance due to a difference in volumes between the forecast and
6 actual. These variances are booked to deferral accounts that need to be
7 brought to zero. The method to bring to zero is to include the balances of
8 the deferral accounts in the future rate allowance. I have calculated the
9 balance in the OPEB deferral accounts will be $(6,124,905). I have
10 amortized this balance over four years, consistent with the last rate
11 settlement (Case 13-G-0136), for a reduction to the rate allowance of
12 $1,531,000. This brings the rate allowance for OPEBs to $1,334,000.
13 Q. Are you familiar with the Affiliate Rules adopted in Case 04-G-1047 and is
14 your department compliant with these rules?
15 A. Yes, I am familiar with these rules and the Financial Accounting
16 Department is compliant with these rules. All Distribution transactions
17 with its affiliates, including those involving goods and services, are
18 conducted in accordance with these rules.
19 Q. Does this conclude your testimony at this time?
20 A. Yes.

A.L.J. LECAKES: And Mr. Weidner's exhibits?

MR. NICKSON: Attached to the direct testimony of Mr. Weidner are three exhibits, MPW-1 through MPW-3, and attached to the rebuttal testimony of Mr. Weidner is one exhibit, MPW-4, and I ask that each of those be marked for identification.

A.L.J. LECAKES: Exhibit pre-marked as MPW-1 will now be 79, MPW-2 Exhibit 80, MPW3 Exhibit 81. The MPW4 with the rebuttal testimony will be marked as Exhibit 82. Next witness?

MR. NICKSON: The next witness is a panel, Your Honor. It's the company finance panel which consists of David Bauer, Timothy Silverstein, and Jodi Smith.

The Company Finance Panel prepared testimony entitled The Rebuttal Testimony of the Company Finance Panel which consists of 32 pages of questions and answers.

The Company Finance Panel also prepared supplemental testimony entitled The Supplemental Testimony of the Company Finance Panel which consists of three pages of questions and answers. I ask that the rebuttal and supplemental testimony of The Company Finance

Panel be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. At this point in the record the file Company Finance Panel Rebuttal Testimony in the company Rebuttal Testimony should be put in and then in the folder of the 9/30/2016 Company Supplemental Testimony the Company Finance Panel Supplemental Testimony should be offered. The affidavit will be marked as Exhibit 83.

Case 16-G-0257 Rebuttal Testimony of the Company Finance Panel

Q. Please state the names of the members of the Company Finance Panel ("CFP").

A. We are David P. Bauer, Timothy J. Silverstein, and Jodi J. Smith.

Q. Please state your business address.

A. Our business address is 6363 Main Street, Williamsville, NY 14221.

Q. Mr. Bauer, please describe your current position and responsibilities.

A. I am Treasurer of National Fuel Gas Distribution Corporation ("Distribution" or "the Company"). In addition, I am Treasurer and Principal Financial Officer of National Fuel Gas Company ("NFG" or "the Parent"), Distribution's parent.

Q. Please describe your education, professional background and work experience.

A. I graduated from Boston College in 1991 with a Bachelor's degree in Accounting. I have been employed by National Fuel since 2001.

Q. Have you testified before the NY PSC before?

A. Yes, I have testified in two prior cases for Distribution: 04-G-1047 and 07-G-0141.

Q. Mr. Silverstein, by whom are you employed and in what capacity?

A. I am employed by Distribution as a Director in the Finance

Department.

Q. Please state briefly your educational and professional experience.

A. I graduated from the State University of New York at Buffalo in 2005 with a Bachelor of Science degree in Computer Engineering and again in 2008 with a Masters of Business Administration. Shortly after receiving my Bachelor's degree, I worked for HSBC Bank as an Analyst in its Global Data Center. In 2008, I joined Distribution as a Management Associate. In 2010, I was promoted to Director of Investor Relations and transferred into the Finance Department in 2014 as a Senior Financial Analyst. In March 2016, I was promoted to Director within the Finance Department.

Q. Have you testified previously in this case?

A. No. This will be the first time testifying in this case or any other regulatory proceeding.

Q. Ms. Smith, by whom are you employed and in what capacity?

A. My credentials are listed in the Direct Testimony I provided along with Exhibits and workpapers regarding the actual and projected capitalization ratios, debt cost rates, and the sources and uses of funds for NFG.

Q. What is the overall purpose of your rebuttal testimony?

A. We will respond to the recommended capital structure and cost of long-term debt underpinning the establishment of a fair rate of return that will be used to determine the revenue requirement for the rate year ending March 31, 2018, as presented in the Direct Testimony of the New York State Department of Public Service Staff Finance Panel ("Staff"). In this context, we will explain the circumstances that led to the impairment charges taken by the Parent, demonstrate that the so-called "ring-fencing" provisions recommended by Staff are unwarranted, unnecessary, and likely very costly to implement, and explain how Distribution is fully protected from adverse consequences flowing from the impairment charges taken by NFG. We will, moreover, show a simple step or steps that can be taken to alleviate any perceived Staff concerns and that further support the appropriate 48% equity ratio initially requested by Distribution for ratemaking purposes.

Q. Does your testimony rely on interrogatory responses (IRs) provided by Staff?

A. Yes. These IRs are included as Exhibit_(CFP-1) and Exhibit_(CFP-

2).

Q. Are you sponsoring other exhibits?

A. Yes. We are sponsoring 9 exhibits in total, identified as Exhibit_(CFP-1) through Exhibit_(CFP-9).

Summary

Q. Please provide a summary of your rebuttal testimony and how it differs from Staff's Direct Testimony.

A. Staff's testimony presents a case, fraught with misunderstanding, that sets out to "establish a fair rate of return (ROR) that will be used to determine the revenue requirement of National Fuel Gas Distribution Corporation…" In presenting their case, Staff's arguments in support of their recommended capital structure and ring-fencing provisions demonstrate a fundamental lack of understanding of the Parent's other rate-regulated and non-rate-regulated businesses and certain accounting rules that are arbitrary in nature and do not accurately portray the ongoing profitability and stability of NFG. Furthermore, they substantially overstate, and in some instances plainly misstate, the significance that the credit rating agencies place on book capital

structure when evaluating a company's credit rating. These two issues are the crux of their argument for recommending a historically low common equity ratio and the inaccurate portrayal of a company on the verge of financial instability that mandates the need for overreaching ring-fencing provisions.

This testimony is structured in three major sections. First, we will address the Parent's capital structure, why certain arbitrary accounting rules have temporarily reduced its overall common equity ratio, and how little rating agencies and other major stakeholders rely on capital structure in the evaluation of a company's overall risk and financial stability. Second, we will allay Staff's concerns that the Company's projected cost of debt was "exceptionally high" when Direct Testimony was originally constructed in April 2016. That acts as the foundation of their argument for significant ring-fencing provisions and, as we will demonstrate, our cost of debt today is reasonable and in line with Staff's expectations. Lastly, we will review the ring-fencing provisions proposed by Staff, along with measures that the Company has already established that we believe effectively

insulate Distribution and its ratepayers from Staff's perceived risks at the Parent.

Capital Structure / Impairments

Q. Please discuss how Staff determined its proposed common equity ratio to be utilized in this proceeding?

A. Staff is recommending that the common equity ratio used to determine a fair rate of return for Distribution ought not exceed the consolidated common equity ratio for the Parent, which as of June 30, 2016 Staff calculated as 42.3%. They also recommend that this number should be updated at the time of the Commission's decision to best reflect the actual mix of capital during the rate year.

Q. Do you agree with Staff's recommendation?

A. No. The Parent's capital structure has been significantly influenced by U.S. Securities and Exchange Commission ("SEC") accounting rules for oil and gas activities. Over the past six quarters, those rules have required the Parent to record significant non-cash write-downs to the value of its exploration and production related assets, which in turn has led to a drop in the Parent's common equity ratio. As we will demonstrate, and as the SEC acknowledges, these rules require the

use of arbitrary assumptions that do not necessarily reflect the underlying fundamentals of the business. As a result, the Parent's equity component is not relevant for setting Distribution's rates.

Q. Please describe how the SEC rules impact the Parent's accounting for oil and gas activities?

A. The Parent accounts for its exploration and production activities using the "full cost" method of accounting. A key element of the full cost accounting method is the use of a "ceiling test" calculation that is performed at each quarter end. In simple terms, the ceiling test compares the present value (using a 10% discount rate) of expected future net revenue from a company's oil and natural gas reserves with the net book value of its assets adjusted for deferred income taxes. To the extent the expected future net revenue is below the carrying cost of the assets, an impairment is recorded to write down the value of the assets. See Exhibit _(CFP-3) for the SEC's interpretation of revisions to its rules regarding oil and gas accounting and ceiling test impairment calculations and Exhibit_(CFP-4) which contains the financial accounting and reporting guidelines for oil and

gas producing activities as specified by SEC Regulation S-X, Article 4, Rule 4-10.

Q. Is there anything unique about the ceiling test calculation?

A. While on the surface the ceiling test calculation appears consistent with typical asset impairment tests, certain SEC-mandated inputs to the calculation of future net revenue are arbitrary in nature and can have a dramatic impact on the results of the calculation. For example, the discount rate used to calculate the present value of expected future net revenue is set at an arbitrary 10% so that it is consistent among all companies that apply full cost accounting. In contrast, most asset impairment calculations contained in other areas of the accounting literature determine the present value of future cash flows using a discount rate that is tied to that specific enterprise's cost of capital.

In addition, the pricing assumptions used to estimate future net revenue are also rather arbitrary. Unlike traditional asset impairment calculations that generally use forward-looking assumptions, the full cost rules require that a company's reserves be valued using a price

equal to the average first day of the month pricing from the prior twelve months.

Q. Are there any cash flow impacts from a ceiling test impairment charge?

A. No, a ceiling test impairment charge has no cash flows associated with it. It is simply a backward looking accounting adjustment that uses twelve month historical prices. The future net revenue the Parent actually receives will obviously reflect the future pricing environment, not historical prices.

Q. Does the SEC provide a rationale for using these various pricing and discount rate assumptions?

A. In its explanation of the oil and gas reporting requirements included in Exhibit_(CFP-3), the SEC states:

> "The objective of reserves estimation is to provide the public with comparable information about volumes, not fair value, of a company's reserves available to enable investors to compare the business prospects of different companies … if the objective of reserve disclosures were to provide fair value information, we believe a pricing system that incorporates

assumptions about estimated future market prices and costs related to extraction could be a more appropriate basis for estimation."

Clearly, the SEC's intent is to ensure comparability across the industry, and not to determine the fair value of the assets. As a result, at a given point in time, an exploration and production company's balance sheet may diverge from the economic fundamentals underlying the business.

Q. What was the prior twelve month pricing that the SEC required to be used in the most recent calculation of the Parent's impairment of oil and gas producing properties?

A. For the quarter ended June 30, 2016, the SEC rules required the Parent to utilize the average natural gas and crude oil prices over the previous twelve months. As a result, the estimate of future net revenue was based on a Henry Hub natural gas price of $2.24 per MMBTU and a West Texas Intermediate ("WTI") crude oil price of $41.91 per barrel, both calculated over the period from July 2015 through June 2016.

Q. At June 30, 2016, when the Parent's last impairment of oil and gas producing properties was recorded, what were NYMEX natural gas and crude oil future prices?

A. As of June 30, 2016, the future estimated price of Henry Hub was $3.075 per MMBTU and the future estimated price of WTI was $52.75 per barrel. These prices were higher than the historical pricing required in calculating the potential ceiling test impairment as of June 30, 2016 by $0.835 per MMBTU and $10.84 per barrel, or 37% and 26%, respectively.

Q. At a Henry Hub price of $3.075 per MMBTU and a WTI price of $52.75 per barrel, would the Parent have recorded a ceiling test impairment for the quarter ended June 30, 2016?

A. No, at those prices, the value of the Parent's oil and gas reserves would have significantly exceeded the carrying value of its oil and gas assets, also known as a ceiling test "cushion".

Q. If there is a ceiling test "cushion", can the value of the Parent's assets be written up to reflect current pricing?

A. No, the ceiling test required by the SEC is a one-way street. Over time, both current and retained earnings will benefit from the

improved commodity prices (and lower depletion expense given the lower asset base post impairments), but, because of the long-lived nature of oil and gas assets, it takes many years for that recovery to be fully reflected in the capital structure. As a result, in periods of volatility in commodity prices, the value of an oil and gas company's assets as calculated under the full cost method of accounting (and consequently the common equity component of its capital structure) may deviate significantly from economic reality.

Q. Hypothetically, if the SEC permitted the Parent to write up the value of its oil and gas producing properties to reflect current prices, how would that change the Parent's capital structure?

A. If the SEC permitted the Parent to write up the value of its oil and gas assets to reflect the forward-looking prices discussed above (Henry Hub: $3.075/MMBTU; WTI: $52.75/Barrel) instead of the trailing twelve month average pricing, the result would be a significant benefit to the Parent's equity ratio. We estimate that such an adjustment would increase equity approximately $400 million and improve the Parent's equity ratio to 47.9% as of June 30, 2016. See Exhibit_(CFP-5) for the revised summary of the ceiling test

calculation and for the revised calculation of the Parent's capital structure.

Q. Are there other methods of accounting for oil and gas activities and do they produce different results?

A. Yes, the SEC also permits companies to use the "successful efforts" method of accounting. While there are several differences between full cost and successful efforts, for purposes of this discussion, the most significant difference is in the calculation of asset impairments - under successful efforts, companies may use forward looking prices when estimating future cash flows.

Utilizing the successful efforts method instead of the full cost accounting method can produce meaningfully different accounting results, which can have a dramatic impact on a company's common equity ratio.

One recent example, included in Exhibit_(CFP-6), is Apache Corporation which for its March 31, 2016 financial statements, switched from full cost to successful efforts. As part of the conversion, Apache restated their financial statements to reflect the successful efforts method of accounting, and in the process, "created"

an additional $5.3 billion in retained earnings. The underlying fundamentals of the industry and their business did not change, but a simple change in the accounting method led to a significant 69% improvement in their retained earnings, and therefore the common equity component of their capital structure. This is not to suggest that NFG's equity would increase by a similar amount, but rather an illustration of the arbitrary nature of oil and gas accounting – two different accounting methods, both approved by the SEC, produced dramatically different results. This disparity further supports our view that the Parent's capital structure is simply an inappropriate measure for use in setting Distribution's rates.

Q. In several places in their testimony, Staff goes to great lengths to portray what they see as the financial and other consequences of the ceiling test impairments. In particular, they emphasize the importance of capital structure to the analysis performed by credit rating agencies. Do you agree with their conclusions?

A. No, in our experience, neither S&P nor Moody's uses current or expected capital structure as a significant factor in their evaluations of the Parent's credit rating. As Staff points out at Exhibit__(FP-7),

Moody's focuses on four major areas in its assessment of credit risk: regulatory framework (25%), ability to recover costs and earn returns (25%), diversification (10%), and financial strength/key financial metrics (40%). Debt/Capitalization is a subcategory within Moody's "key financial metrics" but its total weighting in the overall analysis is very small at 7.5%.

When analyzing cash flow and leverage, S&P follows its Corporate Methodology and supplemental Ratios and Adjustments guidelines, included as Exhibit_(CFP-7) and Exhibit_(CFP-8), respectively, which utilize two core credit ratios and five supplemental ratios, explained on pages 30-31 of the Corporate Methodology. The two core ratios S&P utilizes, both of which are driven by cash flow, are: Funds from Operations ("FFO")/Debt and Debt/Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA"). Neither the core nor supplemental ratios include the Debt/Capital ratio cited by Staff as a key component of S&P's assessment of financial risk.

In the ratings process, S&P may modify a company's overall risk based on a number of different items, one of which is capital structure. However, when S&P evaluates capital structure, they

focus on four specific topics: currency risk associated with debt, debt maturity profile, interest rate risk associated with debt, and investments. None of these items include an evaluation of the book debt or equity to total capital ratios.

Q. Staff includes Exhibit__(FP-6) in an attempt to demonstrate that S&P and Moody's would determine that Distribution's credit rating would be higher than the Parent. Do you agree with this analysis?

A. No, we do not, as this approach contains several major flaws:

- Staff's entire analysis in this exhibit is based upon an assumption that their recommended revenue requirement of $1.882 million will be adopted, as opposed to Distribution's request of $41.697 million. Staff's approach is somewhat circular in that they assume their draconian view on Distribution's revenue requirement, which then flows through their analysis. Assuming both approaches to evaluating credit ratings were reasonable, which we will demonstrate they are not, using a dramatically different revenue requirement leads to a different outcome in the analysis.

- For its analysis of S&P's approach to evaluating the theoretical business and financial risk of Distribution, Staff relies on a report issued by S&P on September 18, 2012 titled, "Methodology: Business Risk/Financial Risk Matrix Expanded". Included as the first paragraph to this report is the following:

> "Editor's Note: We originally published this criteria article on Sept. 18, 2012. We're republishing it following our periodic review completed on August 21, 2015. This article has been partially superseded by the article titled, "Corporate Methodology," published on Nov. 19, 2013, for issuers within the scope of that criteria, but remains in effect for the following sectors or entities: project developers, transportation equipment leasing, auto rentals, investment holding companies and companies that maximize their returns by buying and selling equity holdings over time, corporate securitizations, and other entities whose cash flows are primarily derived from partially owned equity holdings."

It is clear, based on the "Editor's Note" in the report that this methodology has been superseded by S&P's Corporate Methodology which we previously discussed and included in Exhibit__(CFP-7). As a result, Staff's analysis cannot be relied upon since the methodology has evolved and this approach is no longer used by S&P to evaluate the credit rating of a utility. When comparing this dated methodology

with their current methodology, the key difference is that S&P no longer include debt/capital as a key financial metric.

- Staff's attempt to recreate Moody's analysis focuses on the four major financial criteria to evaluate a company's rating. What they fail to capture is that this approach only represents 40% of their overall analysis and Staff fails to place any consideration on the evaluation of the non-financial factors that make up 60% of Moody's credit analysis of regulated utilities.

Q. Do you agree with Staff's statement that "rating agencies in whole and in part, base their utility ratings on the parent company's capital structure"?

A. No, Staff's statement has tremendously overstated the importance of capital structure in the credit rating process. Based on the aforementioned review of the rating methodologies for both S&P and Moody's, there is limited emphasis placed on a company's capital structure in the ratings process. In fact, in their most recent credit opinions on NFG, neither firm has included a discussion of either ceiling test impairments or the Parent's capital structure. The only mention of the Parent's capital structure is by Moody's when it states

the details of a covenant contained in the Parent's committed credit facility. See Staff Exhibit__(FP-8) and Exhibit__(FP-10) for Moody's and S&P's most recent credit opinions, respectively.

Q. In their testimony, Staff states: "it is a long-established policy of the Commission to use the consolidated capital structure when setting rates of an affiliated utility company, and there are no compelling reasons to deviate from this policy in this case." Do you agree with their statement?

A. No. As Staff states in their interrogatory response, which is included in Exhibit_(CFP-1), "All the current rate plans for the major gas and electric utilities in NYS, except KeySpan Gas East Corp., currently have a 48.0% common equity ratio in the respective rate plan." It must be noted that the common equity ratio used to determine rates frequently differs from that of the actual capital structure of the entity or its parent. Based on that evidence, Staff's position that there is a long-standing policy linked to the use of the parent's consolidated capital structure is not accurate. Instead there is ample evidence, which Staff supports, that a 48.0% common equity ratio represents the ratio that the Commission has approved for all major electric and

gas utilities since 2009, with the exception of KeySpan Gas East Corp.

Q. In Distribution's most recent earnings review case, Case 13-G-0136, did Staff recommend using the Parent's capital structure?

A. No. We would note that in Distribution's earnings review case, Case 13-G-0136, Staff testified as follows: "Based on an allocated 60% equity / 40% debt subsidiary adjustment, NFG's resulting regulated capital structure reflects a 57.1% equity ratio and a 42.9% debt ratio." Case 13-G-0136 Tr.188. Staff, despite the-then 57.1% equity ratio of the Parent, testified (Case 13-G-0136, Tr. 190-192):

> Q. Describe your adjustments to the resultant regulated capital structure.
>
> A. We compared the resultant regulated capital structure relative to the capital structure of eight major electric and gas companies under the Commission's jurisdiction (the compared companies). We next made adjustments to reflect NY Distribution's S&P's risk profile relative to the average of the compared companies.
>
> Q. Please identify the compared companies.
>
> A. The compared companies are Central Hudson Gas & Electric Corporation (CHG&E), Consolidated Edison Company of New York, Inc (CECONY), KeySpan Energy Delivery – New York (KEDNY), KeySpan

Energy Delivery – Long Island (KEDLI),Niagara Mohawk Power Corporation (NMPC), Orange & Rockland Utilities, Inc. (O&R), New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E).

Q. Describe the capitalization upon which the Commission most recently set revenue requirement for the compared companies.

A. The Commission most recently determined the revenue requirement for each of the compared companies based on a 48% equity ratio, with the exception of KEDNY and KEDLI, for which the Commission set rates based on a 45% equity ratio in 2007. KEDNY recently entered into a joint proposal (Case 12-G-0544) wherein it, Staff and other parties, have agreed to determine its revenue requirement based on a 48% equity ratio.

Cost of Debt

Q. Do you agree with Staff's position that a long-term debt cost rate should be 5.62% in this case?

A. Yes. Given that the Parent's next planned debt issuance is nearly two years away and falls outside of the rate year, the actual cost of debt should reflect the Parent's embedded cost of debt today.

Q. NFG was recently downgraded by Moody's. Does this downgrade impact the embedded cost of debt reflected in the rates proposed in this rate case?

A. No, the 5.62% embedded cost of debt reflects the interest rate on issuances made prior to the downgrade. Further, as described in Witness Smith's testimony, the Parent has no plans to issue new debt during the rate year.

Q. Do you believe the Moody's downgrade changed the Parent's weighted average credit rating?

A. No, the Parent's blended credit rating after the Moody's downgrade still remains investment grade with the equivalent of a "BBB" rating. The Parent maintains ratings from three major rating agencies: S&P, Moody's and Fitch. In the instance where Moody's and S&P have divergent ratings, Fitch is colloquially referred to as the "tie-breaker."

Prior to the Moody's downgrade, the Parent had equivalent ratings from S&P and Moody's (BBB/Baa2). Subsequent to the Moody's downgrade, the Parent had a split rating from S&P and Moody's (BBB/Baa3). In instances where issuers have a split rating, investors often look to Fitch's rating to break the so-called tie. Today, Fitch's rating is BBB. Accordingly, from the perspective of

many market participants, the Company's overall rating is still equivalent to a "BBB", no different than prior to the downgrade.

Q. At page 33 of their testimony, the Staff Panel testifies "there are two issuances planned of $300 million in April 2018, and $250 million in April 2019. Both of these have exceptionally high estimated debt cost rates of 6.88%, per Distribution. This is an example of why we are recommending ring-fencing mechanisms." Do you agree with Staff's assessment of the Parent's previously expected cost of debt being "exceptionally high"?

A. Yes, however, the Parent now expects a much lower cost of debt, resulting from factors that differ from those that Staff used to support their rationale. In Company Witness Smith's testimony as filed on April 28, 2016 she stated that there is an anticipated long-term debt issuance in April 2018 that was estimated to carry a coupon rate of 6.755%. At the time her testimony was being compiled, there was a temporary dislocation in the debt capital markets that caused credit spreads to widen, not just for NFG, but for many companies in our industry.

Q. What do you believe your cost of debt is today?

A. We believe that the Company's cost of issuing 10-year long-term debt today would be approximately 4.00% plus or minus 25 basis points. This is based on the current U.S. Treasury yield on a 10-year note of 1.50%.

Q. What cost of debt does Staff feel is reasonable for 10-year debt?

A. In their interrogatory response, included in Exhibit_(CFP-2), Staff states that, "a more reasonable rate for the 10-year debt forecasts for 2018 and 2019 would be approximately 4.00% using Moody's recent corporate bond average yields for 'A' rated debt." They also go on to further state, "we believe that a better estimate of future interest rates are existing rates established by the markets." Given that we previously stated our current expectations for cost of debt on a 10-year maturity would be approximately 4.00%, based on today's 10-Year U.S. Treasury rate, we believe our cost of debt is not out of line with Staff's expectations and does not point to our current estimated rates being "exceptionally high".

Q. Staff also introduced the cost of debt from recent issuances of other New York State utilities. Do you believe these are accurate comparisons?

A. The notion that one may reliably compare debt issuances between different companies, or even the same company, at different points in time is a fallacy. Volatility in treasury rates, credit spreads, and new issue concessions can lead to materially different coupon rates for similar issuers, sometimes within weeks of each other. Furthermore, company specific factors beyond credit characteristics can impact the credit spread, making an “apples-to-apples” comparison very difficult. These factors include the size of an issuance, the frequency that a company issues new bonds, and the overall liquidity of a company’s bond portfolio.

Q. Staff is concerned with a covenant restriction that prevents the Parent from issuing new long-term debt. Do you agree with their concerns?

A. No. As described above, the Parent does not intend to issue any long-term debt during the rate year. Looking beyond the rate year, the Parent’s next long-term debt issuances are planned in April 2018 and April 2019. These issuances are re-financings of maturing debt, which are not prohibited under the covenant in question (the covenant prohibits only issuances of incremental

long-term debt). In any event, based on its current forecast, the Parent expects that covenant will no longer be an issue after the quarter ending March 31, 2017. With the last forecasted impairment anticipated to occur in the quarter ending September 30, 2016, the Parent's forecasted "Income Available for Interest" for the 12 months preceding March 31, 2017 will exceed the threshold required under the 1974 indenture.

Q. Staff raises the specter of a Parent bankruptcy throughout their testimony, implying that the Parent is financially weak and is in threat of bankruptcy. Do you agree?

A. No. As noted above, the Parent has an average credit rating of BBB, which is an investment grade rating. Further, at June 30, 2016, the Parent had $106 million of cash on its balance sheet and undrawn committed lines of credit available to it totaling $1.25 billion, of which $750 million is committed through 2019. On September 9, 2016, the Parent renewed the remaining $500 million of those lines of credit through September 8, 2017 at the same pricing as in the previous facility.

Q. How does the Parent view the importance of maintaining its investment grade credit rating?

A. National Fuel continues to maintain a stance with all stakeholders that it intends to maintain an investment grade rating. As the Parent's Chief Executive Officer, Ronald J. Tanski, has stated in previous public disclosures, including as recently as November 2015 on its fiscal 2015 fourth quarter earnings teleconference, included in Exhibit_(CFP-9):

> Analyst: "On the credit rating, would you be willing to sacrifice the credit rating?"
>
> Ronald J. Tanski: "…We have regulatory commissions that would expect us to be an investment-grade credit rating, so that would be our intent."

<u>Existing Ratepayer Protections</u>

Q. What mechanisms does the Parent have in place to protect utility assets from non-rate-regulated subsidiaries that obviate the need for Staff's "ring-fencing" restrictions on Distribution?

A. The Parent maintains a traditional Money Pool arrangement among its subsidiaries. Under that agreement, the Parent makes loans

available to its subsidiaries using the proceeds of borrowings under various borrowing facilities, including commercial paper, short-term lines of credit and revolving lines of credit. In addition, at certain times during the year, certain of its subsidiaries generate surplus funds, which they may choose to invest in the Money Pool.

The Money Pool agreement contains two important provisions that help to insulate Distribution from the Parent's other subsidiaries. First, Distribution has first priority on borrowings from the Money Pool. Second, Distribution is not permitted to invest excess cash into the Money Pool (it maintains its own bank accounts).

Q. Is the Parent considering other measures to address Staff concerns?

A. Yes, the Parent is in the process of amending the Money Pool to reserve $150 million of its committed credit facilities, solely for the benefit of Distribution. As a result, Distribution will essentially have its own dedicated credit facilities, but without the incremental costs of obtaining a separate credit rating.

Q. Staff has proposed a number of additional ring fencing mechanisms. Do you agree with these?

A. No. Staff is trying to manufacture an issue where one does not exist. The Parent has reasonable borrowing costs and adequate protections for its ratepayers. Company Witness Reed further demonstrates that Staff's proposed additional ring-fencing provisions are inappropriate for Distribution. Furthermore, implementation of one of Staff's ring-fencing proposals would run counter to the Parent's credit agreement and one of the Parent's indentures.

Q. What ring-fencing proposal would run counter to the Parent's credit agreement and 1974 indenture?

A. Staff recommends the creation of a special class of preferred stock by Distribution, to be held by a party independent of the Parent and its subsidiaries. This "golden share," as the Staff refers to it, "would prevent a bankruptcy of the parent, or any of its affiliates, from triggering a voluntary bankruptcy of Distribution." As we understand Staff's proposal, this special class of preferred stock would have determinative voting rights with respect to any voluntary bankruptcy petition proposed by Distribution.

The issuance by Distribution of a special class of preferred stock to an outside party would render untrue one of the Parent's representations and warranties set forth in its syndicated credit agreement. In particular, the Parent would not be able to represent and warrant that it owns and has the unencumbered right to vote all outstanding ownership interests in each of its material subsidiaries. Without this representation, the lenders under the credit agreement would not be obligated to make loans to the Parent. A critical component of the Parent's liquidity profile would therefore be jeopardized by the creation of the so-called "golden share".

In addition, Distribution's issuance of preferred stock to an outside party would potentially violate certain covenants in the Parent's 1974 indenture under which it has issued long-term debt. First, the same covenant that restricts the Parent's issuance of incremental long-term debt also restricts the issuance of preferred stock by Distribution and other subsidiaries of the Parent. Based on its current forecast, the Parent expects these restrictions to be in effect through March 31, 2017. Second, if the preferred stock recommended by Staff were entitled to vote in the election of

directors, then such stock would be considered "voting shares" under the indenture, and the Parent's compliance with other covenants would come into question. In particular, because the preferred stock would have an effective 100% voting right as to a particular matter (a voluntary bankruptcy petition), the Parent might no longer be considered the owner of at least 75%, or even a majority, of Distribution's voting shares, as may be required by certain covenants. Under those circumstances, the Board of Directors of the Parent could not permit Distribution to issue the preferred stock unless the Parent were able to obtain from the holders of the debt outstanding under the indenture an amendment or waiver of the covenants in question.

Q. Are there any costs associated with implementing any of the proposed ring-fencing mechanisms?

A. Yes. There would be two primary costs with implementing Staff's proposed ring-fencing mechanisms. First, given the previously discussed concerns around the "golden share" and the 1974 indenture, the Parent may be required to eliminate this indenture by delivering to its trustee cash or cash equivalents for all future

Q. Please state the names of the members of the Company Finance Panel ("CFP").

A. We are David P. Bauer, Timothy J. Silverstein, and Jodi J. Smith.

Q. Have you previously provided testimony in this proceeding?

A. Yes, Ms. Smith provided Direct Testimony and we all joined in providing Rebuttal Testimony in this proceeding.

Q. What is the overall purpose of your Supplemental Testimony?

A. We will respond to the Supplemental Testimony of the Staff Finance Panel ("Staff") in regards to capital structure and ring-fencing.

Capital Structure

Q. Based on your review of the Staff Finance Panel's (the "SFP") Supplemental Exhibit__(FP-24), do you believe the SFP has reached the correct conclusion that "the capitalization of National Fuel Gas Company is an important factor in Moody's ratings analysis of the Parent"?

A. No, the SFP appears to have inaccurately presented Moody's approach to evaluating leverage. Aside from referencing quotes from the Moody's report that are general to the E&P industry and in no way specific to National Fuel, SFP's supplemental testimony offers no

support for its assertion that book capitalization is an important factor in the ratings process. Throughout the report, it's clear that Moody's uses cash flow based metrics to assess leverage, not book capitalization. The principal metrics cited by Moody's are: "Total Debt to EBITDA;" "Net Debt to EBITDA;" "EBITDA/Interest;" and "Retained Cash Flow/Total Debt" - all of which are cash flow based metrics. Nowhere in this report does Moody's reference book capital structure as a way to assess leverage (in fact, there isn't a single reference to the term "capitalization" anywhere in the report). Staff's conclusion that book capitalization is an important factor in the ratings process is simply inaccurate.

Q. Is the approach described in Exhibit__(FP-24) consistent with your discussions with Moody's?

A. Yes. We meet with the rating agencies annually to review National Fuel Gas Company's business plans and financial forecast. During these meetings, leverage is a primary area of focus; however, book capital structure has not been a focal point. In fact, during our annual meeting with Moody's in early 2015 (which was just prior to the start of the recent ceiling test impairments), we specifically

asked whether the expected ceiling test impairment charges (and their resultant impact on our book capitalization) would impact our rating. In response, Moody's stated that book capital structure carries little to no weight in their determination of our credit rating. They indicated that expected cash flow and interest coverage based metrics were the primary ones used in their analysis. We received similar guidance from S&P and Fitch.

Q. Does this conclude your Supplemental Testimony?

A. Yes, at this time.

principal and interest payments of the $99 million in long-term debt outstanding under that indenture. Given the terms of that debt, based on today's interest rates, the Parent would be required to pay its bondholders $138.7 million to eliminate the current $99.0 million outstanding under the 1974 Indenture, leading to a net cost of $39.7 million.

Second, Distribution would need to register with the SEC, obtain its own credit ratings and short-term credit facilities. These costs would likely be in excess of $1.2 million.

Combined, these costs would be significant, totaling more than $40 million, and would need to be recovered from ratepayers.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, at this time.

A.L.J. LECAKES: The exhibits attached to either Finance Panel testimony?

MR. NICKSON: There are nine exhibits attached to the rebuttal testimony of The Company Finance Panel identified as CFP-1 through CFP-9 and I ask that they be marked for identification.

A.L.J. LECAKES: And no further exhibits on the -- on the supplemental testimony. Is that correct?

MR. NICKSON: That is correct. I do note that CFP5, there's a confidential and public redacted version of that exhibit.

A.L.J. LECAKES: We'll mark CFP-1 as Exhibit 84, CFP-2 as Exhibit 85, CFP-3 as 86, CFP-4 as 87, CFP-5 we will mark as 88P for the public version and 88C for the confidential version, CFP-6 as Exhibit 89, CFP-7 as Exhibit 90, CFP-8 as Exhibit 91 and CFP-9 as Exhibit 92 and I just want to confirm that although there was that one exhibit there was no testimony that was offered that was confidential. Correct?

MR. NICKSON: That is correct.

A.L.J. LECAKES: Okay. And the next witness then?

MR. NICKSON: The next witness is

another panel. It's the General Compensation and Benefits Panel consisting of Ms. Lynn Selle, Ms. Valerie Hawthorne, and Mr. Brandon Haspett. The General Compensation and Benefits Panel prepared testimony entitled the Direct Testimony of the General Compensation and Benefits Panel which consists of 28 pages of questions and answers. The General Compensation and Benefits Panel also prepared rebuttal testimony entitled The Rebuttal Testimony of the General Compensation and Benefits Panel which consists of 18 pages of questions and answers and I ask that the direct and rebuttal testimony of The General Compensation and Benefits Panel be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. So that should be in Direct Testimony, it will be The General Compensation and Benefits Panel Direct and in the Rebuttal Testimony, The General Compensation and Benefits Panel Rebuttal. Were there exhibits attached to that -- I'm sorry. The affidavit will be marked as Exhibit 93.

DIRECT TESTIMONY OF THE GENERAL COMPENSATION & BENEFIT'S (GCB) PANEL

1 Q. Please introduce the members of the General Compensation &
2 Benefits Panel.
3 A. The Panel consists of Amy Shiley, Lynn Selle and Valerie
4 Hawthorn.
5 Q. Ms. Shiley, please state your name and business address.
6 A. My name is Amy Shiley. My business address is 6363 Main Street,
7 Williamsville, NY 14221.
8 Q. By whom are you employed and in what capacity?
9 A. I am employed by National Fuel Gas Distribution Corporation
10 ("Distribution" or the "Company"). I was named to my current
11 position, General Manager of Human Resources, effective March 1,
12 2011. In this role, I am responsible for all employment services,
13 including compensation and benefits that are performed for
14 Distribution.
15 Q. Please describe your educational background and experience.
16 A. In May, 1989, I graduated from Syracuse University with a Bachelor
17 of Arts degree in Psychology. In May, 1991, I received a Master of
18 Science degree in Industrial Psychology from Rensselaer
19 Polytechnic Institute. I began my employment with Distribution in
20 November, 1991, as a Management Trainee in the Training and

1 Development area of the Human Resources Department, then
2 progressed to the level of General Manager in the Human
3 Resources Department. Currently I provide employment services
4 for approximately 1,900 employees in New York and Pennsylvania.
5 I also have responsibility for diversity, worker's compensation,
6 compliance, employee relations, employee counseling, payroll,
7 employee benefits and administer the Company employee
8 assistance program.
9 Q. Have you previously testified before the Commission?
10 A. Yes. I submitted testimony in Distribution's 2007 rate proceeding
11 (Case 07-G-0141).
12 Q. Are you familiar with the Affiliate Rules adopted in Case 04-G-
13 1047?
14 A. Yes, I am familiar with the Affiliate Rules.
15 Q. Is your department compliant with these rules insofar as they
16 govern employment and benefit matters with affiliates?
17 Q. Yes.
18 Q. Ms. Selle, please state your name and business address.
19 A. My name is Lynn Selle. My business address is 6363 Main Street,
20 Williamsville, NY 14221.

DIRECT TESTIMONY OF THE GENERAL COMPENSATION & BENEFIT'S (GCB) PANEL

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

2 A. I am employed by Distribution. In 2011, I was named to the position
3 of Assistant General Manager in the Human Resources
4 Department. I am responsible for the management, design,
5 development, implementation, communication, administration and
6 compliance of all benefit programs for National Fuel Gas Company
7 subsidiaries.

8 Q. Please describe your educational background and experience.

9 A. I received a Bachelor of Science Degree in Business Administration
10 with concentrations in accounting and finance from the State
11 University of New York at Buffalo in 1984. I also received a Master of
12 Business Administration Degree from St. Bonaventure with a
13 concentration in finance in 2000. I worked in public accounting for
14 two years and became a licensed CPA. I began my employment
15 with Distribution in October, 1987 and have worked in the area of
16 employee benefits and Trust Plans for more than 17 years. I
17 manage third-party administrators and benefit plan vendors by
18 instructing insurance carriers, trustees, and other administrative
19 agencies outside the Company to effect changes in benefit
20 programs to ensure cost efficient administration of the benefit

1 programs in compliance with ERISA and also with the Affordable
2 Care Act, if applicable. I am also responsible for the day to day
3 administration of the Trust Plans and employee welfare plans.
4 Q. Have you previously testified before the Commission?
5 A. No.
6 Q. Ms. Hawthorn, please state your name and business address.
7 A. My name is Valerie Hawthorn. My business address is 6363 Main
8 Street, Williamsville, NY 14221.
9 Q. By whom are you employed and in what capacity?
10 A. I am employed by Distribution. I was named to my current position,
11 Manager of Employment, in February 2013. In this role, I am
12 responsible for all employment/staffing related matters as well as
13 diversity compliance initiatives and employee relations within the
14 Company.
15 Q. Please describe your educational background and experience.
16 A. I received a Bachelor of Business Administration degree with
17 concentrations in Human Resources and Marketing from the State
18 University of New York at Buffalo in February 2004. I also received
19 a Master of Business Administration degree from the State
20 University of New York at Buffalo in May 2007. I began my

1 employment with Distribution in July 2005 as a Human Resources
2 Specialist and have worked in the Human Resources department
3 throughout my career. All of the roles I've held within Human
4 Resources have been directly related to recruitment, employment,
5 diversity and employee relations.
6 Q. Have you previously testified before the Commission?
7 A. No.
8 Q. What is the purpose of the Panel's testimony?
9 A. The purpose of the Panel's testimony is to discuss
10 Distribution's total compensation package, together with the
11 expected wage increase and employee complement for the Rate
12 Year. In addition, our testimony will provide information about
13 Distribution's employee welfare benefits in regards to the Affordable
14 Care Act and Other Post-Employment Benefits ("OPEBs").
15 Q. What did Distribution use for the wage adjustment for its executive
16 and management employees to be during the Rate Year?
17 A. Distribution has employed a 3% wage adjustment for the Rate
18 Year.
19 Q. Please explain why you believe a 3% increase to be reasonable.

1 A. There are both internal and external factors to be considered when
2 determining an appropriate wage increase for supervisory
3 employees. The primary internal factor is the need to provide a
4 competitive compensation package in the face of increased
5 responsibility and workload being placed on each and every
6 executive and management employee. Distribution confronts the
7 challenges facing many utility companies – namely, a workforce
8 requiring industry-specific, technical skills that are difficult and time-
9 consuming to replace.
10 Q. Please describe the increased workload burden to which you refer.
11 A. There are currently fewer management employees than there were
12 in previous years. To illustrate, in the past 25 years we have
13 reduced our management complement by nearly 30%. Meanwhile,
14 however, the management responsibility of operating a natural gas
15 distribution company over a geographically dispersed area serving
16 731,000 customers in two states in a total of 28 counties has not
17 declined. Indeed, while Distribution's workforce was reducing in
18 numbers, the complexities and responsibilities of operating a
19 regulated gas distribution company were increasing.

1 Distribution has been able to improve the efficiency and
2 effectiveness of providing continuously improved levels of service
3 while reducing the size of its workforce because it has been able to
4 attract and maintain, through its overall compensation and benefits
5 package, a qualified management team. In this context, it is
6 important to recognize that many employees who are technically
7 referred to as management really do not supervise any employees,
8 except in limited circumstances. In fact, many of these employees
9 are providing professional services to the Company such as
10 accounting, legal, engineering, financial and economic services.
11 Further, unlike our unionized workers, these employees do not earn
12 overtime pay for working beyond our normal workday. Following an
13 unprecedented number of retirements clustered around the 2007-
14 2009 timeframe, the employee complement dropped to levels that
15 were not sustainable. Replacement levels for experienced
16 managers fell behind the rate of individuals exiting the Company. It
17 has taken a significant amount of time to replace the experience
18 lost leading up to and immediately following the last rate case as
19 well as keep pace with replacing individuals who are currently

1 exiting employment with the Company. It appears the maximum
2 reduction in management staffing has likely already been realized.
3 Q. How have the complexities and responsibilities of operating a
4 regulated gas distribution company changed?
5 A. There are many examples of how the complexities and
6 responsibilities of operating a regulated distribution company,
7 indeed, any business corporation, have increased. One need only
8 look at the growth in service offerings over the past 20 years to
9 appreciate how the complexities of operating a distribution business
10 have increased. Our service offerings have grown from providing
11 only a handful of bundled sales service rates to residential,
12 commercial, and industrial customers to providing an array of
13 unbundled sales, transportation, and end-use specific rates not only
14 to the traditional burner tip customer, but also to energy service
15 companies ("ESCOs") and municipalities.
16 With the implementation of FERC Order 636 in the early
17 1990's, Distribution became directly responsible for contracting with
18 multiple upstream pipelines for interstate transportation services as
19 well as multiple producers and marketers for natural gas supply
20 services.

1 While Distribution has always maintained a commitment to
2 providing a safe, reliable and secure delivery system, more recent
3 nationwide security concerns have required the Company to
4 accentuate its efforts in this area. Moreover, changes in DOT
5 regulations – such as the operator qualifications requirements –
6 have also increased the complexities and requirements of operating
7 a natural gas distribution system. The DOT's operator qualification
8 rules are requirements established by the DOT's Office of Pipeline
9 Safety to ensure employees working on a pipeline have the
10 knowledge and skills needed to safely and efficiently perform their
11 work. These rules, as adopted by the Commission in its
12 regulations, require Distribution to formally train and qualify
13 employees and contractors to perform specific tasks and to
14 document such efforts.
15 The additional operational, risk assessment and
16 documentation requirements on Distribution due to the Federal
17 Pipeline Safety Improvement Act is another example of the
18 increased complexity in the operation of a natural gas distribution
19 system.

DIRECT TESTIMONY OF THE GENERAL COMPENSATION & BENEFIT'S (GCB) PANEL

1 In addition to increased regulatory requirements in the
2 operations area, increased regulatory oversight in the financial
3 areas has affected the Company. As with all publicly-traded
4 companies, Distribution is directly impacted by the requirements of
5 the Sarbanes-Oxley Act of 2002. The Sarbanes-Oxley Act ("Act")
6 enacted a wide-range of corporate governance and accounting and
7 disclosure rules, including the requirement to maintain disclosure
8 controls and procedures and to enhance internal controls over
9 financial reporting. The requirements of this Act have been far-
10 reaching to all levels and all areas of Distribution and have resulted
11 in a significant increase in work time spent on documenting internal
12 controls associated with almost every work process that affects
13 financial reporting. While Distribution has been able to internally
14 manage this incremental work requirement without increasing the
15 total size of its workforce, staffing for areas most affected by the Act
16 - such as Accounting and Audit - has grown, and the need for
17 additional staff is showing no signs of abatement. In addition, the
18 industry has experienced significant expansion of administrative
19 and supervisory responsibilities in the Human Resources areas, as
20 regulations governing employee benefits, wage and hour

1 requirements and workplace safety, among others, have multiplied
2 and grown more complex. Finding the appropriate talent to remain
3 in these roles or to replace the individuals who hold these
4 responsibilities has required us to step up the pace of our hiring
5 activities in order to maintain the skill set necessary to meet our
6 service obligations.
7 Q. What efforts are you undertaking to maintain a skilled workforce in
8 the face of increasing operational complexity?
9 A. Distribution regularly analyzes the size of its workforce and the
10 effect of each separation from employment to determine whether a
11 replacement or incremental hire is needed. There is no pre-
12 determined procedure for this analysis; rather, each scenario is
13 individually analyzed. The factors considered include the following:
14 • whether the Company possesses the required technical
15 or knowledge skill set;
16 • whether the work can be absorbed by the existing
17 workforce within the department;
18 • whether internal resources can be reallocated without the
19 ultimate need for an outside hire;
20 • whether it is necessary to hire.

1 Q. Have these efforts resulted in additional hires?

2 A. Distribution has significantly increased its recruiting efforts to attract
3 new hires. During the twelve months ended December 31, 2015,
4 105 employees separated from service. During this same time
5 period, 97 employees were hired (and retained). As previously
6 explained, these new hires are not necessarily direct replacements
7 of the individuals who separated from Distribution. Keeping pace
8 with the replacement requirements that arise from having almost
9 nine employees/month (on average) leaving the Company has
10 been a major challenge to the employment team. When a hiring
11 decision is made leading up to a planned retirement, the Company
12 attempts to secure a replacement within a reasonable timeframe
13 that allows for the transfer of knowledge from an experienced
14 management professional. At times, the successful replacement
15 candidate is not identified until after a departure from the
16 organization. This cycle is becoming more common as we continue
17 to experience non-retirement attrition from management employees
18 who are not in the defined benefit pension plan. Having fewer
19 employees incented to stay by a defined benefit pension plan

1 combined with increasing competitiveness in the job market are the
2 major factors driving our recruitment initiatives.
3 Q. Do you expect the number of employees to increase?
4 A. While this can be difficult to predict, the Company doesn't
5 necessarily expect to get bigger or smaller but does anticipate
6 needing to replace most employees who leave the Company. The
7 Company anticipates this replacement effort to take place on a
8 more frequent basis than in the past, given the changing
9 demographics of our management workforce. We continue to
10 focus efforts on retention tools, but recognize today's workforce has
11 evolved to be more mobile than past generations. Since our staff
12 has already been significantly reduced from previous years,
13 replacement needs are expected to continue on a consistent and
14 recurring basis. We expect a steady stream of new hires in the
15 future and we attempt to be proactive in identifying necessary talent
16 for the organization
17 During our annual college recruiting efforts, we regularly
18 recruit engineers and individuals with MBAs in an attempt to assist
19 in succession planning in the Engineering and Operations
20 Departments, as well as the financial areas of Distribution. While

1 such efforts do not consistently result in a specified number of new
2 hires per year, we will continue with this focus.
3 Given the increasing complexities and responsibilities
4 discussed earlier, it is highly unlikely that workforce reductions can
5 continue. While we will not automatically replace employees, given
6 the age of the existing workforce, more frequent non-retirement
7 attrition and the learning curve required to adequately train
8 employees to meet the responsibilities of operating a natural gas
9 distribution system, consistent hiring is likely for the foreseeable
10 future. In addition, we will continue to compete in the labor
11 marketplace to obtain skills necessary for new technologies and
12 increasing regulatory and environmental requirements.
13 Strategic and cost effective benefit plan designs have
14 resulted in defined benefit retirement plan participants now
15 representing a minority of our management workforce. Especially
16 in the absence of a defined benefit pension plan, the
17 competitiveness of our salary structure and resulting benefits
18 package remain critical in retaining employees and in our ability to
19 attract new talent to the Company. Retention is more challenging
20 than ever before and more frequent replacement hiring is expected

1 to occur to fill the roles of individuals transitioning to other
2 employment opportunities in our service territory or elsewhere.
3 Q. Please describe the external factors to which you alluded earlier in
4 your testimony that are considered in determining the supervisory
5 compensation increase for the Rate Year.
6 A. In addition to considering internal workload and responsibility level
7 factors, Distribution must remain competitive in its wages in order to
8 retain the quality employees needed to provide safe, reliable and
9 reasonably priced gas service to its customers. Given the above-
10 discussed gains in productivity achieved by our management
11 employees, an increase above the expected inflation rate is
12 certainly warranted.
13 A 3% increase for supervisory employees is also shown to
14 be reasonable when compared against major national surveys on
15 this subject. The most recent compensation studies that are
16 generally available indicate that budgets for 2016 show average
17 increases of 3.0% to 3.3%. A 3% increase for Distribution's
18 supervisory group is on par with these external sources. We utilize
19 numerous industry and geographically focused compensation
20 surveys to evaluate and determine an appropriate salary budget for

1 Distribution. A thorough analysis of surveys from the following
2 seven sources provides the basis for this recommendation:
3 • American Gas Association Compensation Survey
4 • Culpepper Salary Budget and Compensation Planning
5 Survey
6 • WorldatWork Salary Budget Survey
7 • Hay Group, Salary Planning Survey
8 • Towers Watson Data Services, General Industry Salary
9 Budget Survey Report
10 • Kenexa, Compensation US Salary Budget Survey
11 Q. Please explain how employee salaries are adjusted annually and
12 the rationale behind the combination of a base pay percentage
13 increase and a lump sum percentage award.
14 A. Distribution's total compensation package consists of a portion
15 attributable to base pay increase and a portion attributable to lump
16 sum compensation. The base pay increase becomes a recurring
17 component of compensation while the lump sum compensation
18 gives us the ability to monetarily reward strong performance without
19 having an impact on future salary costs. The total compensation
20 package is designed in this manner in order to control base pay,

1 while at the same time continuing to offer competitive total
2 compensation to Distribution's employees. The 3.0% proposed
3 increase for supervisory employees is to be used for the
4 combination of both base salary and lump sum awards. Utilizing
5 the 3.0% increase in this respect is actually a more conservative
6 compensation strategy than most industry surveys indicate, since
7 these sources generally break out base salary increases from any
8 lump sum/one time merit based payments. Again, Distribution
9 attempts to be competitive and fair, while also remaining cost
10 conscious with respect to salary administration.
11 Annually, Human Resources reviews data sources on this
12 matter and evaluates compensation strategy. A comprehensive
13 summary of this information is disseminated to Company
14 executives for their review. In return, executives prepare proposals
15 regarding base pay and lump sum awards. These proposals are
16 then reviewed by Human Resources and the Company's top
17 executives before being approved and awarded to employees.
18 Q. Is the 3% increase also applicable to the Company's employees
19 covered by collective bargaining agreements?

1 A. No. Distribution has collective bargaining agreements with three
2 union groups, two of which are set to expire in February 2017. The
3 Company will be entering into negotiation discussions in the fall of
4 2016 regarding these agreements. The increase amounts agreed
5 to in the existing contracts and currently being used as
6 placeholders until a final contract is reached are as follows: 1)
7 2.00% for Local 2154, 2154N and 2154S bargaining unit
8 employees; 2) 1.5% for Locals 2199 and 2199 Part-Time
9 employees; 3) 2.0% for Local 2199N employees; 4) 2.0% for
10 Chapter 22 and 22S employees. We expect each of these
11 contracts to be finalized by December 2016 and will update the
12 negotiated increases into our testimony and analysis as they
13 become known.
14 Q. Are there other factors impacting compensation rates for
15 Distribution employees?
16 A. Distribution complies with all applicable wage and hour laws and as
17 such, raised the hourly wage for summer/holiday help employees to
18 the New York state minimum of $9.00/hour on December 31, 2015.
19 Recently approved legislation will require continued increases to
20 the minimum wage that will be phased-in over a multi-year

1 schedule. While the details are still being finalized, paid family
2 leave requirements recently approved in New York state beginning
3 in 2018 will likely require extensive administrative oversight by the
4 Human Resources department. The loss of productivity and
5 resulting financial impact of such leave is currently unknown but will
6 be carefully monitored. We are also closely watching the
7 Department of Labor's proposal to increase the salary level for
8 exempt (from overtime regulations) employees. If the final
9 regulations are promulgated to reflect current proposals, there will
10 likely be significant changes to our management compensation
11 strategy. These changes could take the form of increased salary
12 levels and/or overtime eligibility for certain management
13 employees.
14 Q. Are there additional factors to justify the level of compensation of
15 Company executives?
16 A. Yes. As with management employees, it is important to remain
17 competitive in wages for executives to retain quality and experience
18 among the executive workforce.
19 Q. Has the Company reviewed the pay practices for executives?

1 A. Yes. National Fuel's named executive pay practices are subject to
2 an extensive review and approval process and outlined in National
3 Fuel's proxy statement. For officers not identified in the proxy, the
4 review and approval process is similarly extensive. To assist in the
5 effort, National Fuel Gas Company's Compensation Committee
6 retains the services of Korn Ferry Hay Group, a nationally-
7 recognized firm that performs compensation analyses and review
8 for companies in the energy and other business sectors. Key
9 findings of the most recent national compensation data indicate that
10 total compensation (base salary, annual and long-term incentives)
11 for Company executives is at the median when compared with
12 nationwide utility and general industry executives.
13 Q. Was a compensation study submitted in response to the
14 Commission's directive, in Case 07-G-0141, that the Company
15 demonstrate the reasonableness of the total amount of
16 compensation that its executives and top management personnel
17 receive?
18 A. Yes. In the Company's most recent management audit, the
19 auditors recommended that the Company complete the
20 compensation study within the implementation schedule approved

1 for the audit. The Company complied and submitted a study
2 showing that executive and top management cash compensation
3 was lower than the median, but the overall compensation package
4 (including benefits) was, and remains, reasonable.
5 Q. What OPEBs does Distribution currently provide?
6 A. Distribution currently provides retiree medical coverage for non-
7 union employees hired prior to January 1, 2003 and to union
8 employees hired prior to November 1, 2003. Distribution also
9 provides prescription drug coverage and life insurance benefits to
10 substantially all retirees who are eligible for medical coverage.
11 Q. Has Distribution taken any steps to control the future OPEB costs?
12 A. Yes, Distribution implemented a change to its eligibility criteria for
13 OPEBs, whereby non-union employees hired on or after January 1,
14 2003 and union employees hired on or after November 1, 2003 are
15 no longer eligible for any retiree medical, prescription drug or life
16 insurance benefits. As of July 1, 2015, we have 332 active
17 Distribution employees that have an OPEB benefit with a
18 corresponding accumulated benefit obligation of over $57 million
19 dollars. To place this in perspective, we have 672 full-time
20 distribution employees who do not have this benefit.

1 Also, Distribution aggressively pursues the Medicare Part D
2 reimbursement provided by The Medicare Prescription Drug,
3 Improvement, and Modernization Act of 2003 and have collected
4 over $9 million on behalf of Distribution in drug reimbursement
5 since 2006. We also monitor and reach out to plan participants to
6 enroll into Medicare Part B when eligible, to ensure that Distribution
7 pay only medical expenses that Medicare does not cover. These
8 actions have historically and will continue to save costs.
9 Distribution will continue to incur substantial OPEB costs for its
10 existing retirees and current employees that are provided post
11 employment medical, prescription drug and life insurance coverage,
12 as identified in Mr. Weidner's testimony.
13 Q. What type of cost reduction/control program does Distribution
14 employ for those employees and retirees who are eligible for
15 OPEBs and also for employees who are not eligible for OPEBs?
16 A. Distribution employs an extensive process of annually reviewing
17 each employee benefit plan, primarily in terms of its cost to the
18 Company/employee, value to the employee, and satisfaction with
19 the provider. As a result of this review, benefit plan changes may
20 ensue, or, a benefit plan may be put out for bid to other providers.

1 These actions result in cost savings associated with both active
2 employees (current costs) and retirees (FASB 106 costs) that will
3 vary from year to year based upon the initiatives undertaken.
4 Moreover, the Company continuously keeps abreast of any and all
5 developments in the area of employee benefits through employee
6 benefits publications, benefits committee participation and
7 seminars. For example, after considerable research and care,
8 Distribution maintains that our medical and drug OPEBs are
9 "Retiree Only" plans, therefore not subject to the Affordable Care
10 Act ("ACA") and the increased cost associated with this act.
11 Distribution has continued to remain self-insured for the majority of
12 our medical and drug plans, therefore not subject to the additional
13 fees imposed by insurance carriers to fully insure our plans and to
14 accept the claims risk and additional administrative burden it places
15 upon the insurance carriers. Fully insured plans are subject to the
16 Health Insurer Tax ("HIT") imposed by ACA which the government
17 expects to collect from insured medical plans that will range from
18 $8 billion dollars in 2014 to $14.3 billion in 2018. The HIT imposed
19 by ACA has been suspended by the Consolidated Appropriations
20 Act, 2016 which imposes a 1-year moratorium from January 1,

1 2017 to December 31, 2017. For the most part, however, this was
2 a cost that would not otherwise have been paid by Distribution and
3 its affiliates.
4 Q. Do any of the initiatives affect the prescription drug coverage for
5 your active employees and retirees?
6 A. Yes. In addition to the above-described change, Distribution has
7 worked with its third party administrator, Caremark, to implement
8 drug management programs targeted at the prescription drugs that
9 represent high cost areas under the prescription drug coverage.
10 Under these programs, Caremark works directly with an individual's
11 physician to discuss prescribing protocol in order to ensure that
12 less costly, but equally effective, over-the-counter or prescription
13 drugs have been considered and prescribed, prior to the initial
14 prescription of a more costly drug. For example, once a generic
15 drug was available for Lipitor, Distribution worked with Caremark to
16 place a pre-approval on Crestor to prevent participants previously
17 on Lipitor from automatically moving to another brand drug such as
18 Crestor. We also have a program in place called "Dispensed as
19 Written Penalty" (DAWP) where the plan participant must pay the
20 difference between the brand cost and the generic cost of a drug

1 when the plan participant receives the brand drug instead of the
2 generic drug, when a generic is available.
3 In addition, Distribution and Caremark have aggressively
4 marketed the mail order component of the prescription drug plan to
5 all plan participants who have their drug benefit through Caremark.
6 During 2008, employee drug co-pays increased to a three-
7 tier structure with co-pays of $10/$20/$35 from a $5/$10 co-pay.
8 Then again, in 2013 the co-pays were changed from the
9 $10/$20/$35 to $12.50/$24/$40 co-pay for active employees and
10 retirees who retired during 2008 and who have OPEBs. In 2011,
11 retiree drug co-pays were increased for retirees that retired prior to
12 June, 2008 and who had a $0 and $5 co-pay to incent the retirees
13 to use mail order to refill maintenance prescription drugs which
14 results in costs savings for Distribution. During 2008, the monthly
15 medical and drug contribution percentage for retirees increased to
16 be similar to the active employee medical and drug contribution
17 percentage and has continued to increase to date for retirees and
18 active employees.
19 It is important to recognize that this is a cost mitigation effort.
20 Were it not for these efforts, prescription drug costs would be even

1 greater. Drug manufacturers are aggressively marketing high cost
2 specialty drugs that give new hope to patients with cancer, hepatitis
3 C, multiple sclerosis, Parkinson's disease and rheumatoid arthritis,
4 just to name a few. As it is abundantly clear from the debate
5 currently raging in this country, prescription drug costs continue to
6 increase dramatically. Distribution's efforts, while effective, serve
7 only to dampen the effect of these broad based and nationwide
8 increases in prescription drug costs.
9 Q. Did Distribution adopt any new trust plan benefits?
10 A. Yes. In 2003, Distribution froze the Retirement Plan to new
11 participants. At the time Distribution froze the Retirement Plan, it
12 was determined that a new retirement-related benefit needed to be
13 developed in order for Distribution to continue to offer a competitive
14 benefits package. Thus, Distribution designed a new benefit
15 whereby Distribution contributes to a Retirement Savings Account
16 for new hires. As of July 1, 2015, there are currently 340 active
17 Distribution employees who have the Retirement Plan benefit and
18 665 employees who have the Retirement Savings Plan.
19 This new benefit should, in the future as the Company hires
20 new employees, eliminate the effect of fluctuating equity and credit

1 markets on Distribution's annual pension expense, while enabling
2 Distribution to remain competitive in its benefits package for new
3 employees. In other words, pension expenses will not be
4 eliminated; the annual volatility, however, of the level of expense
5 should be significantly reduced as the proportion of Distribution's
6 overall employee base under the new plan increases. This
7 transition will take time and for the foreseeable future Distribution's
8 pension costs will be overwhelmingly determined by the costs of
9 managing the Retirement Plan.
10 Q. What other major benefits are offered to non-union employees
11 generally hired during 2003 (new hires) and after that differ from
12 what is offered to employees that are Retirement Plan participants?
13 A. For the drug plan, the new hires have coinsurance of
14 20%/20%/50% (generic/preferred brand/non-preferred brand)
15 instead of fixed drug co-pays. Up until January 1,2015, their dental
16 plan benefits were very limited, so based on employee feedback
17 and efforts to make their benefit package more comparable to what
18 other employees are receiving in the market, the dental plan
19 benefits were enhanced effective January 1, 2015. In order to
20 provide a more competitive benefit without increasing cost to

1 National Fuel Gas Company subsidiaries, we added a Preferred
2 Provider Network to the dental plan for all plan participants and
3 concurrently enhanced plan benefits for new hires. With this
4 change, we were able to decrease the overall dental cost to
5 Distribution and to employees who go to a participating dentist.
6 Q. You mentioned that the Company uses compensation as a tool to
7 retain some employees. Please explain.
8 A. Yes. Like Distribution, fewer employers now offer a defined benefit
9 plan, and therefore they are increasingly relying on other incentives
10 to retain key employees. One of those incentives used by
11 Distribution is stock equity awards for non-officers. These awards
12 are not tied to financial performance, but rather they vest after
13 periods of time. If the employee were to leave the Company before
14 the grant vested, it would be forfeited, and no award would be paid.
15 Q. Is Distribution in compliance with Section 3.0 of the Affiliate Rules
16 adopted in Case 04-G-1047 regarding personnel?
17 A. Yes.
18 Q. Does this conclude your testimony?
19 A. Yes.

CASE 16-G-0257 REBUTTAL TESTIMONY OF THE GENERAL COMPENSATION & BENEFIT'S PANEL

Q. Please state the members of this General Compensation & Benefit's Panel ("Panel").

A. We are Lynn Selle, Valerie Hawthorn, and Brandon Haspett.

Q. Are there any changes to the individuals making up this Panel?

A. Yes. Mr. Brandon Haspett has replaced Amy Shiley as a member of this Panel.

Q. Mr. Haspett, please state your name and business address.

A. My name is Brandon Haspett. My business address is 6363 Main Street, Williamsville, NY 14221.

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

A. I am employed by National Fuel Gas Distribution Corporation ("Distribution" or the "Company"). In November 2015, I was named to my current position of Benefits Analyst in the Human Resources Department. I am responsible for the management, administration, communication, and compliance of several benefit programs for National Fuel Gas Company subsidiaries.

Q. Please describe your educational background and experience.

A. I received a Bachelor of Science Degree in Accounting from the State University of New York at Buffalo in February 2011. I am currently

pursuing a Master of Business Administration Degree part-time from the State University of New York at Buffalo with expected graduation date of May 2018. I started my career in public accounting at Ernst & Young, LLP for two and a half years prior to joining Distribution in June 2013. I began my employment at Distribution in the Audit Services department where I worked extensively auditing the Company's benefit and trust plans, prior to joining the Human Resources department.

Q. Have you previously testified before the Commission?

A. No.

Q. Did this Panel previously submit testimony in this proceeding?

A. Yes, we previously submitted Direct Testimony with respect to, among other things, Distribution's total compensation package, expected wage increase, and employee complement for the Rate Year.

Q. Mr. Haspett, do you adopt the prefiled Direct Testimony of this General Compensation & Benefit's Panel?

A. Yes.

Q. What is the overall purpose of this Panel's Rebuttal Testimony?

A. We address Staff Witness Gadomoski's recommendation to deny the Company's request for recovery of the Company's executive incentive pay in rates.

Q. Mr. Gadomski testifies that "the Company's request for recovery of executive incentive pay in rates should be rejected" because he claims that "the Company has not provided the information necessary to make an adequate assessment and determination of the reasonableness of the Company's executive compensation request." Do you agree?

A. No.

Q. Please explain.

A. To begin with, the Company submitted compensation benchmarking information responsive to Mr. Gadomski's requests (See UFR-27 and the Company's response to DPS-48) attached hereto as Confidential Exhibit (GCB-1) and in compliance with the Commission's 2007 directive that the Company submit with its "next major rate filing" an "executive compensation study to demonstrate the reasonableness of the total amount of compensation that its executives and top management personnel receive." The study,

prepared by the Hay Group, an established compensation consulting firm, was completed in 2014, prior to the current rate case, because in a subsequent management audit, the Commission adopted a recommendation requiring the Company to complete the compensation study as part of its implementation plan. The Company fully complied with the audit requirement and the Hay Group compensation study was accepted by the auditors as being in full compliance with the Commission's 2007 order.

Q. Please continue.

A. Given that we provided the study required by the Commission, and that study met the requirements of the Commission's order as determined by the third-party auditor picked by the Commission, then Mr. Gadomski appears mistaken when he claims that "the Company has not provided the information necessary to make an adequate assessment and determination of the reasonableness of executive incentive pay in rates." In fact, the Company did provide the necessary benchmarking information with which to make a determination as to the reasonableness of executive compensation (including incentive pay) and Mr. Gadomski's disagreement

appears based on his misunderstanding how executive compensation systems work.

Q. What did the Hay Group survey that was accepted by the auditors conclude about Distribution's compensation levels?

A. The Hay Group found that, overall, salary (including target incentive pay levels) and benefits for the survey positions were at the median of the general industry comparator groups. This was no surprise to Distribution because the Company has long aimed at the median or slightly below for overall target incentive levels. But the results of the study were not to Distribution's satisfaction, from the position of job market competitiveness.

Q. Please explain.

A. The study showed that the overall median level was achieved because the survey salary levels were well below the median, while benefits were above the median. As Staff knows (and as explained in our initial testimony), starting in 2003, National Fuel froze the retirement plan to existing employees and it is unavailable to new participants. Although the Company's Retirement Savings Account, which is available to newer employees, is competitive, in

combination with below-median salary levels, the overall compensation package may lag the market median.

Q. Mr. Gadomski claims, however, that the Company's compensation and benefits are above what he defines as "market competitive." Do you agree?

A. No. Mr. Gadomski confuses a target incentive level with "market" pay.

Q. Please explain.

A. Mr. Gadomski is correct that incentive compensation systems, such as National Fuel's, are designed with a "target incentive level," or an award amount that is established on the assumption that the executive's goals are achieved at the 100% level. This is the incentive compensation level that was benchmarked in the Hay Group's January 2014 study (and Hay Group's National Fuel studies generally). Hay Group found, and Mr. Gadomski acknowledged, that National Fuel's total compensation levels (salary, short- and long-term incentives, benefits) were at the median of the comparator group. From this Mr. Gadomski concluded, not incorrectly, that the target incentive levels for

National Fuel executives was also at the median. But Mr. Gadomski then misidentified the target incentive level as being within "market," with a subsequent payout above the target incentive level as being beyond "market" and therefore unreasonable.

Q. Why was Mr. Gadomski's analysis erroneous?

A. It is erroneous to call target incentive levels "market" in order to declare a payout that exceeds the target incentive to be in excess of "market" and therefore unreasonable. The very idea of a target incentive level is to establish a target level for the executive to *exceed* so that the executives' performance metrics are also exceeded. When that happens, the Company performs better compared to its peers, and all stakeholders benefit. This is typical of similar annual incentive plans provided by other companies, including National Fuel's peers.

Q. But Mr. Gadomski states that a benchmarking comparison of total actual compensation would "likely show that NFG executive compensation is beyond [market] for many positions." Is this correct?

A. The Hay Group reports provided for National Fuel do not typically include benchmarking of actual compensation, except that senior executives' actual compensation is compared to the Company's peer group.

Q. What does that information show?

A. For senior executives, Hay Group's 2015 annual review of executive compensation uses proxy data for similar positions at fifteen peer group companies identified in the Company's proxy. Those peer group companies, selected by the Hay Group, were the following:

AGL Resources, Inc.
Atmos Energy Corp.
Cabot Oil and Gas Corp.
Energen Corp.
EQT Corp.
MDU Resources Group, Inc.
New Jersey Natural Resources Corp.
Questar Corp.
Range Resources Corp.

SM Energy Corp.

UGI Corp.

Ultra Petroleum Corp.

WGL Holdings, Inc.

Whiting Petroleum Corp.

Q. Is the peer group identified in the proxy the same as the comparator group used by Hay Group in the 2014 report?

A. No. Although the proxy peer group companies are included in Hay Group's energy industry database, the proxy list is a subset of the larger comparator group. Proxy peer groups are used to benchmark corporate performance using publicly available information.

Q. What did the Hay Group study find using proxy peer group information?

A. Results varied for different forms of compensation, but for total direct compensation, the senior executives were paid below the median of the peer group. This information is shown in Confidential Exhibit (GCB-2), Sheet 1.

Q. Does that, in your opinion, mean that the senior executives were paid below "market?"

A. No. Again, it means that the compensation systems at peer companies produced higher results for the benchmarked executives during the survey period. Those companies may have performed differently, had different kinds of goals, or different weighting of similar goals. Nonetheless, the Company is cognizant of compensation disparities and considers those comparisons as part of its overall compensation design and planning process.

Q. Mr. Gadomski is also challenging the Hay Group's comparator group companies used in the 2014 compensation survey. Do you agree?

A. No. Mr. Gadomski appears to claim that the job positions benchmarked in the Hay Group survey may not match the job descriptions of companies used in the comparator peer group. He is contending, essentially, that the Hay Group failed to do its job of benchmarking Distribution employee and officer compensation levels. With regard to matching, the Hay Group report said this (at page 10):

> NFG executive and top management jobs were evaluated using Hay Group's job evaluation methodology. Jobs were sized using our proprietary models, reflecting how NFG's executive and top management role structures compare to similar jobs at other organizations. Job sizing allows a comparison to jobs in the external marketplace with equivalent experience, management scope and accountabilities.

Q. Please continue.

A. We rely on Hay Group and other consulting firms, together with Distribution managers and subject matter experts, to develop reliable job matches. While Distribution has expertise in describing Distribution's job positions, we do not have the knowledge to understand how to match those positions to the content of job positions at comparator companies. For that we rely on the Hay Group's expertise. According to the World at Work Handbook of Compensation, Benefits and Total Rewards: A Comprehensive Guide for HR Professionals (2007), the use of compensation experts is a recommended practice:

> Those familiar with or knowledgeable about the work should do the matching. Ideally, managers or subject matter experts should match jobs. If this isn't possible, compensation practitioners do the matching based on their knowledge of the jobs, which they

> have gained by interviewing incumbents and managers, or reading internal job descriptions (p. 169)

Q. Did Mr. Gadomski request Hay Group's job matching methodology?

A. No. Mr. Gadomski asked for a "percentage of peer group employees utilized from general industry versus utility industry companies, for each position matched." His contention, by his own example, is that some National Fuel positions may have no general industry peers, in which case benchmarking to general industry peer companies would be unreliable.

Q. Do you agree with Mr. Gadomski's approach?

A. No. Mr. Gadomski assumes that the positions matched to the general industry peer group pay more than the same positions matched solely to a utility peer group. This approach is pointless because, as the Company showed in its response to DPS-48 (attached hereto as Confidential Exhibit (GCB-3)), it recruits in all positions from general industry employers, and also loses employees to competing, general industry employers inside and outside of the Company's service territories. So, a vacated accountant position is filled with candidates from employers other

than utilities, and the position used as an example by Mr. Gadomski - a "utility engineering executive position" - would also be filled by candidates from either utility industry or general industry peer groups. There may be some positions that are so unique to the utility industry that they can be filled only by recruiting with the utility industry, but they are so few and so infrequently vacated as to be statistically insignificant.

Q. You testified that stakeholders benefit when performance targets are achieved or exceeded. Please explain.

A. By "stakeholders" I mean customers, shareholders, employees, the community and the environment. National Fuel's executive compensation programs include goals to improve customer service, safety, reliability and environmental compliance, in addition to financial performance.

Q. Do you agree with Mr. Gadomski's contention that the performance goals for incentive pay are not "in line with Commission objectives related to customer service, the environment, safety and reliability"?

A. No. Mr. Gadomski overlooks the majority of performance goals the Company's executives are expected to achieve in order to earn incentive pay.

Q. Please explain.

A. As shown in the Company's responses to DPS-180 and DPS-48 (attached hereto as Confidential Exhibit (GCB-4)), the majority of performance targets related to Distribution's executive incentive plan are focused on customer service, safety, reliability and environmental protection. More particularly, in 2015 there were a total of 135 performance goals distributed among the 22 officers who allocate time (in varying amounts) to Distribution. Of those 135 goals, 77 benefit Distribution's customers in one form or another.

Q. Please provide examples of what you mean by performance goals focused on customer service, safety, reliability and environmental protection.

A. For the senior executives whose goals are published in the proxy, the list includes the following goals (See the Company's response to DPS-48 Attachment #2):

- Safety - measured by number of OSHA recordable injuries in the utility and pipeline divisions;
- Mainline installation targets;
- Service installation targets;
- HEAP basic grants collected;
- Operational safety performance measured by New York operational safety standards compliance and New York outstanding leak reduction;
- Barcelona cost measured by actual expense versus target;
- Projects measured by number of projects (e.g. pipeline construction) that met in-service dates or unit commissioning dates.

Also included in response to DPS-180, but overlooked by Mr. Gadomski, were additional performance goals expected of executive officers, including the following:

- Residential gas system expansion projects;
- Pipeline safety performance measures, including
    - Leak/odor calls metrics;
    - Mismarks;
    - Outstanding leaks.
- State government ethics compliance training;
- Minority recruiting and hiring targets;
- Gas safety compliance program;
- Implementation of state management audits;
- Tax challenges affecting rates;
- Insurance coverage renewals;
- Construction quality management improvements;
- System modernization for transmission facilities;
- monitoring and compliance with environmental regulations affecting pipeline construction and operations.

In addition, Staff overlooks that any performance goals related to the financial performance of the Company are not necessarily

contrary to the interests of its customers. Goals related to financial performance can – and in the Company's case do – align with customer interests. The Company runs an efficient, well-managed and highly productive business, providing safe and reliable service, exemplary customer service, with robust low-income programs and no rate increases for nearly a decade. These sound practices benefit all our customers – and not surprisingly – result in solid financial performance for the Company. In addition, our customers benefit via the earnings sharing mechanism currently in place under the Joint Proposal agreed to in Case 13-G-0136. So if, due to prudent management and efficiency, the Company's financial performance improves, our customers share in those earnings. For Staff to insinuate that goals linked to financial performance are contrary to the interests of customers is simply an incorrect assertion as it grossly misportrays the Company's long-time approach to ensuring the safe, reliable and affordable service to its customers.

Q. Is there any other reason why you believe that Distribution's executive performance incentives are reasonable?

A. National Fuel's shareholders have voted in support of the compensation of the Company's top executive officers. Known colloquially as "say-on-pay," in accordance with provisions of the Securities Exchange Act of 1934, shareholders are asked to approve the following resolutions:

> RESOLVED, that the compensation paid to the Company's named executive officers, as disclosed herein pursuant to Item 402 of Regulation S-K and described in the Compensation Discussion and Analysis, accompanying compensation tables and related narrative discussion, is hereby approved.

As explained in the proxy statement, "this proposal allows stockholders to take part in a non-binding, advisory vote to approve the compensation of the Company's named executive officers." In 2015, the say-on-pay vote yielded a result of 96% of votes cast in favor of the executives' compensation. In 2016, the result was nearly identical.

Q. Does this conclude your rebuttal testimony?

A. At this time, yes.

A.L.J. LECAKES: Were there exhibits attached to any of those testimonies?

MR. NICKSON: Yes, Your Honor. There were four exhibits attached to the rebuttal testimony of The General Compensation and Benefits Panel identified as GCB1 through GCB4 and I note that there are public and confidential versions of GCB1, GCB2, GCB3, and GCB4.

A.L.J. LECAKES: But no confidential testimony. Is that correct?

MR. NICKSON: That is correct.

A.L.J. LECAKES: That was attached to the rebuttal testimony?

MR. NICKSON: Yes, Your Honor.

A.L.J. LECAKES: Okay. So starting with: GCB1, the public version will be 94P, the confidential version will be 94C; GCB2, the public version will be 95P, the confidential version 95C; GCB3, 96P for the public version, 96C for the confidential version; GCB4, 97P for the public version, 97C for the confidential version. Those all the exhibits?

MR. NICKSON: Yes, Your Honor.

A.L.J. LECAKES: Okay. Next witness?

MR. NICKSON: The next witness is the company's Tariff Reorganization Panel. The Tariff

Reorganization Panel consists of Michael E. Novak and Sheila Suarez. They've prepared testimony entitled The Direct Testimony of The Tariff Reorganization Panel which consists of 14 pages of questions and answers. The Tariff Reorganization Panel also prepared rebuttal testimony entitled The Rebuttal Testimony of The Tariff Reorganization Panel which consists of seven pages of questions and answers. I ask that the direct testimony and rebuttal testimony of The Tariff Reorganization Panel be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. So the first file issue to appear as Tariff Reorganization Panel Direct Testimony in the company Direct Testimony folder and then next would be The Tariff Reorganization Panel Rebuttal Testimony in the company Rebuttal Testimony file. The affidavit will be marked as Exhibit 98.

DIRECT TESTIMONY OF TARIFF REORGANIZATION PANEL

Q. Will the members of the Tariff Reorganization Panel ("Panel") please identify yourselves.

A. We are Michael E. Novak and Sheila Suarez.

Q. Mr. Novak, please state your name and business address.

A. My name is Michael E. Novak. My business address is 6363 Main Street, Williamsville, New York 14221.

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

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

Q. Please state briefly your educational background.

A. I graduated from the State University of New York at Buffalo with a Bachelor of Science degree in Civil Engineering in 1981 and a Master's degree in Business Administration in 1982.

Q. Please state briefly your professional experience at National Fuel Gas.

A. In April 1984, I began my career at National Fuel Gas Supply Corporation ("Supply") in its Valuation Department. Later that year I transferred to

Supply's Gas Control Department which transitioned into its Gas Supply Department. In 1992, as a consequence of Federal Energy Regulatory Commission's ("FERC") Order 636 I transferred from Supply to Distribution with the rest of the Gas Supply Department. In 1999, I transferred to Distribution's Transportation Services Department and in 2001, to Rates and Regulatory Affairs.

Q. Do you have any professional experience that is particularly relevant to the testimony provided herein?

A. Yes. With the American Gas Association's ("AGA") Federal Regulatory Committee I have participated in several efforts regarding the interaction of the gas and electric industries, notably AGA's Gas Electric Interdependencies Steering Group. I also served on AGA's Market Transparency Task Force and Natural Gas Price Indices Task Force. Finally, I am one of Distribution's representatives to the New York Independent System Operator ("NYISO"), participating in its Electric Gas Coordination Working Group and other NYISO committees as gas issues arise; notably

its Business Issues Committee - Market Issues Working Group ("MIWG").

Q. Have you previously testified before the New York State Public Service Commission?

A. No.

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

A. Yes. I have presented testimony before the Pennsylvania Public Utility Commission and FERC.

Q. Ms. Suarez, please state your name and business address.

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

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

A. I am employed by Distribution as a Senior Manager in the Rates and Regulatory Affairs Department.

Q. Please state briefly your educational and professional experience.

A. I graduated from Canisius College in 1986 with a Bachelor of Science Degree in Accounting. In 1993 I completed a Master of Business Administration Degree at the State University of New York at Buffalo. In

June 1986 Distribution employed me as a Junior Rate Analyst in the Valuation Department, which has since been reorganized into the Rates and Regulatory Affairs Department. Over the years I have been promoted to various Rate Analyst positions progressively gaining responsibility within the Rates and Regulatory Affairs Department. In March 2016 I was promoted to Senior Manager my present position.

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

A. Yes. I have presented testimony before the New York Public Service Commission and the Pennsylvania Public Utility Commission.

Q. What is the purpose of the Panel's direct testimony?

A. The primary purpose of the Panel's direct testimony is to propose replacing existing tariff, PSC No. 8 with a new tariff, PSC No. 9.

Q. How will PSC No. 9 differ from PSC No. 8?

A. PSC No. 9 is a complete overhaul of PSC No. 8, which has been added to and modified over the years. The tariff is being reorganized into sections as

permitted by the Commission's Regulations and accommodated by the Commission's Electronic Tariff System. The General Information Section will be the first section followed by individual sections for each service classification.

Q. Will this reorganization affect the way each tariff leaf is numbered?

A. The Leaf numbers in PSC No. 8 will be replaced with a combination of a Section Numbers and Leaf Numbers in PSC No. 9. Rather than a single sequence of numbers throughout the entire tariff, Leaf Numbers will restart at number 1 in each Section.

Q. What are some of the other changes proposed in PSC No. 9?

A. Other changes affect both the appearance and organization of the tariff. An Arial 10 point font type and size will be used consistently throughout PSC No. 9. Blank pages are being removed. The terms used throughout the tariff are being updated to provide consistency, reflect current business practices, address updated technology, make conforming modifications to definitions (including

references to the Commission's Uniform Business Practices) and incorporate greater use of gender neutral terms to describe customers.

Q. Please describe the PSC No. 9's organizational changes.

A. The organization and/or numbering of some tariff sections and sub-sections is being modified to match the numbering pattern used most prevalently in the tariff to provide further consistency. As a result, references to these sections and sub-sections are being changed to conform to the new organization and/or numbering. Finally a new General Information Section is being added to house the rates for service classifications and miscellaneous tariff-based fees. Additionally, this new section will identify the service classifications subject to various refund/surcharge provisions.

Q. How does the Company classify the changes described above?

A. While these changes are important, they are more broadly described as non-substantive or housekeeping in nature.

Q. Will PSC No. 9 contain any substantive changes?

A. Yes. These changes fall into four broad categories. The first category of substantive changes reflects the elimination of service classifications and general information sections that are no longer used and useful. The second category of substantive changes reflects the modifications, including additions and deletions of tariff language, to the remaining service classifications and general information sections. The third category of substantive changes reflects the addition of new general information sections. The fourth substantive change is to update rates to recover the proposed increase in this case, along with a tracker and incentive mechanism for system modernization.

Q. Will the Company be adding any new service classifications?

A. No.

Q. In which testimony does the Company describe these changes?

A. Except for those items discussed in the testimony herein, substantive changes to the tariff will be

discussed in the testimony of other witnesses.

Q. Why is the Company proposing to eliminate certain service classifications in PSC No. 9?

A. The new tariff eliminates service classifications that have not had customers for many years, if ever. Similarly, the new tariff eliminates general information sections that are no longer relevant.

Q. How does this affect the organization of the tariff?

A. Some of the remaining service classifications are being relocated to fill in gaps within the sequence of service classifications. Similarly, remaining service classifications are being relocated, and new general information sections are being instated, to fill in gaps within the sequence of general information sections.

Q. Will these changes affect the Monthly Gas Cost related statements filed by the Company?

A. Yes, the Company is proposing to eliminate the Customer Balancing & Aggregation ("CBA"), the LICAAP Minimum Charge ("LICAAPMC"), the LIRA Minimum Charge ("LMC"), the Minimum Bill Credits ("MBC"), the State Income Tax Credits ("SIT") and the ULIEEP Surcharge

("US") Statements. Low income tracker and regulatory assessment/audit tracker statements will be added when actual changes tracking these costs are incurred.

Q. Is the Company providing any exhibits summarizing the tariff changes?

A. Yes. Please refer to Exhibit___(TRP-1) for a summary of the service classification changes and Exhibit___(TRP-2) summary of the general information changes. Exhibit___(TRP-3) provides a cross reference key showing the approximate locations of general information sections and service classifications in PSC No. 9 relative to their current location in PSC No. 8. Finally, Exhibit___(TRP-4) provides a brief description and categorization of the changes to each leaf, as applicable, with respect to PSC No. 8.

Q. Why are these locations approximate?

A. Due to the changes described herein, PSC No. 9 is approximately 140 pages shorter than if the same changes would have been made to PSC No. 8.

Q. Does the elimination of service classifications

affect the rates?

A. No. As can be explained by the Cost of Service and Rate Design panel, even though references to these service classifications may, in a few cases, be included in the rate calculations, the service classifications proposed for elimination have no customers or throughput.

Q. Is the Tariff Reorganization Panel sponsoring any of the substantive changes proposed in PSC No. 9?

A. Yes. The Company is proposing the right to restrict consumption of gas by electric generation facilities in excess of the amount delivered to the Company and is proposing revisions to the applicable penalty rates during Operational Flow Order ("OFO") periods.

Q. Please explain the proposed restriction applicable to electric generation facilities.

A. In some other utility service territories within New York, there have been instances where electric generation facilities have continued to consume gas in excess of what they were providing to the utility for transportation purposes (or available from the utility for sale) potentially threatening the

reliability of the utility system. Even though penalty rates were imposed, the electric generation facilities continued to consume gas because the NYISO market structure permitted cost recovery of penalties.

Q. Has NYISO taken any steps to remedy this situation?

A. Yes. NYISO's MIWG conducted meetings to investigate potential remedies and developed tariff language that would exclude recovery of costs and penalties associated with unauthorized natural gas consumption from NYISO's generator reference levels when pipelines and local distribution companies, such as Distribution, restrict access to imbalance gas. NYISO filed tariff changes which were initially approved by FERC in Docket No. ER16-168 on February 18, 2016.

Q. Please explain the purpose of the proposed language.

A. The proposed language, in General Information Section 20.D.(2) is designed to work in concert with NYISO's FERC Tariff and to clearly identify the restriction applicable to electric generation facilities, relative to other more generally

applicable restrictions.

Q. Please explain the changes to the OFO penalty rates.

A. The existing OFO pricing structure was developed in an era where the daily index pricing of gas at liquid market trading points was less prevalent and included a reference to the highest per Mcf cost of gas purchased in the Company's gas supply portfolio during the days when the OFO was applicable. If the Company is not purchasing relatively expensive gas during this period, the OFO rate may not be sufficient to properly encourage ESCOs to deliver gas to the system to avoid imbalances.

Q. Please describe the proposed change.

A. The calculation of the OFO rate in General Information Section 20.E.(1).b is being simplified; the new daily penalty of $25 is added to the Daily Index price described in PSC No. 9 General Information Section 29 (PSC No. 8 General Information Section 51). The Company's gas purchases are no longer a component of the OFO penalty rate calculation. Additionally, one penalty tier would become effective at 2%, aligning that

tier with an analogous tier applicable to SC 13 customers in General Information Section 20.E.(2).a. Finally, if the Company has simultaneously issued a Notice of Unauthorized Period, as set forth in SC 11, during which the applicable SC 11 deficiency imbalance rate exceeds the applicable OFO rate, the SC 11 rate shall apply herein.

Q. What is the purpose of the SC 11-related change?

A. The Company wants to eliminate the possibility that by issuing an OFO it would actually lower the penalty rate applicable to underdeliveries.

Q. Are there any other changes to rates designed to prevent imbalances?

A. Yes. In SC 11, for months during which an Unauthorized Period is declared, when the Average Monthly Index, as set forth in PSC No. 9 General Information Section 29, exceeds the Total Gas Cost Rate for the month, the month end deficiency imbalance sales rate shall be calculated using the Average Monthly Index in place of the Total Gas Cost Rate. The logic is similar to that used for in General Information Section 20.E.(1).b.; if market

pricing outruns the deficiency sales rate, it ceases to be an effective protection against creation of imbalances. The new language remedies that potential.

Q. Does this conclude your panel testimony?

A. Yes, at this time.

Q. Please state the members of this Tariff Reorganization Panel ("Panel").

A. We are Michael E. Novak and Sheila Suarez.

Q. Please state your business address.

A. Our business address is 6363 Main Street, Williamsville, New York, 14221.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, we previously submitted testimony as members of the Tariff Reorganization Panel on behalf of National Fuel Gas Distribution Corporation ("Distribution" or "the Company").

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of the Panel's rebuttal testimony is to respond to the testimonies of Staff Gas Policy and Supply Panel ("Staff").

Q. What portion of Staff's testimony does the Panel wish to respond to?

A. This Panel will address Staff's Electric Generation testimony first and the Transportation and Balancing Procedures and Charges testimony second. While the Company either agrees with or does not oppose most of Staff's proposals in concept, the Company proposes a more effective means to implement a number of these proposals.

Q. With respect to Electric Generation, what does Staff propose and does the Panel agree with such proposal?

A. Staff proposes that the Company revise tariff leaf 291, which currently provides that a daily deficiency imbalance from 10% to 15% of usage is cashed-out at 110% of the Index Price of gas to state that any daily deficiency imbalance from 2% to 15% be cashed out at 110% of the Index Price of gas. The Panel agrees with Staff's position and points out that it did, in fact, already propose this tariff revision as a part of the tariff reorganization ("P.S.C. No. 9") as an "errata" because the intent of the prior revisions to leaf 291 was to have the Daily Deficiency Imbalance tiers consistent and symmetrical with the Daily Surplus Imbalance tiers, as Staff proposes in its testimony.

Q. Where can this tariff revision be found in P.S.C. No. 9?

A. In Distribution's currently effective tariff ("P.S.C. No. 8"), leaf 291 is part of Service Classification SC-21 - Basic Gas-For-Electric-Generation Service Tariff ("SC-21"). By referencing Exhibit ___ (TRP-1) filed with the Panel's Direct Testimony ("Initial Testimony"), it can be observed that SC-21 was relocated to SC-17 in "P.S.C. No. 9". Further, in the Description of Changes Column for P.S.C. No. 8 – leaf 291 of Initial Testimony Exhibit ___ (TRP-4), an "errata" change is referenced. Finally, in the PSC No. 9 Section-Leaf #'s column of Initial Testimony Exhibit ___ (TRP-3), P.S.C. No. 8. Leaves 287 to 293 for Service Classification No.21 are shown as reorganized within

P.S.C. No. 9 as Section-Leaf #'s 17-1 to 17-7. Specifically, P.S.C. No. 9 Section-Leaf 17-5 shows the Daily Deficiency Imbalance tiers consistent and symmetrical with the Daily Surplus Imbalance tiers (on P.S.C. No. 9 – Section-Leaf 17-4), as Staff proposes in its testimony.

Q. Does the Company agree with Staff's testimony that imbalance tiers listed on tariff leaves 290 and 291 should be properly labeled as penalty tiers since these tiers and the daily balancing tier levels applied to power generators or any daily balanced customers should be clearly identified as to what is a penalty and what is a gas cost?

A. While the Company agrees with the intent of Staff's proposal, it believes that it would be more efficient to add language expressing this intent in P.S.C. No. 9 - General Information Section 29 – Cash Out Index for Imbalance Resolution which corresponds to currently effective P.S.C. No. 8 - General Information Section 51. Distribution would take an analogous generalized approach in developing the corresponding changes to its GTOP.

Q. Why does the Company believe this is a more efficient approach?

A. Under Distribution's currently effective tariff, electric generators are not restricted to service solely under SC-21. For example, electric generators may also receive service under P.S.C. No. 8 – Service Classification Nos. 13D (SC-13D or P.S.C. No. 9 SC-13) and 13M

(SC-13M or P.S.C. No. 9 SC-18). Like SC-21, these service classifications reference currently effective General Information Section 51. If the proposed change was limited to SC-21, it could create an unintended incentive for electric generators to receive service under other service classifications.

Q. Does the Company's agree with Staff's recommendation that the additional charge in SC-21 tariff leaf 293 (Special Provisions Item 7) be raised to $25 per Mcf during non- Operational Flow Order (OFO) periods and $50 per Mcf during an OFO period?

A. Yes, but the Company believes corresponding special provisions applicable to electric generators should be added to SC-13D and SC-13M to avoid creating an unintended incentive for electric generators to receive service under these other service classifications.

Q. What is the Company's position with Staff's testimony that current tariffs also should require that new generators, and existing ones that fail to comply with an interruption, install and pay for remotely operated valves?

A. The Company agrees in principle but proposes that its tariff language would 1) allow for the installation of other equipment that is functionally equivalent to a remotely operated valve and 2) clarify that

installation and payment would include the cost of installing telemetric equipment for monitoring purposes.

Q. Moving on to Staff's testimony regarding Transportation and Balancing, does the Company agree with the recommendation that to provide a sufficient incentive for the protection of system integrity, Distribution's Service Classification No. 11 – Deficiency Imbalance Gas Sales Service for Transportation Customers (SC-11) be revised to provide that the penalty for under delivery during non-OFO events be increased from $10 to $25 per mcf and for OFO events be increased from $25 to $50 per mcf?

A. The Company does not object to Staff's proposal but believes that additional language is needed in SC-11 to clarify that for rate calculation purposes, Unauthorized Periods would be functionally equivalent to an OFO event. Further, the Company does not intend to remove currently effective language that permits use of the Daily Index Rate under P.S.C. No. 8 - General Information Section 51 (P.S.C. No. 9 - General Information Section 29) when such rate exceeds the otherwise applicable rate. In addition, in this instance the Company agrees to add language to SC-11 providing that portion of the rate charged that exceeds the Total Gas Cost Rate be identified as penalty charges, as recommended by Staff.

Q. Does the Company accept Staff's recommendation that daily balancing tier levels applied to daily balanced customers should also be clearly identified as to what is a penalty and what is a gas cost in its tariff and GTOP?

A. Yes, but for the reason stated above, the Company proposes to address this in language added to P.S.C. No. 9 - General Information Section 29 and generalized GTOP language.

Q. Please describe the language that the Company would propose adding to P.S.C. No. 9 - General Information Section 29 and GTOP?

A. The proposed language would generally state that 1) with daily balancing, the Daily Index Purchase Price is the actual gas cost for purchases or sales, and 2) Surcharges to the price applied for sale of gas to a customer by a Company due to an under-delivery and discounts applied to the price credited to a customer for sale of gas to a Company due to an over-delivery are classified as penalties.

Q. Would there be any other tariff changes in response to the recommendations in Staff's testimony?

A. The Company reserves the right to revise other language in its tariff to conform or otherwise remove any inconsistencies or ambiguities resulting from the changes proposed herein.

Q. Does that conclude your rebuttal to the testimony prepared by Staff Gas Policy & Supply Panel?

A. Yes, at this time.

A.L.J. LECAKES: Exhibits attached to the testimony?

MR. NICKSON: There are four exhibits attached to the direct testimony of The Tariff Reorganization Panel which were identified as TRP1 through TRP4 and I ask that they be marked for identification.

A.L.J. LECAKES: They will be marked as TRP1 Exhibit 99, TRP2 Exhibit 100, TRP3 Exhibit 101, and TRP4 Exhibit 102. Next witness panel?

MR. NICKSON: The next panel is the company's Volumetric Forecast Panel consisting of Eric H. Minal and Sophia S. Cruz. The company's Volumetric Forecast Panel prepared testimony entitled The Direct Testimony of The Volumetric Forecast Panel which consists of 37 pages of questions and answers. The Volumetric Forecast Panel also prepared a rebuttal testimony entitled The Rebuttal Testimony of The Volumetric Forecast Panel which consists of 11 pages of questions and answers and I ask that the direct and rebuttal testimony of The Volumetric Forecast Panel be incorporated into the record as if given orally today. `

A.L.J. LECAKES: Granted. The Volumetric Forecast Panel Direct Testimony in the company Direct Testimony should be copied in now and then The Volumetric

Forecast Panel Rebuttal Testimony should follow. Did Mr. Minal sign this? Yes. Is Mr. Minal appearing in his capacity as an individual witness for cross examination or was cross examination waived for him?

MR. NICKSON: I believe Mr. Minal is appearing as a witness as an individual witness as well as part of the Cost of Service Rate Design Panel.

A.L.J. LECAKES: Okay. So he will be sworn in separately apart from the affidavit?

MR. NICKSON: Yes, Your Honor.

A.L.J. LECAKES: Okay. Were there any exhibits -- I'm sorry. The affidavit will be marked as Exhibit 103.

DIRECT TESTIMONY OF VOLUME FORECAST PANEL

1 Q. State your name and business address.

2 A. My name is Eric H. Meinl, and my business address is 6363 Main
3 Street, Williamsville, New York 14221.

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

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

8 Q. Have you provided your educational and professional experience
9 elsewhere in this proceeding?

10 A. Yes, I have provided this information in the Direct Testimony of Eric
11 H. Meinl filed in this case.

12 Q. State your name and business address.

13 A. My name is Sofia S. Cruz, and my business address is 6363 Main
14 Street, Williamsville, New York 14221.

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

16 A. I am employed by National Fuel Gas Distribution Corporation
17 ("Distribution" or the "Company") as Director in the Rates and
18 Regulatory Affairs Department.

19 Q. State briefly your educational and professional experience.

20 A. I graduated from Canisius College, Buffalo, New York in May 1987,

with a Bachelor of Science degree in Accounting. I also received certification in Cobol programming from Bryant and Stratton College, Buffalo, New York in December 1987.

In November 1992, I began my employment at the Company as an Associate Programmer Analyst in the Information Services Department. In October 1994, I was promoted to Programmer Analyst I and subsequently promoted to Programmer Analyst II in July 1996 and Systems Analyst in March 2003. While in Information Services, I worked in the areas of Revenue/Receivables, Meter Reading, Collections and Quality Assurance. In March 2008, I transferred to the Rates and Regulatory Affairs Department as an Assistant Manager. In September 2011 I was promoted to Director, my current position.

Q. Have you testified previously?

A. Yes. I have testified on behalf of the Company before the Pennsylvania Public Utility Commission in its Purchased Gas Costs - 66 Pa. C.S. Section 1307(f) proceedings regarding volumetric forecasting.

Q. What is the subject of your testimony?

A. We are presenting the Company's volume forecast of Rate Year

1 throughput (retail sales and transportation service). Additionally,
2 we are testifying to the updated lost and unaccounted for factor
3 pursuant to Staff's Whitepaper on Lost and Unaccounted for Gas.
4 Q. Please provide a general overview of the Company's throughput
5 forecast.
6 A. Each year, for system planning purposes, the Company prepares a
7 five year Master Estimate to forecast natural gas consumption of its
8 sales and transportation customers. The Company has based the
9 forecast of sales and transportation volumes and the number of
10 customers used in this proceeding on its most recently completed
11 Master Estimate. The Company's Master Estimate segments its
12 market into residential, commercial, public authority and industrial
13 categories. The Master Estimate provides monthly sales and
14 transportation volumes and the number of customers on a fiscal
15 year (12 months ended September) time frame. The industrial
16 category is further segregated into small and large volume
17 categories using a throughput limit of 55,000 Mcf/year. The
18 genesis of the 55,000 Mcf/year segregation was in response to a
19 Commission order availing transportation service to customers
20 consuming in excess of 55,000 Mcf/year. Although the volumetric

requirements for transportation service have been relaxed over the years, the 55,000 Mcf /year breakpoint remains a legitimate segmentation between large and small volume industrial customers.

Q. Please describe how the residential, commercial, public authority and small industrial customer classes are forecasted.

A. The residential, commercial, and public authority classes are segregated into use per account and number of accounts. The use per account forecast is determined using econometric models, which describe average annual usage as a function of one or more economic explanatory variables. The forecasted number of accounts is projected to remain at the historic level. An estimate of number of accounts expected to be served by marketers is subtracted from the total number of customers yielding retail customers. Projected throughput for each of the classes is the product of monthly use per account and the number of accounts. The forecasted volumes for the small industrial sector are projected to remain constant at historic levels of consumption on a throughput basis.

DIRECT TESTIMONY OF VOLUME FORECAST PANEL

1 Q. Please describe how the large volume industrial customer category
2 is forecasted.
3 A. The large volume industrial sector (greater than 55,000 Mcf/year)
4 consists of 60 customers. Each customer is contacted by the
5 appropriate major account representative of the Energy Services
6 Department to determine their annual usage, on a throughput
7 basis, over a six-year horizon. The large volume industrial
8 customers are asked to estimate their usage, paying particular
9 attention to any events that may alter their estimated future
10 consumption levels. In addition to these large industrial customers
11 there is one large commercial customer that has been forecasted
12 based on the surveys conducted by our Energy Services
13 Department. This commercial customer has been added to the
14 commercial forecast. The large volume forecasting process
15 includes an assessment of significant load changes, which is based
16 on input and data provided to the Rates and Regulatory Affairs
17 Department, by both the Engineering Services and Energy Services
18 Departments. This process of assessing significant load changes
19 is consistent with Distribution's implementation action steps taken
20 in response to recommendations IX-1 (#60) and IX-2 (#61) from the

2013 Management Audit completed by Schumaker & Company (Case No. 11-G-0580).

Q. Please explain Exhibit ___(VFP-1) and Exhibit___(VFP)-2.

A. Exhibit ___(VFP-1) provides a summary of the volumetric forecast included in the current Master Estimate for each fiscal year. Exhibit ___(VFP-2) provides a summary of the customer count forecast included in the current Master Estimate for each fiscal year.

Q. Please describe Exhibit ___(VFP-1), Schedule 1 and Exhibit ___(VFP-2), Schedule 1.

A. Exhibit ___(VFP-1), Schedule 1 is a schedule that contains the projected throughput volumes by residential, commercial, industrial and public authority revenue classes. Exhibit ___(VFP-2), Schedule 1 is a schedule that contains the projected number of customers by residential, commercial, industrial and public authority revenue classes.

Q. Please describe Exhibit ___(VFP-1), Schedule 2 and Exhibit ___(VFP-2), Schedule 2 .

A. Exhibit ___(VFP-1), Schedule 2 is a schedule that segregates revenue class throughput into retail sales volumes and transportation service by service class. Exhibit ___(VFP-2),

1 Schedule 2 is a schedule that segregates revenue class customers
2 into retail sales volumes and transportation service by service class
3 within each revenue class.
4 Q. Please describe Exhibit ___(VFP-1), Schedule 3 and Exhibit
5 ___(VFP-2), Schedule 3.
6 A. Exhibit ___(VFP-1), Schedule 3 shows the retail sales projection by
7 revenue class and tariff service class. Exhibit ___(VFP-2),
8 Schedule 3 shows the retail customer count projection by revenue
9 class and tariff service class.
10 Q. Please describe Exhibit ___(VFP-1), Schedule 4 and Exhibit
11 ___(VFP-2), Schedule 4.
12 A. Exhibit ___(VFP-1), Schedule 4 shows residential transportation
13 service class volume projection. Exhibit ___(VFP-2), Schedule 4
14 shows residential transportation service class customer count
15 projection.
16 Q. Please describe Exhibit ___(VFP-1), Schedule 5 and Exhibit
17 ___(VFP-2), Schedule 5.
18 A. Exhibit ___(VFP-1), Schedule 5 shows the commercial
19 transportation service class volume projection. Exhibit ___(VFP-2),
20 Schedule 5 shows the commercial transportation service class

1 customer projection.

2 Q. Please describe Exhibit ___(VFP-1), Schedule 6 and Exhibit

3 ___(VFP-2), Schedule 6.

4 A. Exhibit ___(VFP-1), Schedule 6 shows the industrial transportation

5 service class volume projection. Exhibit ___(VFP-2), Schedule 6

6 shows the industrial transportation service class customer

7 projection.

8 Q. Please describe Exhibit ___(VFP-1), Schedule 7 and Exhibit

9 ___(VFP-2), Schedule 7.

10 A. Exhibit ___(VFP-1), Schedule 7 shows the public authority

11 transportation service class volume projection. Exhibit ___(VFP-2),

12 Schedule 7 shows the public authority transportation service class

13 customer projection.

14 Q. Please describe Exhibit ___(VFP-3), Schedule 1.

15 A. Exhibit ___(VFP-3), Schedule 1 is a schedule, using the residential

16 class only for example purposes, that summarizes actual

17 throughput, number of accounts, actual consumption per account,

18 actual and normal degree days, normal throughput, and normal

19 consumption per account for the residential class for the twelve

20 months ended December 2015. It also shows the dates the billing

cycles were read for the year.

Q. Please summarize the technique employed to project the levels of throughput volumes contained in Exhibit ___(VFP-1).

A. The residential, commercial and public authority forecasts were segregated into separate forecasts of use per account and number of accounts. The throughput projection for these classes is derived using econometric models, which describe average annual use per account (dependent variable) as a function of one or more economic explanatory variables (independent variables). The independent variables used in the econometric model were actual monthly heating degree days and the monthly average price of gas per Mcf (lagged 12 months).

Q. How is customer usage accumulated on a monthly basis?

A. Customers are billed throughout the month on a 21-cycle basis. Page 7 of Exhibit ___(VFP-3), Schedule 1 illustrates the manner in which meters were read throughout the months and the dates the billing cycles were read for the twelve months ended December 2015. To explain further, using November 2015 as an example, control 10 (or billing cycle 10) was read on November 11, 2015. In October 2015, the same control was read on October 13, 2015.

1 Customer usage for control 10 of November 2015 would be the
2 difference between the meter read on October 13, 2015 and
3 November 11, 2015. Actual and normal degree days are also
4 accumulated for control 10 of November 2015 starting with October
5 14 (the day after control 10 was read for October 2015) through
6 November 11, 2015.
7 Q. Please describe how the dependent variable, average annual use
8 per account, is specified for use in the models.
9 A. Using residential billing data for the Historic Test Year (twelve
10 months ended December 2015), Exhibit ___(VFP-3), Schedule 1,
11 Pages 1 through 3 show in summary format an example of how the
12 dependent variable, average annual actual use per account, is
13 developed. Page 1 shows the actual throughput consumption for
14 each billing cycle. Page 2 shows the number of accounts for each
15 billing cycle and page 3 shows the actual usage per account by
16 billing cycle. The monthly average is summed for the 21 billing
17 cycles to generate the annual actual use per account. This result,
18 105.803, represents the dependent variable.
19 Q. What do pages 4 through 6 of Exhibit___(VFP-3), Schedule 1
20 provide?

A. Each billing cycle is individually "normalized" for weather using its cycle bill specific actual and normal degree days shown on page 4. Page 4 also shows how the degree day variable is specified by using the annual average of the 21 billing cycles which represents the independent variable, degree days. The term "degree day", as used here, is the amount by which 65 degrees F exceeds the average of the high and low temperatures for any day. The degree day concept assumes that a customer's heating equipment is utilized when the average daily temperature is below 65 degrees F.

The monthly normalized throughput by billing cycle is shown on Page 5, which are summed to a monthly and annual total. Page 6 shows the monthly normalized usage per account by billing cycle and summed to a monthly and annual use per account. The annual normalized use per account is used for forecast validation purposes. Pages 4 through 6 are in summary format. The detail is included in Exhibit ___(VFP-3), Schedule 3 which is described later.

Q. What level of normal degree days was used to develop the projected throughput volumes as well as the normalization calculation?

A. The level of degree days used to develop the projected throughput volumes (as well as the normalization calculation) in this proceeding is 6,617.

Q. What is basis for this level of normal degree days?

A. The normal degree day level of 6,617 was calculated by the National Oceanic Atmospheric Administration (NOAA) for Buffalo Niagara International. The normal degree days are shown on Exhibit ___(VFP-3), Schedule 2, Page 4 of 4.

Q. Please describe the data specification of the gas price variable.

A. The natural gas price is an average revenue price expressed in 2009 dollars as adjusted by the Gross Domestic Product ("GDP") chained price index. The GDP chained price index, was projected in the Blue Chip Economic Indicators, Vol. 40, No. 3, dated March 10, 2015. The natural gas price used is the price lagged 12 periods. The price variable is specified in this form in order to measure lags in customer response to changes in price.

Q. Please explain why separate forecasts are specified for use-per-account and the number of accounts.

A. Each of these components of total consumption is influenced by different factors, which must be analyzed separately. Breaking total

consumption into these components builds more structure into the analysis of the determinants of gas consumption. The greater structure afforded by separate analyses of use-per-account and number-of-accounts is desirable for both model specification and forecast validation purposes. With respect to model specification, from economic theory we expect customer usage of a product to be influenced by the price of the product and, in the case of natural gas, weather.

Q. Why have you chosen econometric modeling to forecast use-per-account?

A. The word "Econo-metric" means measuring economic relationships. The technique of econometric modeling incorporates hypotheses from economic theory and statistical tests of those hypotheses. The economic theory of consumer behavior, for example, postulates that the price of natural gas, weather and consumer preference are major determinants of household natural gas usage. Econometric techniques, such as regression analysis, allow for testing of these hypotheses and measurement of the relative impact of each postulated determinant on natural gas usage.

Q. What criteria did you use to select the final forecast equations for the

residential, commercial and public authority categories?

A. The forecast equations were developed using regression analysis. The following criteria were used to evaluate each estimated equation: (1) the signs and magnitudes of the estimated coefficients of each potential explanatory variable; (2) the adjusted coefficient of determination, or R-squared, which is an indication of the explanatory power of the equation; (3) the t-ratios which test the significance of a particular coefficient; (4) the Durbin-Watson statistic, which tests for serial correlation in the residuals; and (5) the standard error of the regression, which is an additional measure of the explanatory power of the equation.

Q. What was the first consideration used to evaluate each estimated equation?

A. The fundamental criterion used to evaluate potential forecast equations was to reject any equation, which included variables with coefficients whose signs were contrary to economic theory. From economic theory, we would expect the level of economic activity and heating degree days to have positive impacts on natural gas usage. These variables then should have positive coefficient estimates. We would also expect, based upon economic theory, that increases to

the price of natural gas would have a negative impact on natural gas usage. This variable should have a negative coefficient estimate.

Q. Please describe the other statistics used to evaluate each estimated equation.

A. The adjusted coefficient of determination, R-squared, indicates the percentage of past movement in natural gas usage which is explained by the estimated equation. The highest coefficient of determination indicates the equation, which explains the largest percentage of the past movement in gas usage. Other statistics used to evaluate the estimated forecast equations were the t-ratios and the Durbin-Watson ("D-W") statistic.

The t-ratio was calculated for each explanatory variable in the estimated equations. The t-ratio is calculated as a variable's estimated coefficient divided by the associated standard error. As a general rule, the coefficient is statistically significant if the absolute value of the t-ratio is 2.0 or greater.

The D-W statistic tests for the presence of a pattern (i.e., serial correlation) in the residuals. A residual is the difference between the actual value of an observation and the corresponding fitted value from the regression equation. A fundamental assumption of

1 regression analysis is that the residual is randomly distributed (i.e.,
2 not correlated). Generally speaking, the D-W statistic will be close to
3 2.0 if the residuals are not serially correlated.
4 Q. Please describe the residential use per account throughput forecast.
5 A. The residential use per account throughput forecast was derived by
6 creating a model utilizing rolling annual billing month degree days
7 and residential real gas price lagged 12 periods. The statistical
8 output from the model is shown on Exhibit ___(VFP-4), Schedule 1,
9 Page 1 of 6. The variables used in the model, both historic and
10 projected, are shown on pages 2 through 6 of Exhibit ___(VFP-4),
11 Schedule 1. The data stream spans the period January 2000
12 through December 2014 (180 observations).
13 Q. Please describe the results of the residential use-per-account
14 model.
15 A. The regression results show that rolling billing month degree days
16 (NYDEGREEDAYS), and residential real gas price lagged 12 periods
17 [NYRESPRICE(-12)], are statistically-significant determinants of
18 average use-per-account, with t-values at 71.27, and -4.19,
19 respectively. Corresponding to economic theory, each variable has
20 the expected sign, i.e., positive on degree days and negative on the

price variable. The adjusted coefficient of determination, R-squared, is .999, which indicates the model explains 99.9 percent of the observed variation in use-per-account. The standard error of the regression is 0.26% and the D-W statistic is 2.13.

Q. How is the annual residential projection from the model transformed into monthly data?

A. Forecasted annual usage per account is provided in the econometric model output found on pages 2 through 6 of Exhibit ___(VFP-4), Schedule 1 in the column labeled NYRESMCFPEF. The forecasted usage per account for each of the 12 months ended December 2015 through 2020 were input into Exhibit __(VFP-4), Schedule 2, Page 1 of 8, and can be found in column C, rows 21 through 26. Page 1 of 8 of Exhibit___ (VFP-4), Schedule 2 shows the annual residential projections are then allocated into monthly usage per account using a five-year historic average of monthly residential normalized consumption, as shown in Block A. For example, January 2015 projection of 18.428 Mcf (column C, row 31) per account equals 0.17263 (January is 17.2563% of the annual average, column C, row 16) multiplied by the annual Mcf per account projection of 106.75 (column C, row 21). The annual

1 projection is the sum of the twelve monthly projections.

2 Q. Please describe the residential number of customers projection.

3 A. The number of customers projection for the residential class is

4 projected to remain constant at the twelve months ended

5 December 2014 level. Like the annual projected use per account,

6 the annual projection of accounts is allocated into monthly

7 customer counts using the five-year average of the historic monthly

8 number of accounts. This is shown for the residential class on

9 Exhibit ___(VFP-4), Schedule 2, Page 5 of 8 in the area marked

10 Block B. The annual number of accounts is the average of the

11 monthly customer accounts.

12 Q. Please describe the projected residential monthly throughput.

13 A. The projected monthly throughput is the product of the projected

14 Mcf per account and number of accounts as shown on Exhibit

15 ___(VFP-4), Schedule 2, Page 1 of 8 in the area marked Block G.

16 The remaining pages of Exhibit__ (VFP-4), Schedule 2 provide a

17 summary of the breakdown of residential consumption by service

18 class.

19 Q. Please describe Exhibit __ (VFP-4) Schedule 3.

20 A. Exhibit __ (VFP-4) Schedule 3 provides the adjustments for

1 forecasted annual consumption by leap year.

2 Q. Please describe Exhibit __ (VFP-4) Schedule 4.

3 A. Exhibit __ (VFP-4) Schedule 4 allocates the total residential

4 consumption to the billing service classes that residential

5 customers are forecasted to be billed under and as summarized in

6 Exhibit ___(VFP-1), Schedule 1.

7 Q. Please describe the commercial use per account throughput forecast.

8 A. The commercial use per account throughput forecast was derived

9 by creating a model utilizing rolling annual average billing month

10 degree days, and commercial real gas price lagged 12 periods as

11 independent variables used to explain the dependent variable, use

12 per account. The statistical output from the model is shown on

13 Exhibit ___(VFP-5), Schedule 1, Page 1 of 6. The variables used

14 in the model, both historic and projected, are shown on pages 2

15 through 6 of Exhibit ___(VFP-5), Schedule 1. The data stream

16 spans the period January 2000 through December 2014 (180

17 observations).

18 Q. Please describe the results of the commercial use-per-account

19 model.

A. The regression results show rolling billing month degree days (NYDEGREEDAYS) and commercial real gas price lagged 12 periods [NYCOMPRICE(-12)] are statistically-significant determinants of average use-per-account, with t-values at 32.35 and –6.4911, respectively. Corresponding to economic theory, each variable has the expected sign, i.e., positive on degree days and negative on gas price. The adjusted coefficient of determination, R-squared, is .997, which indicates the model explains 99.7 percent of the observed variation in use-per-account. The standard error of the regression is 0.42% and the D-W statistic is 2.25.

Q. How is the annual commercial projection from the model transformed into monthly data?

A. Forecasted annual usage per account is provided in the econometric model output found on pages 2 through 6 of Exhibit ___(VFP-5), Schedule 1 in the column labeled NYCOMMCFPEF. The forecasted usage per account for each of the 12 months ended December 2015 through 2020 were input into Exhibit __(VFP-5), Schedule 2, Page 1 of 6, and can be found in column C, rows 21 through 26. Page 1 of 6 of Exhibit___ (VFP-5), Schedule 2 shows the annual commercial projections are then allocated into monthly

usage per account using a five-year historic average of monthly commercial normalized consumption, as shown in Block A. For example, January 2015 projection of 88.283 Mcf (column C, row 31) per account equals 0.16090 (January is 16.090% of the annual average, column C, row 16) multiplied by the annual Mcf per account projection of 548.68 (column C, row 21). The annual projection is the sum of the twelve monthly projections.

Q. Please describe the commercial number of customers projection.

A. The number of customers projection for the commercial class is projected to remain constant at the twelve months ended December 2014 level. Like the annual projected use per account, the annual projection of accounts is allocated into monthly customer counts using the five-year average of the historic monthly number of accounts. This is shown for the commercial class on Exhibit ___(VFP-5), Schedule 2, Page 4 of 6 in the area marked by block B. The annual number of accounts is the average of the monthly customer counts.

Q. Please describe the projected commercial monthly throughput.

A. The projected monthly throughput is the product of the projected Mcf per account and number of accounts as shown on Exhibit

___(VFP-5), Schedule 2, Page 1 of 6 in the area marked Block G. The remaining pages of Exhibit__ (VFP-5), Schedule 2 provide a summary of the breakdown of commercial consumption by service class.

Q. Please describe Exhibit __ (VFP-5) Schedule 3.

A. Exhibit __ (VFP-5) Schedule 3 provides the adjustments for forecasted annual consumption by leap year.

Q. Please describe Exhibit __ (VFP-5) Schedule 4.

A. Exhibit __ (VFP-5) Schedule 4 allocates the total commercial consumption to the billing service classes that commercial customers are forecasted to be billed under and as summarized in Exhibit ___(VFP-1), Schedule 1.

Q. Were there any additional commercial volumes added to the forecast?

A. Yes. A large volume commercial account was forecasted individually and added to the forecast. This was a result of the audit recommendation that significant additions to services be added to the forecast after review with the Energy Services and Engineering departments. This is identified on Block I of Exhibit__(VFP-5) Schedule 2.

Q. Please describe the public authority use per account throughput forecast.

A. The public authority use per account throughput forecast was derived by creating a model utilizing rolling annual average billing month degree days, and public authority real gas price lagged 12 periods as independent variables used to explain the dependent variable, use per account. The statistical output from the model is shown on Exhibit ___(VFP-6), Schedule 1, Page 1 of 6. The variables used in the model, both historic and projected, are shown on pages 2 through 6 of Exhibit ___(VFP-6), Schedule 1. The data stream spans the period January 2000 through December 2014 (180 observations).

Q. Please describe the results of the public authority use-per-account model.

A. The regression results show rolling billing month degree days (NYDEGREEDAYS) and public authority real gas price lagged 12 periods [NYCOMPRICE(-12)] are statistically-significant determinants of average use-per-account, with t-values at 17.27 and –3.68, respectively. Corresponding to economic theory, each variable has the expected sign, i.e., positive on degree days and negative on gas

price. The adjusted coefficient of determination, R-squared, is .993, which indicates the model explains 99.3 percent of the observed variation in use-per-account. The standard error of the regression is 0.61% and the D-W statistic is 2.09.

Q. How is the annual public authority projection from the model transformed into monthly data?

A. Forecasted annual usage per account is provided in the econometric model output found on pages 2 through 6 of Exhibit ___(VFP-6), Schedule 1 in the column labeled NYPUBMCFPEF. The forecasted usage per account for each of the 12 months ended December 2015 through 2020 were input into Exhibit __(VFP-6), Schedule 2, Page 1 of 6, and can be found in column C, rows 21 through 26. Page 1 of 6 of Exhibit___ (VFP-6), Schedule 2 shows the annual public authority projections are then allocated into monthly usage per account using a five-year historic average of monthly public authority normalized consumption, as shown in Block A. For example, January 2015 projection of 526.958 Mcf (column C, row 31) per account equals 0.16362 (January is 16.362% of the annual average, column C, row 16) multiplied by the annual Mcf per account projection of 3220.62 (column C, row

21). The annual projection is the sum of the twelve monthly projections.

Q. Please describe the public authority number of customers projection.

A. The number of customers projection for the public authority class is projected to remain constant at the twelve months ended December 2014 level. Like the annual projected use per account, the annual projection of accounts is allocated into monthly customer counts using the five-year average of the historic monthly number of accounts. This is shown for the public authority class on Exhibit ___(VFP-6), Schedule 2, Page 4 of 6 in the area marked by block B. The annual number of accounts is the average of the monthly customer counts.

Q. Please describe the projected public authority monthly throughput.

A. The projected monthly throughput is the product of the projected Mcf per account and number of accounts as shown on Exhibit ___(VFP-6), Schedule 2, Page 1 of 6 in the area marked Block G. The remaining pages of Exhibit__ (VFP-6), Schedule 2 provide a summary of the breakdown of public authority consumption by service class.

Q. Please describe Exhibit __ (VFP-6) Schedule 3.

A. Exhibit __ (VFP-6) Schedule 3 provides the adjustments for forecasted annual consumption by leap year.

Q. Please describe Exhibit __ (VFP-6) Schedule 4.

A. Exhibit __ (VFP-6) Schedule 4 allocates the total public authority consumption to the billing service classes that public authority customers are forecasted to be billed under and as summarized in Exhibit ___(VFP-1), Schedule 1.

Q. Please explain the industrial forecast.

A. The industrial customers are segregated into small and large volume using 55,000 Mcf per year as the throughput limit. The genesis of the 55,000 Mcf per year segregation was in response to a Commission order availing transportation service to customers consuming in excess of 55,000 Mcf per year. Although the volumetric requirements for transportation service have been relaxed over the years, the 55,000 Mcf breakpoint remains a legitimate segmentation point between large and small volume industrial customers. Industrial accounts with volumes in excess of 55,000 Mcf per year were extracted from the historic database and forecasted individually.

Q. Please describe the small volume industrial forecast.

A. At present, we do not forecast small industrial customers using an econometric model. Total throughput and number of accounts to the small industrial customers (consuming less than 55,000 Mcf per year) is projected to remain at the twelve months ended December 2014 level. Exhibit ___ (VFP-7), Schedule 1, Page 1 of 4 shows the annual small industrial projection allocated into monthly usage using a five-year historic average of monthly small industrial consumption, as illustrated in Block A. For example, January 2015 small volume industrial throughput projection of 522,642 Mcf (column C, row 33) equals .13057 (January is 13.057% of the annual usage, column c, row 18) multiplied by the annual Mcf projection of 4,002,770.1 (column O, row 38).

Q. Please describe the small industrial number of customers projection.

A. The number of customers projection for the small industrial group is projected to remain constant at the twelve months ended December 2014 level. Like the annual projected throughput, the annual projection of number of accounts is allocated into monthly customer counts using the five-year average of the historic monthly

number of accounts. This is shown for the class on Exhibit ___(VFP-7), Schedule 1, Page 3 of 4 in the area marked Block B. The annual number of accounts is the average of the monthly customer counts.

Q. Please describe Exhibit __ (VFP-7) Schedule 2.

A. Exhibit __ (VFP-7) Schedule 2 provides the adjustments for forecasted annual consumption by leap year.

Q. Please describe Exhibit __ (VFP-7) Schedule 3.

A. Exhibit __ (VFP-7) Schedule 3 allocates the total small industrial consumption to the billing service classes that small industrial customers are forecasted to be billed under and as summarized in Exhibit ___(VFP-1), Schedule 1.

Q. Please describe the large volume industrial forecast.

A. The large Industrial customers consist of industrial customers consuming greater than 55,000 Mcf per year. All customers in the large industrial group were individually forecasted based upon information provided by the customer in cooperation with the appropriate Distribution Energy Services sales representative, who is the closest liaison between the Company and the customer and is the individual in the Company most aware of each customer's

1 energy requirements.

2 Q. How many large volume industrial forecasts were prepared?

3 A. A total of 60 forecasts were prepared. These are presented in

4 Exhibit___(VFP-7), Schedule 4. It should be noted that one

5 customer (the SC 21 Large Electric Generation Customer) was

6 excluded from the revenue projection in the rate year since the

7 potential customer forecasted at the time of the preparation of the

8 Master Estimate has abandoned the service territory.

9 Q. What assumptions were used in the preparation of the large volume

10 industrial forecasts?

11 A. The Energy Services representatives contacted each large volume

12 customer to determine their annual usage for calendar 2015 through

13 2020. Customers were asked to assume that: the same tariff

14 classifications that existed during the historic test year would continue

15 through the rate year; gas supply would be sufficient to meet all

16 requirements; and, the same relative pricing (i.e., oil and gas price

17 spreads) that occurred during calendar 2015 would continue through

18 2020. Based on these assumptions and their historic usage,

19 customers were asked to estimate their future usage. Customers

20 were also directed to pay particular attention to any factors that might

1 cause their historic usage levels to change including, but not limited
2 to, changes in usage levels or production.
3 Q. Did the assumptions employed in the large volume industrial
4 forecasts include an estimate of losses due to competition from other
5 sources of natural gas?
6 A. No. We have, however, considered this competition in our overall
7 rate design.
8 Q. Why did the Energy Services representatives prepare the individual
9 forecasts that form the basis for the large volume sales projection?
10 A. The Energy Services representative is the closest liaison between
11 Distribution and these customers, and is the person most aware of
12 each individual customer's energy use decisions.
13 Q. How were the annual large volume industrial forecasts projected on a
14 monthly basis?
15 A. The total annual forecasts were distributed into monthly projections
16 utilizing calendar 2014 monthly distributions.
17 Q. Do the Company's throughput forecasts recognize customer
18 conservation?
19 A. Yes. The individual forecasts for accounts consuming in excess of
20 55,000 Mcf per year recognize the most recent energy use decisions

of those companies. Conservation is one component of those decisions.

Q. Please describe Exhibit ___(VFP-3), Schedule 2.

A. Exhibit ___(VFP-3), Schedule 2, Pages 1 through 4 show in summary format the residential, public authority, and public authority throughput normalization schedules for the twelve months ended September 2006. Page 4 shows the normal degrees days calculated by NOAA.

Q. Please describe Exhibit ___(VFP-3), Schedule 3.

A. Exhibit ___(VFP-3), Schedule 3 is a twenty-two page schedule that uses the residential class as an example of how actual consumption is normalized for weather and used for forecast validation purposes. Pages 2 through 22 show each individual billing cycle's normalization calculation. Page 1 shows the summary for the 21 billing cycles including the annual normal Mcf per account, number of accounts, and normalized throughput which are used for forecast validation purposes.

Q. How is actual consumption adjusted for the effects of weather?

A. The normalization process for each billing cycle is accomplished in the following steps. Using billing cycle 10 or control 10 (Page 11 of 22) as an example, the monthly actual consumption and number of

accounts is identified in columns 1 and 2. Actual consumption per account is the division of columns 1 and 2 shown in column 3. The monthly base volume per account (column 4) is that portion of the total consumption that does not change with changes in temperature and is not heat-sensitive. For the twelve months ended December 2015, the representative monthly base volume calculation is based on the average of the two lowest consecutive months of July and August. The monthly base volume per account is then subtracted from the actual monthly consumption per account to determine the actual heating load per account (column 5).

Next, heating consumption per degree day (column 7) is determined by dividing the actual gas heating load consumption (column 5) by the actual monthly billing degree days experienced for that billing cycle or control (column 6). The normalized heating usage per account (column 9) is derived by multiplying the heating use per degree day (column 7) by the monthly normal degree days associated with each particular billing cycle or control (column 8). The monthly base volume per account (column 4) is then added to the monthly normalized heating usage per account (column 9) to

1 derive the monthly normal consumption per account (column 10).
2 The monthly normalized consumption (column 11) is derived by
3 multiplying the normal usage per account (column 10) by the
4 monthly number of accounts (column 2).
5 Q. How is the normalization calculation summarized for the 21 billing
6 cycles?
7 A. Exhibit ___(VFP-3), Schedule 3, Page 1 of 22 is the summary of
8 the 21 billing cycles for the residential throughput normalization
9 calculation. Columns 1, 2 and 11 are the sum of the 21 billing
10 cycles for actual Mcf, Accounts, and Normalized Mcf, respectively.
11 Like the normalization calculation for a single billing cycle, columns
12 3 through 5 are calculated in the same manner as an individual
13 billing cycle. The actual consumption per account (Column 3) is the
14 division of columns 1 and 2. The base Mcf per account is the
15 average of the two lowest consecutive months. The monthly base
16 volume is subtracted from the actual monthly consumption per
17 account to determine the actual heating load per account (Column
18 5). Actual degree days shown in column 6 represent the average
19 of the 21 billing cycles. Column 7, heating consumption per degree
20 day per account is computed in the same manner as a single billing

cycle, by dividing actual heat per account (column 5) by the actual degree days (column 6). Normal degree days shown in column 8 represent the average of the 21 billing cycles. The calculation for the average of the actual and normal degree days is illustrated on Exhibit ___(VFP-3), Schedule 1, Page 4 of 7.

As discussed earlier, columns 1, 2 and 11 on the summary page (Exhibit ___(VFP-3), Schedule 3, Page 1 of 22) represent the sum of the 21 individual billing cycles. Further, each billing cycle has its own customer profile as demonstrated in Exhibit ___(VFP-3), Schedule 1 specifically identified by the number of accounts (page 2) and the use per account (pages 3 and 6). As shown on page 3, the actual usage per account ranges from 92.762 Mcf (billing cycle 20) to 126.630 Mcf (billing cycle 1). On a normalized use per account basis, page 6, the range is 91.694 Mcf (billing cycle 20) to 125.282 Mcf (billing cycle 1). The range of consumption is primarily due to the different types of residential customers included in the residential class.

Q. Please explain.

A. Exhibit ___(VFP-3), Schedule 1, Page 6 shows residential normal consumption per account in summary format for the 21 billing

cycles. Certain billing cycles that have unusually large usage per account values (billing cycles 1 through 4, and 21) are more likely to contain public housing facilities or other residential customers that tend to use more gas than the average residential customer. Conversely, a billing cycle that has a small use per account (billing cycles 14-15, 17-20) are more likely to contain individually metered apartments or residential customers that tend to use less than the average residential customer.

Q. Why is it important to recognize that the individual billing cycle data is unique?

A. On its own, each billing cycle is the most correct calculation for the normalization process, however, when used for forecast validation of a class in total, the weighting of the 21 billing cycles is the most proper representation. The weighting calculation impact is shown in column 10 of Exhibit___(VFP-3), Schedule 3, Page 1, Normal Mcf per account.

Lost and Unaccounted For

Q. What is the Company's proposed Lost and Unaccounted for factor ("LAUF") in this proceeding?

A. The Company is proposing to update the LAUF pursuant to Staff's

Whitepaper on Lost and Unaccounted for Gas. Staff's Whitepaper recommended updating the LAUF used for calculating sales rates and transportation shrinkage in base rate cases based on the latest 5 year average of LAUF. Table VFP-1 below summarizes the most recent 5 year average LAUF rate.

Table VFP-1 5 Year Average LAUF Rate (12 Months Ended August)	
Year	Percent LAUF
2011	1.614%
2012	1.975%
2013	1.834%
2014	1.665%
2015	1.512%
Average	1.720%
Standard Deviation	0.028%

Based on this method the LAUF used for calculating sales rates and transportation shrinkage would decrease to 1.72% from 2.07%.

Q. Does this conclude your direct testimony?

A. Yes, at this time.

Case 16-G-0257 Rebuttal Testimony of Volumetric Forecast Panel

Q. State your name and business address.

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

Q. Have you provided testimony in this proceeding?

A. Yes I have provided Direct Testimony as part of the Volumetric Forecast Panel. I have also provided direct testimony individually and on a number of other panels.

Q. State your name and business address.

A. My name is Sofia S. Cruz, and my business address is 6363 Main Street, Williamsville, New York 14221.

Q. Have you provided testimony in this proceeding?

A. Yes I have provided Direct Testimony as part of the Volumetric Forecast Panel.

Q. Did any intervening parties to this case recommend changes to the Company's customer and volumetric forecasts?

A. Yes. The Staff Gas Rates panel recommended increases in the usage per account forecasts of the residential and commercial customer classes. Staff proposes increasing the Company's forecast of the number of accounts for the residential, commercial, and public

authority customer classes. Staff agrees with the Company's industrial customer class forecast.

Q. Do you agree with Staff's proposed customer count forecast for the residential and commercial customer classes?

A. No. Staff's forecast utilizes an unreasonably short (in number of years) trend analysis that, if consistently used from year to year, could result in extreme swings in forecasted customers.

Q. Please summarize the account forecasts for the residential and commercial customer classes for the 12 months ended March 2018.

A. Table VFP Rebuttal 1, provides a summary of Staff's and the Company's forecast of actual accounts compared to the twelve months ended March 2016.

Table VFP Rebuttal 1

Number of Accounts	Residential	Commercial
Staff 3 yr Trend 12 Months Ended 3/2018	495,422	33,578
Company 12 Months Ended 3/2018	484,680	32,392
Actual 12 Months Ended 3/2016	491,874	32,857
9 Yr Trend 12 Months Ended 3/2018	494,604	33,371

Q. The Company's forecast for the twelve months ended March 2018 is

below the current number of accounts. How did the Company develop its forecasted number of accounts?

A. The Company reviewed the number of accounts on its system for the 15 years of actual data used in its usage per account forecast. Exhibit___(VFP-8) provides graphs of the residential and commercial number of accounts used in its analysis. Page 1 of Exhibit___(VFP-8) provides a summary of residential accounts and page 2 provides a summary of commercial accounts. Actual account data for the rolling 12 months average number of accounts from January 2000 through December 2014 were used in the review. As can be seen from the first seven years of the graph, the number of accounts was decreasing during this period. More recent years have seen a rebound in the number of accounts. The fifteen year trend line included on the graph demonstrates that account growth over this 15 year time period was relatively flat.

Q. Hasn't the number of accounts been growing over the past nine years?

A. Yes, the number of accounts has been growing over the past nine years. We would not be opposed to using a growth forecast for

residential and commercial accounts using a longer term trend analysis such as nine years as opposed to Staff's three year time period used in their trend analysis.

Q. Why do you oppose using Staff's three year trend period?

A. We do not believe that Staff's three year trend analysis is of reasonably significant length to reflect longer term influences on the changes in the number of accounts that can be expected on the Company's system. This can be readily seen by comparing changes in the three year trend of customer account growth from Exhibit___(VFP-8). For example, using a three year trend from January 2005 through December 2007 would have resulted in a steeply declining forecast of number of accounts. Using longer term trend analysis should temper the extreme volatility in account growth projections that would result from reliance on shorter term trend analysis that would be overly influenced by short term issues such as recent economic conditions (recessions or expansionary growth) or changes in city practices regarding demolition of older homes.

Q. Staff also projected an increase in the public authority number of accounts. Do you agree with Staff's projection?

A. Yes.

Q. Did Staff make any other adjustments to the number of accounts forecast?

A. Yes. At page 17 of the Staff Gas Policy and Supply Panel testimony Staff states that ;

> Staff included additional growth, above the observed level of current trends, to coincide with the Company's Gas Enhancement pilot programs, as well as efforts to convert other non-customers near or on existing distribution mains. Staff's Gas Rates Panel customer forecast includes an additional 2,150 customers in the residential marketing group and an additional 350 customers in the commercial marketing group.

Staff provides no apparent basis for these amounts in its testimony, exhibits, or work papers provided in response to Company data requests. Staff's trend analysis of account growth includes number of accounts through April 2016. That period includes a number of accounts already added through the Company's gas expansion program. Since the historical data used in the trend analysis already includes accounts added under the gas expansion program, it is unreasonable to potentially double count those additions

by adding a speculative and unsupported additional number of accounts. Particularly since there is no basis in this record to add 2,500 additional accounts other than an overly aggressive estimate of customer additions associated with the Company's gas expansion pilot program.

Q Did Staff provide you with the basis for its 2,500 additional accounts to be added to the number of accounts forecasted based on Staff's trend analysis?

A. Staff appears to have used an aggressive forecasting approach equating conversion potential in the GEP pilot areas with conversions. Exhibit___(VFP-10) is a pending data request submitted to Staff. The Company is waiting on this outstanding data request response from Staff and the Company reserves the right to address this topic further in testimony or at hearings. While the Company does have a gas expansion pilot program in place and it is extending mainline to reach and attach pockets of potential customers, the actual conversion of customers takes time.

For example, Exhibit__(ESP-2) of the Company's Energy Services Panel's rebuttal testimony identifies a number of pilot areas including those in Wilson and Richmond, New York that were part of Phase I of the gas expansion pilot program that was started in 2015. As can be seen from this exhibit, the actual number of conversions to date is a fraction of the total potential number of homes. This is to be expected, since it takes time for customers to determine when the appropriate time is for them to replace their existing heating systems with natural gas.

Q. Staff's Gas Policy and Supply Panel proposes an incentive of one basis point for each 250 firm customers that are added above Staff's forecasted customer count. Do you agree with this proposal?

A. The Company would be agreeable to such an incentive provided that the customer growth target was reasonable. As explained in the Company's Cost of Service Study and Rate Design panel, there is a tremendous benefit available to households in the state that have access to natural gas.

It is reasonable to provide the Company with a positive incentive to attach as many customers as is practical on its system. The problem with Staff's proposal is that it sets an unreasonable threshold for customer growth since it adds 2,500 additional accounts to its rate year forecast of number of accounts which, as was demonstrated previously, is overly aggressive since it uses a three year trend analysis,

Q. Do you agree with Staff's recommended increase in the usage per account forecasts of the residential and commercial customer classes?

A. No. Similar to the customer account forecast, Staff uses an unreasonably short time period for developing their usage per account forecasts. Also, Staff ignores the important price variable in explaining changes in customer usage behavior over the past 15 years.

Q. Please summarize the usage per account forecasts for the residential and commercial classes of customer for the 12 months ended March 2018.

A Table VFP Rebuttal 2 provides a summary of Staff's and the Company's usage per account forecast compared to the twelve months ended March 2016.

Table VFP Rebuttal 2

Usage per Account (Mcf)	Residential	Commercial
Staff 12 Months Ended 3/2018	106.8	558.5
Company 12 Months Ended 3/2018	106.6	557.7
Actual 12 Months Ended 3/2016	103.6	549.0

Q. Please provide general description of the differences between the Company and Staff's forecasts?

A. Staff's forecast used 3 years of usage data while the Company's forecast used 15 years worth of data. Staff used a regression model that used monthly consumption and actual degree days over a three year time period. Staff's model assumes that changes in customer usage are solely due to changes in heating degree days. The Company's forecast used a regression model that included heating degree days as well as a price variable to explain changes in customer usage. Exhibit VFP-9 provides a graphical summary of actual weather normalized consumption per account compared to the

average price of gas experienced from January 2000 through December 2014. The graphs also provide Staff and the Company's usage per account forecast as well as actual usage per account information through April 2016.

Q. What can be concluded from the graphs presented in Exhibit VFP-9?

A Both the Company and Staff's forecast appear overly aggressive in projecting usage per account growth, compared to current actual usage per account for the residential and commercial customer classes, although the Company's forecast is slightly less aggressive in forecasting account usage growth compared to Staff. What is also apparent from the graphs is the importance of the changes in price in explaining changes in usage per account over time. As can be seen from the graph, from January 2000 through approximately January 2011 there was a steady decline in customer usage per account. However, more recent years experienced a rebound in usage per account. The explanation for this rebound was the dramatic drop in the real price of gas paid by customers for natural gas service. This is consistent with economic supply and demand theory where the consumption of any good or service will move inversely with the

change in price. As the price of gas has declined, usage has increased. By ignoring the price variable, and only using the changes in actual heating degree days experienced over the past three years, Staff's forecast completely ignores how price will affect customer usage.

Staff's usage per account forecast is greater than both the current actual usage per account for residential and commercial customer classes and the Company's forecasted usage per account. Staff's overly aggressive forecasted increases for usage per account should be rejected. Indeed, given that current usage per account consumption for the residential and commercial class of customers is significantly less than even the Company's forecast, and because major declines in natural gas prices are not likely to occur, it would be more reasonable to use current actual normalized usage per account than either the Company's or Staff's forecast to estimate the consumption of residential and commercial customers in this case.

Q. Does this conclude your rebuttal testimony?

A. Yes, at this time.

A.L.J. LECAKES: Were there any exhibits attached to The Volumetric Forecast Panel?

MR. NICKSON: Yes, Your Honor. There were seven exhibits attached to the direct testimony identified as VFP-1 through VFP-7 and there were three exhibits attached to the rebuttal testimony of The Volumetric Forecast Panel identified as VFP-8 through VFP-10 and I ask that each of those documents be marked for identification.

A.L.J. LECAKES: VFP-1 will be 103, VFP-2 104, VFP-3 105, VFP-4 106 -- start over with VFP-1 will be Exhibit 104, VFP-2 will be Exhibit 105 now, VFP-3 will be Exhibit 106, VFP-4 will be 107 -- thank you again, VFP-5 now will be Exhibit 108, VFP-6 will be Exhibit 109, VFP-7 Exhibit 110, and then VFP-8 will be Exhibit 111, VFP-9 Exhibit 112, and VFP10 Exhibit 113. Next panel or witness?

MR. NICKSON: The next panel is the company's Working Performance Metric Panel consisting of Evan M. Crahen, Kevin D. House, and Perry Figliadi. The Working Performance Metric Panel prepared testimony entitled The Direct Testimony of The Working Performance Metric Panel which consists of five pages of questions and answers. I ask that the direct testimony of The Working

Performance Metric Panel be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. So that testimony should appear now Working Performance Metric Panel Direct in the company Direct Testimony folder. Mr. House is also appearing as an individual witness this afternoon. Is that correct?

MR. NICKSON: That is correct.

A.L.J. LECAKES: And he will be sworn in separately from the affidavit then. The affidavit will mark as Exhibit 113 -- I'm sorry 114. Yeah.

DIRECT TESTIMONY OF WORKING PERFORMANCE METRIC PANEL

Q. Please state the names of the members of the Working Performance Metric Panel ("Panel").

A. We are Evan M. Crahen, Kevin D. House and Perry Figliotti.

Q. Mr. Crahen, please state your business address.

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

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

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

Q. Have you provided your educational and professional experience elsewhere in this proceeding?

A. Yes, I have provided this information in the Direct Testimony of Evan M. Crahen in this proceeding.

Q. Mr. House, please state your business address.

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

1 Q. By whom are you employed and in what capacity?
2 A. I am employed by Distribution as an Assistant Vice
3 President with responsibility in the Engineering
4 Services Department.
5 Q. Have you provided your educational and professional
6 experience elsewhere in this proceeding?
7 A. Yes, I have provided this information in the Direct
8 Testimony of Kevin D. House in this proceeding.
9 Q. Mr. Figliotti, please state your business address.
10 A. My business address is 6363 Main Street,
11 Williamsville, New York 14221.
12 Q. By whom are you employed and in what capacity?
13 A. I am employed by Distribution as a Senior Manager in
14 Distribution's Consumer Business Division in the
15 Quality Assurance area.
16 Q. Have you provided your educational and professional
17 experience elsewhere in this proceeding?
18 A. Yes, I have provided this information in the Direct
19 Testimony of Customer Service Panel in this
20 proceeding.
21 Q. What is the purpose of the Panel's direct testimony?
22 A. The purpose of this Panel's direct testimony is to

provide information in response to the New York State Public Service Commission's ("Commission") Order Releasing Report and Providing Guidance on Response issued on April 20, 2016 in Cases 13-M-0314 and 15-M-0566 ("Order").

Q. What does the Order require the Company to provide in this proceeding?

A. The Order directs utilities, including Distribution, to submit "[t]estimony regarding achievement of service goals" (both gas safety and customer service metrics) as part of their next rate case, including the following metrics: 1) Annual Transmission, Gathering and Distribution reports; 2) Reporting of accidents; 3) Reporting of interruptions; 4) Emergency response times; 5) Notice of Interruptions; 6) Gas Safety Performance Measures (pipe replacement, leak backlog, damage prevention, and emergency response); 7) Appointments made/kept; 8) Adjusted bills; 9) Telephone Answer Response; 10) Non-Emergency Service Response Time; 11) Estimated Readings; and 12) Customer Satisfaction.

Q. Does Distribution have service goals related to its Gas Safety and Customer Service Performance Metrics?

A. Yes. Those goals were established through an agreement of the parties in Case 13-G-0136 and were presented to the Commission in a Joint Proposal ("JP") that was approved by the Commission. Under the JP, the Company is penalized if it fails to meet certain gas safety and customer service goals. The Company has always met all required service goals related to Gas Safety Metrics and Customer Service Performance Metrics and has never been penalized for failing to meet any metric.

Q. Does the Company submit reports to New York State Department of Public Service Staff ("Staff") and/or the Commission regarding the results of its Gas Safety and Customer Service Performance Metrics?

A. Yes. With respect to its Customer Service Performance Metrics, Distribution submits an annual report to the Commission and Staff as well as quarterly reports detailing the Company's results. The Company also submits quarterly reports to Staff regarding its Gas Safety Metrics performance

1 results, including emergency response, leak
2 management and damage prevention. Distribution also
3 provides Staff on an annual basis a detailed list of
4 its year-end leak backlog pursuant to the JP in Case
5 13-G-0136.
6 Q. Does the Company also report to the Commission on
7 its leak prone pipe replacements?
8 A. Yes. Pursuant to the JP in Case 13-G-0136, the
9 Company provides Staff a semi-annual leak prone pipe
10 replacement report. The report contains data for
11 leak prone mainline replacement projects completed
12 from January 1st through December 31st.
13 Q. Does this conclude your Panel testimony?
14 A. Yes, at this time.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

National Fuel Gas Distribution Corp.

Case 16-G-0257

August 2016

Prepared Testimony of:

Peter Lavery
Utility Analyst Trainee II
Office of Accounting, Audits and Finance

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

Q. Please state your name, employer, and business address.

A. My name is Peter Lavery. I am employed by the New York State Public Service Department (Department) at Three Empire State Plaza, Albany, New York 12223.

Q. Mr. Lavery, what is your position at the Department?

A. I am employed as a Utility Analyst Trainee II in the Management and Operations Audit Unit of the Office of Accounting, Audits and Finance.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science in Business Administration from the State University of New York at Albany. I have been employed by the Department since July 2015. Prior to joining the Department, I managed a portfolio of New York State-assisted housing contracts at CGI Federal, on behalf of the United States Department of Housing and Urban Development. I performed detailed reconciliations of monthly payments to property owners, and analyzed budget

requisitions for property rental adjustments and contract renewals.

Q. What are your duties at the Department?

A. I am responsible for the oversight of management and operations audits, as well as the implementation of the resulting recommendations.

Q. Have you supervised management and operations audits of New York State utilities?

A. Yes. I have served as an Assistant Project Manager for various ongoing management and operations audits of utility companies. Specifically, I am the Assistant Project Manager for the following cases: 1) Case 13-M-0449, a Focused Operations Audit of the Internal Staffing Levels and the Use of Contractors for Selected Core Utility Functions at Major New York Energy Utilities; and 2) Case 16-M-0001, a Comprehensive Management and Operations Audit of Central Hudson Gas & Electric Corporation. These audits are ongoing. In addition, I manage the implementation of audit recommendations as Implementation Manager for the following cases: 1) Case 10-M-0551, the Comprehensive Management and Operations Audit of Iberdrola, S.A.,

Iberdrola, USA, New York State Electric and Gas, and Rochester Gas and Electric; and 2) Case 11-G-0580, the Comprehensive Management and Operations Audit of National Fuel Gas Distribution Corporation, Inc. (Distribution, or the Company). In this role, I am responsible for ensuring that the Company submits timely implementation updates, reviewing the completion of audit recommendation implementation, and reporting implementation status to Staff and the Commission.

Q. Have you previously testified before the Public Service Commission?

A. Yes, I last testified in the rate proceeding of the Consolidated Edison Company of New York, Inc., Cases 16-E-0060 and 16-G-0061.

Q. Are you sponsoring any Exhibits?

A. Yes, I am sponsoring one exhibit, Exhibit____(PL-1).

Q. In your testimony, will you refer to any information provided by Distribution during the discovery phase of this proceeding?

A. Yes. I will refer to, and have relied upon, responses to Information Requests (IRs) provided

by Distribution. These responses are contained in Exhibit____(PL-1).

Q. What is the purpose of your testimony?

A. Public Service Law, Section 66(19)(c), requires that, “upon the application of a gas or electric corporation for a major change in rates…the Commission shall review that corporation’s compliance with the directions and recommendations made previously by the Commission, as a result of the most recently completed management and operations audit.” Accordingly, my testimony will address Distribution’s overall compliance with the June 27, 2014 “Order Approving an Implementation Plan with Modifications” in Case 11-G-0580 related to the comprehensive management and operations audit of Distribution (management audit), performed by Schumaker & Company (Schumaker, or the consultant).

Q. When was the management audit completed by Schumaker?

A. Schumaker’s “National Fuel Gas Distribution Corporation Final Report” (the Report) was issued by the Commission on August 19, 2013, and

contained 150 findings resulting in 76 recommendations for improvement at Distribution. Each recommendation was accompanied by a Customer Benefit Analysis (CBA) detailing the anticipated costs and benefits associated with implementing the recommendations, as well as the potential risks of not implementing the recommendation. Schumaker's CBAs were developed using information provided by the Company, and included qualitative and quantitative cost and benefit estimates, as appropriate. Distribution witness Mr. Evan Crahen, on pages three through seven of his testimony, provides additional information related to the audit's background, and findings, as well as context of the ensuing implementation process.

Q. What are the Company's responsibilities regarding the outcome of a management audit report?

A. When the Commission issues a management and operations audit report, utilities are required by Public Service Law §66(19) to submit an implementation plan for audit recommendations to the Commission within 30 days. The Commission

may then approve, modify, or reject the submitted implementation plan. Upon the Commission's approval or approval with modification, the implementation plan becomes enforceable. A staff team of subject matter experts is responsible for monitoring the utility's implementation of the audit recommendations. As utilities implement the recommendations, they submit evidence of successful implementation to Staff for review and approval. Accordingly, audit recommendations generally fall into one of four categories of completion status: Not Yet Commenced, In Progress, Pending Review (reported as complete by the utility but under review by Staff), and Completed.

Q. Where in the audit process is Distribution?

A. The Company filed its initial implementation plan for Case 11-G-0580 with the Secretary for the Department on September 18, 2013. Certain changes were made to the initial implementation plan as a result of subsequent discussions with Staff and decisions within Distribution. The Company filed two revisions to its initial

implementation with the Secretary for the Department, on January 17, 2014 and April 25, 2014. The ensuing Commission “Order Approving an Implementation Plan with Modifications” (Order) was issued on June 27, 2014, and directed Distribution to implement the recommendations resulting from the audit consistent with the plan as modified by the Commission. Hereafter, I will refer to the revised implementation plan dated April 25, 2014, and approved with modification by the Commission on June 27, 2014, as the Approved Implementation Plan.

Q. What is the status of Distribution’s compliance with the aforementioned Commission Order in Case 11-G-0580?

A. Distribution has filed timely written implementation updates and has met with Staff between written updates in accordance with the Order. The Company submitted its latest implementation update filing on June 24, 2016. In its update filing, the Company reports that 56 recommendations have been implemented by Distribution and accepted as completed by Staff; 1 recommendation has been implemented by

Distribution and is pending Staff review; the implementation of 15 recommendations are in progress; and the implementation of four recommendations have not yet commenced.

Q. Has Distribution reflected any costs resulting from the implementation of recommendations from the Report in the historic test year, the twelve month period ending December 31, 2015?

A. Yes. On Page 1 of the Company's response to information request DPS-49, which is contained in Exhibit____(PL-1), the Company reports that it has included costs to implement four audit recommendations associated with the Vision 2017 Project #1 (to implement a new timekeeping system) in its revenue requirement. Specifically, the audit recommendations associated with Vision 2017 Project #1 are serial recommendation numbers 13, 14, 15, and 34. The Company reports the implementation costs of these recommendations reflected in historic test year total approximately $1.25 million in Capital, and $72,000 in operations and maintenance (O&M), collectively.

Q. Are there benefits reflected in the historic test year resulting from the implementation of Report recommendations?

A. Yes. On page 2 of the Company's response to DPS-49, contained in Exhibit____(PL-1), the Company reports $49,125 in O&M savings reflected in the historic test year, related to serial recommendation numbers 22, 25, and 64, collectively.

Q. Has Distribution reflected any costs or benefits resulting from implementation in the rate year, the twelve month period ending March 31, 2018?

A. No. On page 2 of the Company's response to DPS-49, contained in Exhibit____(PL-1), the Company reports that no new recommendations with implementation costs or savings are expected to be implemented during the rate year.

Q. Do you have any adjustments to the Company's filing?

A. Yes. Referring to the direct testimony of Ruth M. Friedrich-Alf, Public Service Law requires audits of the major electric and gas utilities at least once every five years, and gives the Commission authority to select a consulting firm

and directs the utility to pay the costs of the audit.

Q. Is the Company anticipating a comprehensive management audit during the rate year?

A. Yes.

Q. Did the Company include expenses for a management audit in its rate year forecast?

A. Yes. The Company included $837,979 in its rate year forecast. This amount represents the “not-to-exceed” cost of the comprehensive management audit of Distribution conducted by Schumaker, as directed by the Commission in 2012.

Q. Are you making any adjustments to the Company’s rate year forecast for its management audit expense?

A. Yes. The Department’s Management Audit Unit does not anticipate that a management audit will be conducted of Distribution during the rate year, and as such, the associated costs should be removed. The removal of the forecasted management audit expense reduces projected rate year O&M expense by approximately $838,000.

Q. Is Distribution the subject of any other recent management and operations audits?

A. Yes. At this time, Distribution, along with other major gas and electric utilities in New York, is the subject of two multi-utility operational audits.

The first is Case 13-M-0314, the Review of the Accuracy and Effectiveness of Certain Reliability and Customer Service Systems at all Gas and Combination Gas and Electric Utilities in New York State that Provide Statistics to the Commission on the Services They Provide Customers. This audit, conducted by Overland Consulting, examined the accuracy of the programs and processes used at the companies to collect data on reliability, safety, and customer service, and the accuracy of the calculations of this data as reported to the Department and the Commission. The final report from this audit was released by the Commission on April 20, 2016. The Company subsequently filed its audit implementation plan for the recommendations from the audit, on May 19, 2016. The implementation plans filed by Distribution and other utilities are currently under review and will be presented to the Commission for its

consideration in the coming months.

Q. Please describe the other operational audit.

A. The second operational audit is Case 13-M-0449, the Focused Operations Audit of the Internal Staffing Levels and the Use of Contractors for Selected Core Utility Functions at Major New York Energy Utilities. This audit is a focused operations audit of the internal staffing levels and the use of contractors for core utility functions at major New York energy utilities. The audit is being performed by Liberty Consulting Group and is examining the internal staffing of certain core utility functions, as well as the criteria and controls used for the use of external staffing. This audit is nearing completion and the final report is expected to be released later in 2016.

Q. Does this conclude your testimony at this time?

A. Yes.

A.L.J. LECAKES: And were there exhibits attached too?

MR. NICKSON: No, Your Honor. There were no exhibits.

A.L.J. LECAKES: Okay. The next panel or witness or is that it?

MR. NICKSON: That is all the affidavits the company has Your Honor.

A.L.J. LECAKES: Okay. Yeah, let's turn to Staff.

MR. FAVREAU: Good afternoon, Your Honor.

A.L.J. LECAKES: Good afternoon. Your first set of witness affidavits?

MR. FAVREAU: The first witness affidavit is from Peter Lavery which consists of -- it's pre-filed direct testimony which consists of 12 pages of questions and answers and we'd ask that this testimony be introduced into the record as if given orally today.

A.L.J. LECAKES: Granted. Have you got the affidavit please? We will mark the affidavit as Exhibit 115.

*Insert Testimony of Peter Lavery

A.L.J. LECAKES: Can we go off the record for a second?

THE REPORTER: Sure.

A.L.J. LECAKES: On the record. Okay. Before we went off the record, we marked the affidavit as Exhibit 115. At this point the folder on the Staff Testimony disk called Staff -- the file on the Staff Testimony disk Staff Lavery Testimony should be copied into the record. Were there any exhibits attached to Mr. Lavery's testimony?

MR. FAVREAU: There was one exhibit, Your Honor. It was PL1. I'm going to ask that it be marked for identification.

A.L.J. LECAKES: And that would be marked as Exhibit 116. Next witness?

MR. FAVREAU: Next witness would be Daniel S. Gadomski. Mr. Gadomski has prepared pre-filed direct testimony consisting of 14 pages of questions and answers. We would ask that this testimony be incorporated into the record as if given orally today. A.L.J. LECAKES: Granted. That testimony is also one that had a redacted version and a confidential version. Is that correct?

MR. FAVREAU: That's correct, Your Honor.

A.L.J. LECAKES: All right. So in the

public version of the transcript, it should have copied into the record right now the file Staff Gadomski Testimony and in parenthesis redacted. On the confidential version it should have Staff Gadomski Testimony in parenthesis confidential copied into the record now. Mr. Gadomski's affidavit please? And that will be marked as Exhibit 117.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter Of

National Fuel Gas Distribution Corporation

Case 16-G-0257

August 2016

Prepared Testimony (REDACTED) of
Staff Witness:

Daniel S. Gadomski
Utility Analyst Trainee 1
Office of Market and Regulatory
Economics

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

Q. Please state your name, employer and business address.

A. My name is Daniel Gadomski. I am employed by the New York State Department of Public Service (Department). My business address is Three Empire State Plaza, Albany, New York 12223.

Q. What is your position in the Department?

A. I am a Utility Analyst economist in the Office of Market and Regulatory Economics.

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

A. I received a Bachelor of Arts Degree in Economics, from the State University of New York at Albany in 2014. I have worked at the Department since 2014, originally as an Operations Clerk in Central Operations, and more recently as a Utility Analyst in the Office of Market and Regulatory Economics.

Q. Have you previously testified before the New York State Public Service Commission (Commission)?

A. Yes, I testified on management compensation and benefits issues in Suez Water NY, Case 16-W-0130; Brooklyn Union Gas, Case 16-G-0058; and

KeySpan, Case 16-G-0059.

Q. What is the purpose of your testimony?

A. I will discuss the reasonableness of the executive variable compensation request for National Fuel Gas Distribution Corporation (Distribution or the Company), presented by the Company's General Compensation & Benefits Panel.

Q. In your testimony, will you refer to, or otherwise rely upon, any information produced during the discovery phase of this proceeding?

A. Yes. I will refer to, and have relied upon, several responses to Staff Information Requests (IRs). These responses are included in Exhibit__(DSG-1).

Q. Please summarize your conclusions regarding the Company's executive variable incentive compensation program.

A. The Company has not provided the information necessary to make an adequate assessment and determination of the reasonableness of the Company's executive incentive compensation request. Therefore, the Company's request for recovery of executive incentive pay in rates should be rejected.

Q. Did you review incentive compensation for Distribution's non-executive management employees?

A. No. The Company's response to response to DPS-48, question 4 indicates that "Management (non-executive) employees are not eligible for any separate incentive based compensation programs and therefore there are no performance targets to track in that respect."

BACKGROUND

Q. Please summarize the Commission's requirements regarding what Distribution must demonstrate in order to recover the costs of variable compensation in rates.

A. In Case 10-E-0362, on page 38 of its Order Establishing Rates for Electric Service, for Orange and Rockland Utilities, Inc., issued June 17, 2011, the Commission states that the utilities must demonstrate, with a compensation study of similarly situated companies being the preferred methodology, that its total compensation, inclusive of incentive pay, is reasonable relative to its peers. However, such a plan cannot have performance targets that are

detrimental to Commission interests. Alternatively, the Company could clearly demonstrate that its compensation program provides quantifiable or demonstrable benefits to its ratepayers in a financial sense or in terms of reliability, environmental impact, or customer service.

COMPENSATION BENCHMARKING ANALYSIS

Q. Did the Company provide a benchmarking study to support the reasonableness of its executive incentive compensation package?

A. Pre-filed IR UFR-27 requested that Distribution provide a compensation study measuring the utility's overall compensation levels relative to similarly situated companies. The Company responded stating that a study was compiled and submitted, as recommended during the Company's most recent management audit. Subsequently, DPS-48 requested a copy of the study which the Company then provided in its response.

Q. Please describe the benchmarking study provided in response to DPS-48.

A. The Company contracted with the human resources consultant firm Hay Group to conduct a

compensation study, as recommended during the most recent management audit. The Company provided the January 2014 Hay Group study, which summarized the market competitiveness of Distribution's overall executive and top management compensation package.

Q. What were the results of the Company's executive compensation benchmarking study?

A. The Company concluded that its target total remuneration, which is the sum of base pay, lump sum pay, long-term incentive pay, and total benefits, for executive employees is exactly at the median of the general industry comparator group.

Q. By what standard should a company's benefits and compensation package be viewed as market competitive?

A. According to the World at Work Handbook of Compensation, Benefits & Total Rewards: A Comprehensive Guide for HR Professionals, as a rule of thumb, a company's compensation and benefits should be within plus or minus 10% of the market.

Q. Do the results of the Company's benchmarking

study indicate that the Company's executive compensation program is market competitive?

A. As I will explain, without additional detail on actual versus targeted incentive pay amounts and additional information regarding the composition of the peer group, the reasonableness of Distribution's market competitiveness demonstration cannot be determined.

TARGETED VERSUS ACTUAL INCENTIVE PAY

Q. Did you ask the company to provide more information regarding how much incentive pay is targeted as compared to how much incentive pay is actually distributed to employees?

A. Yes. IR DPS-162 asked the Company to provide the target and actual compensation amounts used for each Company and comparator position in the Company's compensation benchmarking study. In its response, the Company stated that "The Hay Group's specific comparator data for actual cash compensation amount was not revealed to the Company." The Company only provided actual compensation figures for its own executives' base salary and lump sum incentive pay.

Q. Are actual compensation amounts necessary to

determine a company's market competitiveness?

A. Yes. Target compensation amounts can differ significantly from the actual compensation amounts that are paid. Companies have varying incentive payment structures and ways to utilize their structures to align with the particular goals on which they choose to focus. Also, companies may place more weight on incentive compensation to supplement a lower than average base salary. Different companies place certain emphasis on different goals, as well as assigning varying degrees of difficulty and compensation associated with achieving particular targets. Thus, it would be reasonable to benchmark both targeted and actual incentive compensation. From the information provided in response to DPS-162, Attachment 1, I calculated that **[Begin Confidential] [End Confidential]**

PEER GROUP USED FOR BENCHMARKING ANALYSIS

Q. What peer group was utilized to analyze the competitiveness and reasonableness the Company's compensation program?

A. Hay Group compared the Company's total remuneration package to a general industry

comparator group composed of 486 organizations. The general industry peer group, inclusive of energy industry organizations, comprised companies of various size which compete in diverse industries.

Q. Please describe your review of the Company's peer group selection.

A. Staff IR DPS-48 (Exhibit___(DSG-1)) requested a listing of where the Company's new hires were previously employed.

Q. Why is this important?

A. Because a primary goal of a good compensation program is to attract and retain employees while not paying too much. Thus, it is necessary to evaluate the compensation levels of those companies in competition with the utility in the labor market. The Company's response to DPS-48 (Exhibit ___(DSG-1)) supplied a list of previous employers for management employees. These are the firms from which the Company competed away employees.

Q. Based upon your review, is the Company's peer group reasonable?

A. The Company's response to DPS-48, Question 3,

indicated that it competes for employees from various general and energy industry companies. As noted above, the peer group relied upon in the Hay Group study was drawn from a pool of similar organizations from which Distribution competes for talent. However, without the underlying data identifying the subset of companies used for each position matched in the compensation study, it is not possible to determine if the subset of peer group positions matched to each of Distribution's positions were reasonably comparable. For example, an auditing executive would have a skill set that could be applied in both a general industry and energy industry setting. For this position match, it would be reasonable for the benchmarking study to have used positions from both the general industry and utility industry peer groups. In contrast, a benchmarking of a utility engineering executive position should more reasonably focus on position matches from the utility industry peer group.

Q. Did Distribution identify the industry from which the peer group matches were derived for

each of its benchmark positions?

A. IR DPS-216 asked the Company to provide the percentage of peer group employees utilized from general industry versus utility industry companies, for each position matched. The Company was unable to provide the information stating that “The specific comparator data used by the Hay Group for each position matched was not revealed to the Company.” Staff IR DPS-162 also asked the Company to provide the underlying data used in developing its compensation comparisons. The Company’s response states, “The Hay Group’s specific comparator data was not revealed to the Company.” Thus, the Company has not provided the additional information necessary to make an adequate assessment and that its total compensation package is comparable to its peer companies.

Q. Is the Company required to provide the underlying data to support the reasonableness of its total compensation study?

A. Yes. In Case 11-E-0408, on page 20 of its Order Adopting Terms of Joint Proposal, With Modification, and Establishing Electric Rate

Plan, for Orange and Rockland Utilities, Inc., issued June 15, 2012, the Commission stated "the parties should have access to all of the data, methodology, and models underlying the studies supporting the reasonableness of total compensation, and that this information should be available at the time of the initial rate filing."

PERFORMANCE TARGETS FOR INCENTIVE PAY

Q. Please describe your review of the Company's employee performance targets used in its incentive pay program.

A. IR DPS-48 and DPS-162 (Exhibit___(DSG-1)) also asked the Company to provide their tracking of employee performance against its targeted objectives metrics. The request also asked for the Company's determination of compensation increases, the performance of employees against variable pay targets and the payouts of incentive pay.

Q. Why is this information important?

A. It is necessary to ensure that these targets are in line with Commission objectives. In Case 10-E-0362, Orange & Rockland Utilities, Inc., the

Order Establishing Rates for Electric Service, issued June 17, 2011, requires a demonstration that "should confirm that the incentives will support the provision of safe and adequate service and will have no potential to adversely affect ratepayer interests or to promote results that are inconsistent with Commission policies." Thus, it is necessary to determine if the performance goals/incentives are reasonable, and beneficial to ratepayers.

Q. Has the Company reasonably demonstrated that its target performance goals are in line with Commission objectives related to customer service, the environment, safety and reliability?

A. The performance goals for incentive pay, shown on pages 33 and 34 of the Proxy Statement supplied in DPS-48, Attachment 2, indicates that the great majority of performance targets related to Distribution's executive incentive pay are associated with improving the Company's financial performance. The executive pay incentive plan does not appear to be focused enough toward customer service, environmental

protection, safety or reliability to conclude that the incentive pay plan is reasonably necessary to provide safe and adequate service; or that the cost to ratepayers is at least matched by the benefits they receive.

Q. Has the Company demonstrated that its executive incentive pay plan and associated performance targets are sufficiently “focused, solely or in large part on goals for safety, reliability, environmental protection or customer service” as required by the November 21, 2011 Order in Case 10-E-0362?

A. No.

SUMMARY AND CONCLUSION

Q. In summary, what do you recommend regarding the Company’s executive compensation request?

A. Since the Company has failed to demonstrate the reasonableness of its executive compensation benchmarking study and has also failed to clearly demonstrate that its compensation program and incentive performance targets provide quantifiable or demonstrable benefits to its ratepayers in a financial sense or in terms of reliability, environmental impact, or

customer service, I recommend the disallowance of the total $2.638 million executive incentive compensation amount requested by Distribution in this proceeding.

Q. What impact does your recommendation have on the Company’s revenue requirement?

A. The adjustment amounts to a decrease in $1.585 million, as reflected in Staff Witness Haslinger’s Testimony.

Q. Does this conclude your testimony at this time?

A. Yes.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

National Fuel Gas Distribution Corp.

Case 16-G-0257

August 2016

Prepared Testimony of:

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Public Utilities Auditor 3
Office of Accounting, Audits and Finance

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

Q. Please state your name and business address?

A. Robert Haslinger. My business address is Three Empire State Plaza, Albany, New York 12223.

Q. Mr. Haslinger, by whom are you employed and in what capacity?

A. I am employed by the Department of Public Service in the Office of Accounting, Audits and Finance as a Public Utilities Auditor 3.

Q. What is your educational background and experience?

A. I graduated from Niagara University in May 1980 with the degree of Bachelor of Business Administration. I majored in Accounting. Since 1980, I have been employed by the Department of Public Service as a Public Utilities Auditor. My work involves examinations in electric, gas and telephone proceedings, compliance filing audits, financings, and other general accounting matters.

Q. Have you previously testified before the New York State Public Service Commission?

A. Yes. I have testified in numerous proceedings before this Commission, including Iberdrola, S.A.'s acquisition of Energy East (Case 07-M-

1 0906), New York State Electric and Gas's (NYSEG)
2 electric rate case (Case 05-E-1222), as well as
3 all of Rochester Gas & Electric Corporation's
4 (RG&E) rate cases over the last decade,
5 including RG&E's 2003 electric and gas rate case
6 (Cases 03-E-0765 and 03-G-0766). I testified in
7 NYSEG's and RG&E most recent cases (Cases 09-E-
8 0715, 09-G-0716, 09-G-0717 and 09-G-0718) and
9 (15-E-0283, 15-G-0284, 15-E-0285 and 15-G-0286)
10 Q. Please briefly describe your responsibilities
11 with the Department.
12 A. I have general responsibility for accounting and
13 ratemaking matters related to companies
14 regulated by the New York State Public Service
15 Commission. My direct responsibilities include
16 examination of accounts, records, documentation,
17 policies and procedures of regulated utilities
18 and the development of various analyses related
19 to revenue requirements proposed by Staff from
20 that information.
21 Q. What is the purpose of your testimony in this
22 proceeding?
23 A. I am responsible for examining certain areas of
24 National Fuel Gas Distribution Corp.

1 (Distribution or the Company) rate year (RY)
2 forecasts of revenues, operation and maintenance
3 (O&M) expenses and operating taxes.
4 Q. As a result of your examination of
5 Distribution's rate year forecasts, are you
6 proposing any adjustments?
7 A. Yes. The areas of adjustment I am proposing are
8 labor, productivity, billing, contractors and
9 outside services, information systems, Barcelona
10 post-install expense and payroll taxes.
11 Q. Have you prepared exhibits for this proceeding?
12 A. Yes. Exhibit __(RPH-1), Exhibit __(RPH-2) and
13 Exhibit __(RPH-3).
14 Q. Please briefly describe your exhibits.
15 A. Exhibit __ (RPH-1) is a presentation I created
16 to summarize the Company's labor forecast for
17 the rate year. Exhibit __ (RPH-2) is a
18 presentation of Staff's forecast for the rate
19 year. Staff's Exhibit___ (RPH-3) includes the
20 Information Request (IR) responses that I rely
21 upon throughout my testimony. I will refer to
22 these IRs by the number assigned by Staff, e.g.,
23 DPS-169.
24 Q. Would you describe Exhibit___(RPH-4)?

1 A. Exhibit___(RPH-4) is a compilation of the
2 workpapers I used and/or developed to support my
3 proposed adjustments.
4 Labor/Payroll Expense
5 Q. Please explain how the Company developed its
6 forecast of labor expense.
7 A. The Company began with its historic year actual
8 book labor expense of $50.685 million as the
9 starting point and then forecasted it out to the
10 rate year.
11 Q. How did the Company forecast labor from the
12 historic year to the rate year?
13 A. As described by Company witness Barber's
14 testimony at pages 5 through 8, and shown in the
15 Company's Exhibit_ (JRB-2) Schedule 1, Sheet 4,
16 the Company began by annualizing the historic
17 year end weekly (union) payroll at December 26,
18 2015. It then added in actual calendar year
19 2015 summer and other payroll, temporary, part-
20 time and overtime pay. Next, the Company
21 annualized the January 15, 2016 supervisory
22 payroll category to include the most recent
23 known supervisory base salary increase. The
24 Company then made further adjustments to add in

1 executive pay and labor borrowed from other
2 jurisdictions. The amount of labor borrowed
3 from other jurisdictions represents labor
4 charged by its affiliated companies and booked
5 to Distribution, such as for the National Fuel
6 Gas Pennsylvania Distribution Company. Finally,
7 the Company combined all of the individually
8 forecast labor subcategories to produce its
9 total gross normalized historic year labor of
10 $78.207 million.
11 Q. Please explain how the Company forecast its rate
12 year labor expense.
13 A. Distribution took the normalized historic year
14 labor and increased it for both the latest known
15 wage increases and forecasted wage increases for
16 years 2016 - 2018. The forecasted wage
17 increases vary between 1.5% and 2% for union
18 employees. The Company employed a 3% increase
19 each year to forecast non-union employee's
20 salaries. The Company then utilized a historic
21 year O&M expense percentage of 66.33%, to
22 determine the amount of gross normalized labor
23 to be charged to expense based on the calendar
24 year 2015 percentage. The remainder of the

1 gross payroll amount would be charged to capital
2 (construction) or other non-expense categories.
3 Q. Do you agree with the Company's rate year labor
4 forecast?
5 A. No. The Company's forecast contains a
6 significant error.
7 Q. Please explain.
8 A. While the Company's forecast properly accounts
9 for the labor it borrows from other
10 jurisdictions, it fails to account for its own
11 labor that is charged out to other
12 jurisdictions. These charges to other
13 affiliated companies reduce the amount of labor
14 incurred by New York Distribution, and the
15 amount of labor that is shown on its books.
16 This error had the effect of significantly
17 overstating the Company's rate year forecast of
18 labor expense.
19 Q. What does labor charged to other jurisdictions
20 represent?
21 A. In response to DPS-169, Distribution explained
22 "The Common Cost Allocation is an allocation of
23 administrative and general costs for certain
24 "common" departments that affect the operations

1 of subsidiary companies of National Fuel Gas
2 Company. The Administrative and General costs
3 are comprised of salaries, office supplies,
4 rents, utilities and other office expenses of a
5 general nature. The common departments are
6 identified as departments within the New York
7 jurisdiction of National Fuel Gas Distribution
8 Corporation that perform work that benefits or
9 affects multiple subsidiaries within National
10 Fuel Gas Company. These subsidiaries would
11 include Distribution Corporation, Supply
12 Corporation, Seneca Resources Corporation,
13 National Fuel Resources, Empire Pipeline, Inc.
14 and NFG Midstream, Inc."
15 Q. How are costs allocated to these subsidiary
16 companies?
17 A. The allocations are generally based on factors
18 such as net plant, total throughput and total
19 operating and maintenance expenses, less some
20 other costs such as purchased gas costs.
21 Q. Did the Company correctly account for the labor
22 charged to other jurisdictions in its historic
23 year per book amount?
24 A. Yes. Per the Company's Exhibit __ (RMFA-2)

1 Schedule 1, Workpaper Page 12, it shows the per
2 book labor expense of $53.742 million reduced by
3 ($5.697 million) for the amount of labor charged
4 to other jurisdictions and increased by $2.725
5 million for the amount of labor borrowed and
6 charged back to New York Distribution from other
7 jurisdictions. The net amount of both labor
8 loaned and labor borrowed is a reduction in the
9 per book amount of ($2.972) million. This
10 amount can be seen in the Company's Exhibit __
11 (RMFA-2), Schedu1e 1, Workpaper Page 1,(Loaned
12 and Borrowed Labor) showing the reclassification
13 of labor as well as various other non-labor cost
14 elements.
15 Q. Please explain how the Company's failure to
16 account for labor loaned and charged to other
17 jurisdictions affects its forecasted amounts of
18 normalized and rate year labor.
19 A. Staff has provided Exhibit __ (RPH-1) which
20 shows a historical presentation, as well as the
21 Company's forecast of the rate year gross labor,
22 expense labor, labor charged to, and labor
23 charged from other jurisdictions. The exhibit
24 also contains historical and forecast of the

1 Company's headcount. As can be seen in Staff's
2 Exhibit___(RPH-1), the Company's forecast of
3 gross labor (total labor before charges to
4 expense and non-expense) shows a historic test
5 year gross amount of $79.849 million, a Company
6 normalized amount of $78.207 million and a
7 Company forecasted rate year amount of $81.253
8 million. These amounts show an increase of
9 approximately 1.75% in gross labor from the
10 historic year to the rate year. The Company's
11 expensed amount of labor shows a historic test
12 year amount of $50.685 million, a normalized
13 amount of $55.377 million and a rate year amount
14 of $57.561 million. The labor amount being
15 charged to expense is projected to rise by over
16 13.5% from the historic year to the rate year.
17 The error is evident when observing the large
18 jump in labor expense from the historic test
19 year $50.685 million (which recognizes the labor
20 charges to other jurisdictions), when compared
21 to the $55.377 million normalized labor amount,
22 which ignores the $5.697 million amount of New
23 York labor charged out of the New York
24 Distribution Company, as well as a small charge

1 to benefits. Also of note, the Company's
2 forecast of gross labor actually decreases from
3 the historic year to the normalized amount,
4 while expensed labor rises sharply by 9.26%.
5 Q. What effect does this error cause in the amount
6 of gross labor charged to expense?
7 A. As can be seen in my Exhibit___ (RPH-1), the
8 percentage of gross labor charged to expense,
9 rises to over 67% in the Company's projected
10 normalized and rate year expensed labor amounts.
11 This contrasts sharply from the actual calendar
12 years 2011 through 2015 historic years' labor
13 expense amounts of approximately 60%.
14 Q. Could the large change in expensed labor be due
15 to a forecasted change in the percentage of
16 labor charged to expense or increased head
17 count?
18 A. No. The Company held its labor expense
19 percentage constant throughout its forecast of
20 normalized and rate year labor. The Company's
21 response to DPS-150 (Exhibit __(RPH-3)) shows
22 the actual headcount changed very little from
23 the beginning of the historic year to the end of
24 the historic year, and the Company did not

1 forecast any increase in headcount from the end
2 of the historic test year to the rate year. The
3 Company's Barcelona Project Customer Information
4 System installation forecasted additional
5 employees, but the related incremental labor
6 charges are accounted for separately from the
7 labor forecast in its own distinct cost element
8 labelled as Barcelona post install expenses. In
9 developing my rate year labor forecast, I have
10 also removed the Barcelona related employees
11 from headcount, as they are accounted for
12 separately in the Barcelona project cost
13 element. These Barcelona project related
14 employees were hired in calendar years 2014
15 through 2016 and their labor charged to capital,
16 as detailed in Distribution's response to DPS-84
17 (Exhibit __(RPH-3)).
18 Q. What adjustment is necessary to correct for the
19 identified error?
20 A. The Company's rate year labor expense forecast
21 should be reduced by $5.888 million to properly
22 account for labor loaned to other jurisdictions.
23 Q. Does Staff's forecast properly include the
24 amount of labor loaned to other jurisdictions?

A. Yes. As shown in Staff's Exhibit___(RPH-2), Staff's forecast includes the $5.8 million amount for labor the Company should have included in its rate year forecast for labor loaned to other jurisdictions. Staff has increased the amount of labor loaned to other jurisdictions from the normalized period to the rate year by the rate of increase used by the Company for its overall labor forecast. This increase is derived from the Company's Exhibit__ (JRB-2), Schedule 1, Sheet 1, showing a 3.94% increase from the normalized period to the rate year ($55,377(000) to $57,561(000).Staff's Exhibit___ (RPH-2) illustrates that Staff's adjustment to include the proper amount of labor to other jurisdictions brings the allocated labor expense percentage more in line with past actual historical values.

Q. Have you reviewed the latest known level of labor expense?

A. Yes. In response to DPS-152, (Exhibit __(RPH-3)) the Company provided the 12 months ended June 30, 2016 labor expense.

Q. What does the latest labor data show?

1 A. It shows $50.578 million of net labor expense
2 charges to the New York Distribution, slightly
3 less than the historic year amount of $50.685
4 million. This is in sharp contrast to the
5 Company's forecasted normalized labor expense of
6 $55.377 million, which is based on historic year
7 amounts without the labor charged to other
8 jurisdictions. This provides additional support
9 that the Company's forecast contains a
10 significant error.
11 Q. Do you agree with the Company's use of a 66.33%
12 expensed labor percentage?
13 A. No. The Company's labor percentage of 66.33% is
14 based upon its use of the amount of labor
15 expense before any allocation of labor to other
16 jurisdictions. This labor expense percentage is
17 used by the Company and applied to payroll
18 taxes, and with a slight adjustment is also used
19 to determine the amount to be charged to expense
20 for employee fringe benefits.
21 Q. Has the Company indicated that its expense
22 percentage calculation of the 66.33% may be
23 wrong?
24 A. Yes, in fact the Company seems to now realize

there is an error in its rate year labor expense forecast. In response to DPS-4 – Follow-Up, (Exhibit __(RPH-3)) the Company stated that it had come up with " A theoretical O&M% that would be relatively accurate to the actual O&M % for that particular calendar year." The Company produced a theoretical O&M percentage of 62.57%. In response to DPS-188, (Exhibit __(RPH-3)) Distribution stated "Labor to Other Jurisdictions should have been included in the calculation of the O&M percent, but was excluded in error."

Q. Do you agree with the Company's revised O&M labor percentage?

A. No.

Q. What is the correct percentage of labor that should be charged to expense?

A. Staff's Exhibit___(RPH-2) shows the New York actual labor expense per the Company's books after it charges the labor to other jurisdictions. For the historic year, New York Distribution had a gross payroll of $79.849 million and of that gross payroll, $47.960 million was charged to expense, after allocation

of labor to other jurisdictions (affiliated companies). The exhibit shows that 60.06% of its own New York labor was charged to New York O&M expense. This 60.06% should be used to determine the percentage of New York payroll ultimately charged to O&M expense.

Q. Why don't you include labor from other jurisdictions when computing the New York Distribution O&M expense percentage?

A. This particular labor being charged to expense is not from New York Distribution, but from other jurisdictions (other affiliated companies) and should not be included when calculating the New York O&M percentage.

Q. What is the Staff adjustment to the Company's rate year labor forecast?

A. As shown in Exhibit __ (RPH-2), Staff's adjustment reduces the Company's rate year forecast by $5.888 million.

<u>Productivity</u>

Q. Did the Company include a computation of productivity in its rate filing?

A. No. The Company did not include a productivity adjustment in its rate filing.

Q. Did the Company explain why it did not include a productivity adjustment in testimony or exhibits?

A. No. The Company did not explain nor support the reasoning for excluding a calculation of productivity in the rate filing.

Q. Is there any testimony describing any productivity occurring in this rate case presentation?

A. Yes. In the direct testimony of the Company's General Compensation & Benefits (GCP) Panel, at page 15, the Panel discusses the reasons for authorizing wage increases in excess of inflation. The Panel testimony states: "Given the above discussed gains in productivity achieved by our management employees, an increase above the expected inflation rate is certainly warranted."

Q. What is the Commission's general policy on productivity?

A. The Commission has a long-standing policy of imputing a productivity adjustment, which is intended to capture unidentified and/or unquantifiable productivity gains, efficiencies

and cost savings that could be realized in the rate year. The standard productivity adjustment is not intended to capture savings associated with a particular program. This adjustment is typically calculated at one percent of total labor expense, employee benefits and payroll taxes. The Commission's policy of the one percent productivity adjustment has been supported by past rate case opinions, specifically, Case 29541, New York State Electric & Gas Corporation, Opinion 88-2, Opinion and Order Determining Revenue Requirement and Refunding Excess Earnings, Issued and Effective January 20, 1988 and Case 95-G-1034, Proceeding on the Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service, Opinion No. 96-28, Opinion and Order Concerning Revenue Requirement and Rate Design, Issued and Effective 3, 1996.

Q. Did Staff compute a productivity adjustment?

A. Yes. Staff has included the traditional one percent Commission productivity based on the Staff adjusted amounts of Labor, Employee

Benefits and Payroll Taxes. The Staff Policy Panel is also recommending an addition 1% productivity adjustment in their testimony. This is shown as a $1,538,000 reduction in O&M Expense for the rate year.

Executive Incentive Pay

Q. Did the Company include executive incentive compensation in its rate year forecast of labor expense?

A. Yes. As indicated in its response to DPS-104, the Company included $2.638 million of officers and executives bonuses and long term incentive compensation.

Q. Is Staff recommending an adjustment to the amount associated with executive incentive compensation from the rate year labor forecast?

A. Yes. Staff witness Gadomski is recommending disallowance of the entire $2.638 million from the rate year labor forecast. Applying Staff's 60.06% O&M expense allocation results in a labor expense adjustment of $1.585 million and is reflected in Staff's summary of adjustments and revenue requirement calculation.

Billing

Q. What does the billing cost element represent?

A. The costs associated with billing are the expenses to render a bill to a customer.

Q. How does the Company account for its customer billing?

A. The billing costs initially get charged to the customer billing and postage clearing account, the function of which is to accumulate the costs associated with customer billing. The accumulated costs are then allocated and charged out to the appropriate New York or Pennsylvania Distribution Company jurisdictions based on the number of customers.

Q. What makes up the majority of the costs of customer billing?

A. Approximately 90% of customer billing and postage clearing account is associated with postage.

Q. Has the cost of postage changed since the historic test year (calendar year 2015)?

A. Yes. The United States Postal Service decreased its rates on April 10, 2016 from $0.485 to $0.465 for the first class metered mail

category.

Q. Did the Company reflect the postage rate decrease in its rate year forecast of customer billing?

A. No. The Company's response to Staff's Information Request DPS-59(Exhibit __(RPH-3)) states "The Company did not forecast individual changes but applied the group approach inflation adjustment to all budget items in all of the clearing account analyses with the exception of Labor and associated benefit loadings."

Q. Should the change in postage rates be reflected in the rate year billing expense cost element?

A. Yes, it is a known and measurable change in postage costs and as such, should be reflected in the rate year billing expense. Since the Company declined to compute an adjustment for the decreasing postage rate, Staff has computed an adjustment based on the rate change in metered mail. The rate declined from $0.485 to $0.465, a 4.1% decrease.

Q. What is the effect on rate year billing expense?

A. Staff has reduced the billing postage expense by $220,000, to reflect this known and measurable

change.

Barcelona Post Install Expenses

Q. What does the Company's Barcelona post install expenses cost element represent?

A. The Barcelona post install expenses are the costs associated with the Company's new Customer Information System (CIS). The Company has forecast it will incur $3.036 million of additional O&M expenses associated with the implementation of the CIS in the rate year.

Q. What incremental cost components did the Company forecast would make up this $3.036 million?

A. Based upon the Company witness Boyle's testimony on page 52, the following items comprise the projected incremental cost:

Software Maintenance Fees	$1,750,000
Disaster Recovery Services	386,000
IT Support Analysts (10FTEs)	900,000
Total O&M Expense	$ 3,036,000

Q. Did Distribution substantiate these amounts with any supporting testimony, exhibits or workpapers?

A. No, the table in Mr. Boyle's testimony was the sole support for the rate year amount.

Q. How did Staff substantiate the amounts the Company is claiming?

A. Through a series of Staff interrogatories, the Company supplied information regarding the components of the new Barcelona Customer Information System.

Q. Did the information Staff gathered support the Company's forecast?

A. Although the information Staff received generally supported the amounts the Company had shown in its testimony, the amounts were reflective of the total gross projected amounts and not solely the portion that should be allocated to National Fuel Gas New York Distribution.

Q. Should these costs be shared with Distribution's other affiliated companies?

A. Yes. The costs of the new Barcelona Customer Information System should be shared by the affiliated company in Pennsylvania, as this CIS will be utilized by both New York and Pennsylvania for its distribution customers.

Q. How should these cost be assigned to the affiliated Pennsylvania distribution company?

A. Since the Barcelona computer system is a customer information system, its costs should be allocated based on the number of distribution customers each affiliate serves. The Company's response to DPS-153, (Exhibit __(RPH-3)) provided the allocation factors it proposes to use based upon the customer count by state.

Q. What are the allocation factors based on the number customers associated with New York and Pennsylvania Distribution?

A. The factors based on number of customers would allocate 71% to New York Distribution and 29% to Pennsylvania Distribution.

Q. What is Staff's adjustment to properly allocate these Barcelona project costs?

A. The Company's responses to information requests DPS-27, DPS-153 and DPS-175, (Exhibit __(RPH-3)) provide more detailed information regarding the incremental Barcelona costs. Based on the responses to DPS-27 and DPS-175, the Company has revised its projection of incremental costs based on the identification of updated specific actual costs which will have the effect of slightly reducing the annual operating cost for

software maintenance than what was provided in the Company's testimony. In the response to DPS-153, the Company provided the New York allocation for each O&M expense item. The New York Distribution allocation of the Barcelona project related costs, i.e. software maintenance, disaster recovery and IT support analysts) now total $2.520 million based on the Company's latest projections and information. Comparing this amount to the $3.036 million the Company has included in its rate year expense forecast in the initial filing results in a downward adjustment of $.516 million.

Q. Has the Company quantified any savings associated with the installation of the new Barcelona CIS system in the rate year?

A. No. In its response to DPS-212, (Exhibit __(RPH-3)) the Company did not explicitly identify or quantify the benefits of the new CIS system, nor did they quantify any savings associated with the discontinuation of the old legacy system. In fact the Company confirms this by stating, "There are no savings and/or benefits associated with the new CIS reflected

1 in the RYE 3/31/2018 forecast …"
2 Q. Does the Company's witness Boyle address any
3 benefits and efficiency improvements associated
4 with the change over to the new CIS Barcelona
5 project?
6 A. Yes. Witness Boyle on page 8, of his testimony,
7 describes how the old CIS has become quite
8 complex and difficult to maintain, and that this
9 manifests itself in cost prohibitive estimates
10 for changes and the inability to meet business
11 needs in a timely manner. This complexity has
12 increased required testing to ensure that even
13 small changes do not introduce unintended
14 consequences on the larger system.
15 Q. Does the Company's witness Boyle expect benefits
16 associated with the replacement of the old
17 legacy system and the implementation of the new
18 of the Barcelona CIS?
19 A. Yes. On page 9, lines 5-8, of his testimony, he
20 states "The expected benefits of replacing the
21 Company's CIS include increased flexibility in
22 Distribution's ability to be both proactive and
23 reactive to business changes in terms of what
24 the system changes can and cannot be

accomplished in a timely and cost effective manner."

Q. Does Company witness Boyle indicate any improved efficiencies with the transition from the old legacy technology to the new CIS?

A. Yes. On page 10, lines 10-17, of Boyle's testimony, he states "Implementing the new 'uncluttered" system will reduce the risks of introducing unintended negative consequences with system changes. It will reduce the turn-around time for requested business changes – once Distribution's information technology support staff achieves homeostasis with the new system and becomes proficient with the SAP technologies."

Q. Does the Company witness further describe the benefits of the new technology over the old CIS?

A. Yes. The witness states on pages 13-14, "The Company's new CIS will position Distribution for the next generation of service offerings whether initiated by customers, market conditions, State Regulatory Commissions, or Distribution itself. The underlying data model will enable significant flexibility in rate design and the

1 ability of Distribution to analyze customer
2 data. The newer technology enhances
3 Distribution's ability to interact with the
4 multiple channels (web-based applications,
5 mobile applications on cell phones, social media
6 applications, etc.) that customers expect to use
7 in communicating with their local utility
8 company."
9 Q. Does the Company witness refer to improved
10 workflow associated with the switch to the new
11 CIS?
12 A. Yes. The witness explains on pages 14-15, how
13 the change from the old paper based system,
14 which relied on printed paper reports which were
15 then distributed to employees for task
16 assignment, tracked for performance and followed
17 through for resolution. This greatly limited
18 the visibility of work progress by management.
19 Under the new non-paper the witness states
20 "Distributions' new CIS will improve internal
21 workflow providing management the ability to
22 know who has what work, and where they are with
23 that work in near real-time. Work can be
24 shifted electronically if events warrant the

1 movement of the work from one employee to
2 another for whatever reason."
3 Q. Will the new CIS make customer data retrieval
4 simpler and more efficient for non-technical
5 system users than under the old CIS?
6 A. Yes. At pages 15-16, witness Boyle explains how
7 under the old system non-technical users could
8 not interact with the customer data other than
9 reports maintained by the programming staff.
10 The new system will allow key business users to
11 create their own data extracts and queries
12 enabling them to self-serve.
13 Q. Does the Company describe how the new CIS will
14 be more easily maintained than the old CIS?
15 A. Yes. At Boyle testimony pages 16-17, the Company
16 indicates that the old system is difficult to
17 maintain due to the lack of qualified
18 professionals experienced with the old
19 technology. Distribution was forced to compete
20 with other companies for the ever-decreasing
21 workforce of mainframe professions, or hire
22 individuals and train them from the ground up on
23 mainframe technologies. The new CIS will enable
24 the Company to hire entry-level employees that

1 have the academic background to support the new
2 system. This enables the Company to attract a
3 greater pool of technology trained applicants
4 and the new employees will become productive
5 sooner, since they are hired to support similar
6 technologies with recent college knowledge.
7 Q. Does the Company have difficulty in negotiating
8 software maintenance fees for the old mainframe-
9 based system?
10 A. Yes. As witness Boyle stated in his testimony
11 pages 18-19, the Company was obliged to pay
12 higher software fees due the lack of
13 alternatives for its mainframe-based system.
14 The new CIS will give the Company options in
15 regards to software add—ons and the companies
16 offering SAP consulting services due to the much
17 wider and growing base of SAP applications.
18 Q. Please summarize the benefits of the new CIS
19 that Company witness Boyle has identified.
20 A. Company witness Boyle has identified the
21 following benefits associated with the new CIS:
22 improved workflow, greater efficiencies,
23 increased flexibility to business changes,
24 timely data retrieval, improved system

maintenance, more competitive software maintenance fees pricing, increased choices for consulting services and increased productivity of new hires with current technology knowledge.

Q. Considering all the benefits outlined and described by Company witness Boyle, shouldn't there be some realization of efficiency savings?

A. Yes. It is Staff's belief that there will be some realization of savings based on the benefits as described by witness Boyle.

Q. Since the Company did not quantify these benefits associated with the transition to the new CIS, is there a way to quantify and capture savings associated with these benefits?

A. Yes. Staff's Policy Panel has proposed an additional one percent productivity adjustment over the standard one percent, to reflect the unquantified cost savings associated with the installation of the new CIS.

<u>Contractors & Outside Services</u>

Q. What does the cost element Contractors & Outside Services represent?

A. This cost element represents the payments to outside vendors that the Company employs in

order to provide various utility services, such as legal, IT consulting, collection services, landscaping, etc.

Q. How did the Company project the rate year expense for this cost element?

A. The Company added inflation to the historic year actual amount.

Q. Has Staff completed a review and analysis of the historic year costs associated with the contractors and outside services cost element?

A. Yes. Staff reviewed the historic test year (calendar year 2015) and compared the total to past historical year amounts.

Q. What did this comparison reveal?

A. Based on the information provided in the Company responses to information requests DPS-54 and DPS-127, (Exhibit __(RPH-3)) Staff found the historic test year actual to be higher than all the previous calendar years used in the comparison.

Q. Did Staff inquire as to the reason for this increase?

A. The Company provided reasons for the increase in its outside services costs in response to

1 information request DPS-127. As part of the
2 analysis performed, Staff also reviewed the
3 vendor payments for the costs incurred in the
4 historic test year and discovered a large
5 payment for $1.148 million to a vendor named
6 HCL, related to consulting services for the
7 system integration and implementation of the
8 Company's new Customer Information System
9 (Barcelona Project).
10 Q. Will this specific outside service be required
11 in the rate year?
12 A. No. Based on the Company's response to
13 information request DPS-160, (Exhibit __(RPH-3))
14 the Company stated it will have completed all
15 its contractual obligations with this vendor
16 before the rate year and it does not expect HCL
17 to provide any additional services during the
18 rate year.
19 Q. Should this cost be normalized out of the
20 historic test year before inflation is applied?
21 A. Yes. Since this amount is not expected to occur
22 in the rate year, Staff has removed the amount
23 the Company has forecast for this vendor plus
24 inflation.

Q What is the effect of removing this large nonrecurring vendor payment amount?

A. Staff has reduced contractors & outside services expense cost element by $1.197 million.

Information Services

Q. Has Staff undertaken a review and analysis of the historic year costs associated with the information services expense cost element?

A. Yes. Similar to the outside services cost element, Staff has reviewed the historic year actual cost level and compared it to prior annual calendar year periods for any unusual or nonrecurring charges.

Q. Did Staff observe any charges that would not occur in the rate year?

A. Staff discovered a large payment was made to Microsoft for $613,439 in the historic test year. Based on the response to information request DPS-163, the Company explained that under the terms of its agreement with Microsoft it was required to make an initial payment of $613,439 in the historic year, and the Company is to make the remaining payment of $307,000 in the rate year.

Q. Has Staff made an adjustment to reflect this lower expected rate year payment?

A. Yes. Staff has reduced the rate year information system cost element expense by $.162 million.

Q. How was this adjustment computed?

A. Similar to the above cost element billing, the expenditures associated with information systems are booked to a clearing account. The amounts are accumulated in the information services department clearing account and then allocated to affiliates on a monthly basis. In the case of the information services department clearing account, approximately 48% of the charges into the clearing account remain with the New York Distribution. The Company had applied inflation to the historic vendor payment. Staff's adjustment took the difference between the inflated rate year amount and the amount expected to be paid in the rate year and applied the 48% New York Distribution allocation factor.

Payroll Taxes

Q. Have you made an adjustment to payroll taxes?

A. Yes. I have made an adjustment to payroll taxes to reflect Staff's use of the lower labor O&M

1 percentage of 60.06% rather than the Company's
2 66.33% as discussed in the labor section above.
3 This tracking adjustment lowers payroll tax
4 expense by $.344 million.
5 Q. Does this conclude your testimony at this time?
6 A. Yes.

A.L.J. LECAKES: And did Mr. Gadomski have any exhibits attached to his testimony?

MR. FAVREAU: He did, Your Honor. He has one exhibit. It is DSG1.

A.L.J. LECAKES: Which also had a confidential and public version. Correct?

MR. FAVREAU: That is correct, Your Honor. We would ask that that be marked for identification.

A.L.J. LECAKES: Okay. So the public version will be marked as 118P -- I'm sorry. Yes, the public version and the confidential version as 118C. Next witness?

MR. FAVREAU: Next witness is Robert P. Haslinger. Mr. Haslinger prepared testimony -- direct testimony consisting of 35 pages of questions and answers. We would ask that this testimony be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. At this point in the record, the file Staff Haslinger Testimony should be copied in and the exhibit will be marked as Exhibit -- the affidavit will be marked as Exhibit 119.

*Insert Testimony of Robert P. Haslinger

A.L.J. LECAKES: Mr. Haslinger's exhibits?

MR. FAVREAU: This is four exhibits and they are RPH1 through 4 and we would ask that they be marked for identification.

A.L.J. LECAKES: RPH1 will be given the number 120, RPH2 121, RPH3 122, and RPH4 123. The next witness or panel?

MR. FAVREAU: The next witness would be Richard Davi. Mr. Davi prepared direct testimony -- pre-filed direct testimony consisting of -- we're just checking here how many pages, but the number of pages of questions and answers -- 19 pages of questions and answers and we would ask that this testimony be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. That should be the Staff Davi Testimony file on the Staff disk. Mr. Davi's affidavit marked as Exhibit 124.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

National Fuel Gas Distribution Corp.

Case 16-G-0257

August 2016

Prepared Testimony of:

Richard Davi
Public Utilities Auditor 3
Office of Accounting, Audits and Finance

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

Q. Please state your name and business address.

A. Richard Davi, Three Empire State Plaza, Albany, New York 12223.

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

A. I am employed by the New York State Department of Public Service in the Office of Accounting, Audits and Finance as a Public Utilities Auditor 3.

Q. Briefly outline your educational and professional background.

A. I am a 1986 graduate of Siena College with a Bachelor's Degree in Accounting. From 1986 to 1989, I was employed as a staff accountant at a local CPA firm. In May 1989, I joined the Staff of the Department of Public Service (Staff) in the Office of Accounting, Audits and Finance where I have been employed for the past 27 years. In 1995, I completed the requirements for licensure as a Certified Public Accountant (CPA) in the State of New York. In my current position as a Public Utilities Auditor 3, my responsibilities include the examination of accounts, records, documentation, policies and procedures of regulated utilities to develop

1 issues for rate proceedings, accounting and
2 financing petitions and other general accounting
3 investigations.
4 Q. Have you previously testified in any regulatory
5 proceedings?
6 A. Yes, I have testified in numerous rate
7 proceedings before the Commission. Most
8 recently, I testified in Case 16-G-0058, KeySpan
9 Gas East Corporation d/b/a National Grid; and
10 Case 16-G-0059, The Brooklyn Union Gas Company
11 d/b/a National Grid NY.
12 Q. Please explain the scope of your testimony.
13 A. My testimony will address National Fuel Gas
14 Distribution Corporation's (Distribution or the
15 Company) forecast of uncollectible expense,
16 pension and OPEB expense and property tax
17 expense for the rate year (RY) ending March 31,
18 2018. In addition, I will address the RY impact
19 of the 2014 New York State tax rate change and
20 adjustments to prepayments and accumulated
21 deferred income taxes.
22 Q. Are you sponsoring any exhibits?
23 A. Yes. I am sponsoring two exhibits.
24 Q. Please briefly describe each exhibit.

A. Exhibit__(RMD-1) contains the information requests referenced in my testimony, as well as the Company's responses.
Exhibit__(RMD-2) is a compilation of my workpapers to support my proposed adjustments.

UNCOLLECTIBLE EXPENSE

Q. Briefly describe how Distribution developed its RY forecast of uncollectible expense.

A. The Company used a three-year average of the normalized historical fiscal years (FY) ending September 30, 2013, 2014 and 2015 net write-off data as a percentage of the prior FY 2012, 2013 and 2014 retail and transportation revenues. This resulted in an average factor of 1.67% which the Company then multiplied by the projected 2018 RY retail and transportation revenues to derive the $8.748 million RY forecast of uncollectible expense.

Q. Do you agree with the Company's RY forecast?

A. No. According to Company Exhibit __ (KAF-1) Schedule 1, Sheet 2 of 2, the Company's net write-off factors for the three years were as follows:

FY 2013	1.16%

FY 2014	1.11%
FY 2015	2.57%
3 year average	1.67%

The Company gave the reason for the significant increase in FY 2015 (2.57%) in response to DPS-9 and DPS-156, Exhibit__(RMD-1). The Company explained that upon conversion to the new customer billing system, legacy bad debt transfers will be written-off again and classified as doubtful in the new system. This will result in a one-time posting of $5.983 million, expected to be booked in mid-June 2016, which represents the December 2015 actual active and final bill account receivable balance of bad debt transfers.

Q. Do you agree with including the $5.983 million normalization adjustment in the calculation of the Company's FY 2015 net write-off factor?

A. No. This should be removed for several reasons. First, this is a one-time accounting entry and is not expected to recur in the RY. Second, the accounting entry, expected to be posted in late June 2016, is out of period and does not pertain to FY 2015. Finally, this accounting entry

1 arbitrarily increases the Company's FY 2015 net
2 write-off factor. Additionally, I reviewed
3 Distribution's prior three fiscal years, for the
4 twelve months ending September 30, 2010, 2011
5 and 2012, and none of the net write-factors
6 approached 2.57%. The range of net write-offs
7 for these three years was 1.26% to 1.79%. This
8 provides additional support that the 2.57% FY
9 2015 net write off factor as normalized by the
10 Company is high and should not be used for
11 setting the net write-off percentage for the
12 rate year.
13 Q. Did you verify whether any other of the FYs
14 included normalization adjustments?
15 A. Yes, I did. In response to DPS-156,
16 Exhibit__(RMD-1), the Company indicated that FY
17 2015 was the only year that included a
18 normalization adjustment.
19 Q. What are you proposing for the RY forecast?
20 A. I removed the $5.983 million from FY 2015 net
21 write-offs and recalculated the FY 2015 factor
22 at 1.53%. I also recalculated the three year
23 average as follows:
24 FY 2013 1.16%

FY 2014	1.11%
FY 2015 - revised	1.53%
3 year average	1.27%

I then applied the 1.27% net write-off factor to the forecasted RY retail and transportation revenues of $544.781 million which results in a forecasted amount of $6.919 million for uncollectible expense.

Q. Please quantify your adjustment.

A. Reflecting Staff's forecasted amount decreases the Company's projected uncollectible expense by $1.829 million.

Q. Do you have an alternative methodology for the Commission to consider?

A. Yes, I have two alternatives. My first alternate methodology is to ignore FY 2015 because the amounts are distorted from the normalization adjustment and to use a two-year average instead, specifically using FY 2013 and FY 2014 data. This results in an average net write-off factor of 1.13%. My second alternate methodology is to also ignore FY 2015 and calculate a three-year average using data from FY 2012, 2013 and 2014. This results in an

1 average net write-off factor of 1.18%.
2 Q. Please conclude.
3 A. Considering the three options described above,
4 my recommendation is to use the three year
5 average factor of 1.27%, which takes into
6 account FY 2013, 2014 and 2015. This
7 forecasting methodology is both reasonable and
8 conservative as compared to the other options
9 described.
10 **PENSION AND OTHER POST-EMPLOYMENT BENEFITS (OPEBs)**
11 Q. Please summarize the Company's RY forecast of
12 pension expense.
13 A. Distribution is subject to the Commission's
14 "Statement of Policy and Order Concerning the
15 Accounting and Ratemaking Treatment for Pension
16 and Postretirement Benefits Other than Pensions"
17 issued on September 7, 1996 in Case 91-M-0890
18 (Policy Statement). The Policy Statement allows
19 for reconciliation of the rate allowance with
20 the actual pension and OPEBs expense on its
21 books, with any over or under recoveries
22 deferred. The Company is projecting a rate year
23 pension expense of $14.993 million, which
24 represents the net periodic pension cost as

required under Statement of Financial Accounting Standards No. 87 – Employers' Accounting for Pension (FAS 87), and is provided by the Company's actuary. The Company is also requesting permission to amortize over four years the projected pension related deferred balances that will exist just prior to the beginning of the rate year. The deferred balances to be amortized are made up a projected deferred credit balance of ($3.225) million related to the various pension plans in place, and a projected deferred debit balance of $4.796 million for the internal reserve pension debit balance carrying charges. The amortizations amounts reflected in the Company's rate year forecast are a credit amount of ($0.805) million for the various pension plans in place and a debit amount of $1.198 million for the internal reserve pension debit balance carrying charges. All of these amounts are shown on Company Exhibit__(MPW-3), Schedule 1, Sheet 1 of 2.

Q. Please summarize the Company's RY forecast of OPEBs expense.

A. Distribution is projecting a rate year OPEBs

1 expense of $2.865 million, which is based on the
2 latest known projection by the Company's actuary
3 using the methodology as set forth in Statement
4 of Financial Accounting Standards No. 106 -
5 Employers' Accounting for Postemployment
6 Benefits Other Than Pensions (FAS 106). The
7 Company is also requesting permission to
8 amortize over four years the projected OPEBs
9 related deferred credit balance of ($6.125)
10 million that is expected to exist just prior to
11 the beginning of the rate year. The
12 amortization amount reflected in the Company's
13 rate year forecast is a credit amount of
14 ($1.531) million. These amounts are shown on
15 Company Exhibit__(MPW-3), Schedule 1, Sheet 2 of
16 2.
17 Q. Are you proposing an adjustment to pension and
18 OPEBs expense?
19 A. Yes. While I am accepting the Company's actuary
20 projections for the total FAS 87 pension costs
21 and FAS 106 OPEBs costs for the rate year, I am
22 making a modification to the amount reflected in
23 O&M expense.
24 Q. Please explain your adjustment.

A. After the Company developed its RY forecast for total pension and OPEBs cost, it applied the fringe benefit O&M expense percentage of 65.81% that was developed by Company witness Barber, as shown in Company Exhibit__(JRB-2) Schedule 1, Sheet 5. However, as testified by the Staff Accounting Panel, Staff is recommending an O&M expense percentage of 59.45% be used for allocating the employee benefits to expense. For consistency purposes, I propose to use the same O&M expense allocation rate for pension and OPEBs expense. Applying the O&M expense percentage of 59.45% to the total projected rate year FAS 87 pension costs of $22.782 million, results in a rate year projection of pension expense of $13.544 million. Likewise, applying the same O&M expense percentage to projected FAS 106 OPEBs costs of $4.353 million results in a rate year projection of OPEBs expense of $2.588 million. This results in a $1.449 million reduction to RY pension expense and a $0.277 million reduction to RY OPEB expense.

Q. Do you agree with the Company's projected pension and OPEBs deferral balances?

1 A. At this time I have no opinion on the projected
2 pre-rate year pension and OPEBs deferral
3 balances. While I am agreeing with the four
4 year amortization of the projected deferral
5 balances, as proposed by the Company, the
6 pension and OPEBs deferral balances are not
7 audited in full at this date and remain open for
8 further review and adjustment. As a result,
9 Staff reserves the right to complete its review
10 of the pension and OPEBs deferrals at a later
11 date, using the traditional deferral audit and
12 review process, and will inform the Company on
13 any areas of disagreement. The final
14 disposition of the related deferrals will be
15 decided in the Company's next rate proceeding.
16 Q. Regarding pension and OPEBs deferrals, what date
17 do you consider the beginning point, subject to
18 Staff's review and adjustment?
19 A. Since the Commission approved the Company's
20 pension and OPEB deferral balances in
21 Distribution's last rate case, Case 07-G-0141,
22 my review will begin with deferral activity
23 beginning with the rate year ending December 31,
24 2008.

1 **PROPERTY TAX EXPENSE**

2 Q. Please explain how Distribution developed its RY
3 forecast of property taxes.
4 A. Actual property taxes paid for the historic test
5 year calendar year 2015 were adjusted by the
6 Company's inflation calculation, and further
7 adjusted for projected changes in overall
8 assessments for the twelve months ending March
9 31, 2017 and 2018. These projections were
10 allocated into monthly expense amounts based on
11 the particular tax year and used to develop the
12 RY forecast.
13 Q. How does the Company's RY forecast compare to
14 the actual historic test year level of property
15 taxes?
16 A. The Company's RY forecast of $29.330 million is
17 $0.787 million or 2.8% higher than the historic
18 test year amount of $28.543 million.
19 Q. Do you agree with the Company's RY forecast of
20 property taxes?
21 A. No. The Company's methodology does not take
22 into account the decrease being seen in actual
23 property taxes. A review of Distribution's most
24 recent five calendar years of actual property

1 taxes shows that actual property taxes are
2 trending downward. Specifically, a review of
3 the most recent three year average, for calendar
4 years 2013, 2014 and 2015, indicates a 0.29%
5 decrease. In addition, both of the last two
6 years, calendar years 2014 and 2015, show
7 property tax reductions being realized.
8 Q. Is it common practice for Staff to recommend the
9 use a three-year average to develop a growth
10 rate for projecting property taxes?
11 A. Yes.
12 Q. You indicated that based on the most recent
13 three calendar year actual results, a three year
14 average would equate to a negative growth rate
15 of 0.29%. Are you proposing to use a three-year
16 average negative growth rate to develop the rate
17 year property tax forecast?
18 A. No. In this proceeding it should not be used
19 since a negative growth rate for property taxes
20 would likely not be sustainable.
21 Q. What are you proposing?
22 A. I propose to use the latest known property tax
23 bills with a zero percent growth rate as a proxy
24 for the RY. In response to DPS-56, questions 5

and 6, Exhibit__(RMD-1), the Company provided a breakdown of its latest known property tax bills which total $27.982 million, broken down as follows:

Town and County	CY 2016
School	July 2016 – June 2017
Villages	June 2016 – May 2017
Cities	July 2016 – June 2017

Q. What is the adjustment you are recommending?

A. Adjusting to reflect latest known property taxes results in a downward adjustment of $1.348 million to the Company's RY property tax forecast. I also recommend that this amount be updated for actual property tax bills through the Brief on Exceptions phase of this proceeding.

Q. Are you aware of any other New York State utilities that have a zero percent growth rate for property taxes?

A. Yes. In Case 16-G-0059, The Brooklyn Union Gas Company d/b/a National Grid NY projected a zero percent growth rate in its forecasting of RY property taxes.

Q. Please conclude.

A. Considering the recent trend of decreasing property tax bills for Distribution, my methodology to use latest known property taxes is both reasonable and conservative.

NYS TAX RATE CHANGE

Q. Please summarize the 2014 New York State (NYS) tax rate change.

A. On March 31, 2014, Governor Cuomo signed into law the 2014-2015 Budget Act, which reduced the NYS corporate franchise tax rate from 7.1% to 6.5%, effective for taxable years beginning on or after January 1, 2016.

Q. Did Distribution use the correct tax rate in its forecast of state income tax (SIT) expense for the RY?

A. Yes. The Company's RY forecast of SIT expense was developed using a 6.5% tax rate.

Q. Is there another revenue requirement implication as a result of this tax rate change?

A. Yes. The accounting rules and pronouncements require that Accumulated Deferred State Income Taxes (ADSIT) be reflected on the books at the effective tax rate. As a result, on the effective date of this tax rate change,

1 Distribution will be required to adjust or write
2 down the balance of its (ADSIT) from 7.1% to
3 6.5%. The difference, or 0.6%, is what is known
4 as "excess ADSIT."
5 Q. Is there an estimate of the amount of excess
6 ADSIT for Distribution?
7 A. Yes. In response to DPS-39, Exhibit__(RMD-1),
8 the Company identified $0.702 million as the
9 estimated amount of excess ADSIT at September
10 30, 2016.
11 Q. What is the Company's proposal regarding excess
12 ADSIT?
13 A. The Company's tax expert witness Rizzo was
14 silent on this issue in his pre-filed direct
15 testimony. When asked to clarify this, the
16 Company stated in response to DPS-39: "The
17 Company is proposing to make no adjustment to
18 ADSIT at this time."
19 Q. What are you proposing to do with the excess
20 ADSIT?
21 A. I propose to pass back the excess ADSIT to
22 ratepayers over a three year period. This is
23 shown as a $0.234 million reduction to deferred
24 SIT expense. I also adjusted the balance of

ADSIT that is included in rate base to reflect the pass back for the RY. This is shown separately as a $0.117 million increase to rate base.

Q. How are other NYS utilities accounting for the excess ADSIT?

A. Other NYS utilities are amortizing and passing back to ratepayers the excess ADSIT over multi-year time periods. For example, in Cases 16-E-0060 and 16-G-0061, Consolidated Edison Company of NY is proposing to pass back the excess ADSIT to ratepayers over a three-year period, and in Cases 16-G-0058 and 16-G-0059, KeySpan Gas East Corporation d/b/a National Grid and The Brooklyn Union Gas Company d/b/a National Grid NY, are proposing to pass back the excess ADSIT to ratepayers over a 10 year period.

PREPAYMENTS

Q. Are you proposing an adjustment to the Company's projected RY balance of prepayments?

A. Yes. I am proposing to adjust prepayments to track my ($1.348) million adjustment to property tax expense. I estimate the adjustment to prepayments to be ($0.408) million calculated as

1 follows. My ($1.348) million property tax
2 adjustments represents a 4.60% reduction to the
3 Company's RY forecast. I then applied this same
4 percentage (4.60%) to the Company's $8.865
5 million RY forecast of prepaid property taxes to
6 arrive at my adjustment of ($0.408) million.
7 **ACCUMULATED DEFERRED INCOME TAXES (ADIT)**
8 Q. Are you proposing adjustments to the Company's
9 projected RY balance of ADIT?
10 A. Yes, I am proposing two separate adjustments.
11 My first adjustment tracks the ADIT impact
12 related to the ($4.465) million plant in service
13 adjustments Staff is recommending as discussed
14 in the testimony of the Staff Gas Infrastructure
15 and Operations Panel. I estimate the ADIT
16 impact to be approximately $1.116 million based
17 on a rate of 25% per plant in service
18 adjustment. The 25% rate is my best estimate at
19 this time and subject to correction provided the
20 Company can provide Staff with sufficient detail
21 to calculate the exact amount of the ADIT
22 impact.
23 Q. Explain your second adjustment to ADIT.
24 A. My second adjustment tracks the ADIT impact

1 related to my ($1.829) million adjustment to
2 Uncollectible Expense. I estimate the ADIT
3 impact to be approximately ($0.366) million
4 calculated as follows. I multiplied ($1.829)
5 million by the combined Federal and State income
6 tax rate of 40% and then divided this amount by
7 two to arrive at an average rate base amount.
8 Q. Does this conclude your testimony at this time?
9 A. Yes, it does.

A.L.J. LECAKES: Mr. Davi's exhibits?

MR. FAVREAU: Mr. Davi had two exhibits RND1 and 2 and we would ask that they be marked for identification.

A.L.J. LECAKES: RND is 125, RND-1 is 125, RND-2 is 126. Next witness?

MR. FAVREAU: Is a panel, Your Honor, and it's the Accounting Panel consisting of John P. Castano and Ronald F. Calkins. They submitted pre-filed direct testimony consisting of 44 pages of questions and answers.

A.L.J. LECAKES: And those affidavits they're -- they're two separate affidavits?

MR. FAVREAU: Two separate affidavits, Your Honor.

A.L.J. LECAKES: Okay. We'll mark them separately then. I'll take the affidavits now. Thank you. The affidavit of Ronald Calkins, C-A-L-K-I-N-S, will be marked as Exhibit 127. The affidavit of John Castano, C-A-S-T-A-N-O, will be marked as Exhibit 128 --

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

National Fuel Gas Distribution Corporation

Case 16-G-0257

September 2016

Prepared Testimony of:

Staff Accounting Panel

Ronald F. Calkins
Supervisor Utility Accounting
and Finance

John P. Castano
Auditor Trainee 2

Office of Accounting, Audits and
Finance
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Q. Would you please state your names and business addresses?

A. We are Ronald F. Calkins, and John P. Castano, trial staff of the Department of Public Service (Staff). Mr. Calkins business address is Three Empire State Plaza, Albany, New York 12223, and Mr. Castano's business address is Three Empire State Plaza, Albany, New York 12223.

Q. Mr. Calkins, by whom are you employed and in what capacity?

A. I am employed by the Department of Public Service as a Supervisor, in the Office of Accounting, Audits and Finance.

Q. Mr. Calkins, please summarize your education and work experience?

A. I graduated from Siena College with a B.B.A. in Accounting. In June of 1969, I joined the Department of Public Service.

Q. Mr. Calkins, have you previously testified before the Commission?

A. Yes. I have testified in various electric, gas and telephone rate proceedings.

Q. Mr. Castano, what is your position at the Department?

A. I am an Auditor Trainee 2 in the Office of Accounting, Audits and Finance.

Q. Please describe your educational background and professional experience.

A. I graduated from the State University of New York Institute of Technology in 2013 with Bachelor of Science degree in Accounting. I have been employed by the Department since September 2014.

Q. Please describe your responsibilities with the Department.

A. I am responsible for examining accounts, records, documentation, policies and procedures of regulated utilities to ensure they comply with the Public Service Law and Commission rules, regulations, and guidance.

Q. Mr. Castano, have you previously testified before the Commission?

A. Yes. I have testified before the Commission in New York State Electric and Gas Cases 15-E-0283 and 15-G-0284; Rochester Gas and Electric Cases 15-E-0285 and 15-G-0286; KeySpan East Gas Case 16-G-0058; and Brooklyn Union Gas Case 16-G-0059, rate proceedings. I have also been

1 involved in municipal electric rate proceedings.
2 Q. What is the purpose of your testimony?
3 A. We will address various issues of the rate
4 filing by National Fuel Gas Distribution
5 Corporation (Distribution or the Company),
6 specifically: (1) Area Development (2) Employee
7 Benefits (3) Materials expense (4) PSC Audits
8 and Assessments (5) Rate Case expense (6)
9 Inflation, and (7) Earnings Base/Capitalization.
10 Q. Please summarize Staff's recommendation
11 regarding the Company's revenue requirement.
12 A. In its April 28, 2016, initial filing,
13 Distribution requested a $41.697 million annual
14 increase in gas revenues. Staff is recommending
15 a gas base rate increase of $1.808 million, or
16 approximately $39.9 million less in revenues
17 than the amount requested by the Company.
18 Exhibit___(SAP-1), Schedule 6, lists every
19 adjustment Staff is proposing that makes up this
20 $39.9 million revenue requirement differential
21 with the exception of Staff's return on equity.
22 Q. Is this Panel sponsoring any Exhibits?
23 A. Yes, we are sponsoring 4 Exhibits;
24 Exhibit___(SAP-1), Exhibit___(SAP-2),

1 Exhibit___(SAP-3), and Exhibit___(SAP-4).
2 Q. Would you describe Exhibit___ (SAP-1-Corrected)?
3 A. Exhibit___ (SAP-1-Corrected) is our rate year
4 cost of service presentation for Distribution,
5 consisting of 10 schedules. Schedule 1
6 summarizes our projection of gas operating
7 income, rate base and rate of return for the
8 rate year ending March 31, 2018, and includes
9 our proposed base rate increase. Schedule 1 is
10 supported by Schedules 2 through 10. Schedule 2
11 is a summary of operating expenses. Schedule 3
12 is the computation of state and federal income
13 tax. Schedule 4 is a summary of rate base.
14 Schedule 5 is a summary of the capital matrix.
15 Schedule 6 is a listing of Staff's adjustments.
16 Schedule 7 is a calculation of taxes other than
17 income tax. Schedule 8 is the calculation of
18 the interest expense. Schedule 9 is the
19 calculation of supplemental cash working
20 capital, and Schedule 10 is the calculation of
21 Staff's revenue requirement, and retention
22 factor.
23 Q. Would you describe Exhibit___(SAP-2)?
24 A. Exhibit___(SAP-2) includes the Information

1 Request (IR) responses that we rely upon
2 throughout our testimony. We will refer to
3 these IRs by the number assigned by Staff, e.g.,
4 DPS-41.
5 Q. Would you describe Exhibit___(SAP-3)?
6 A. Exhibit___(SAP-3) provides the derivation of
7 Staff's recommended Earnings Base/Capitalization
8 adjustment presented as a component in rate
9 base.
10 Q. Would you describe Exhibit___(SAP-4)?
11 A. Exhibit___(SAP-4) is a compilation of the
12 workpapers we used to support our proposed
13 adjustments.
14 Q. Is it fair to directly compare Staff's $2.524
15 million recommended revenue requirement increase
16 with Distribution's requested revenue
17 requirement increase of $41.697 million?
18 A. No. It is important to note that, in developing
19 our recommended revenue requirement, we have
20 identified the costs of all of the Company's low
21 income programs as line items in the revenue
22 requirement, rather than through a combination
23 of rate design and revenue requirement as has
24 been done previously. This increases the

Company's filed revenue requirement increase by approximately $2.6 million, resulting in what would have been a base rate increase request by Distribution of approximately $44.297 million. The Staff Accounting Panel Exhibit___ (SAP-1-Corrected), Schedule 6 details all of the low income revenue and expense adjustments made to the revenue requirement presentation.

Q. Would you please explain your proposed adjustments to the Company's rate case filing?

A. Yes. We will address the issues in the sequential order we previously described.

OPERATION AND MAINTENANCE EXPENSE

Area Development Program

Q. Please explain the Area Development Program (ADP).

A. According to the direct testimony of the Company's Energy Services Panel at page 42, the ADP was established to provide grants to community based organizations or local development authorities, or directly to project applicants, for specific economic development projects in order to expand economic opportunities in the Company's service

territory.

Q. Please explain how ADP is currently funded.

A. The ADP is currently funded at a level of $1.250 million, of which $1.0 million is recovered through base rates, and $.250 million of the program is funded using the customers' 85% share of off-system sales and capacity release.

Q. What is the Company proposing for the rate year?

A. The Company is proposing to fund the entire program through base rates.

Q. What is the basis for the Company's proposal to replace funding from off-system sales and capacity release to base rates?

A. Referring to page 79 of the direct testimony of the Company's Cost of Service and Rate Design Panel, "The ratepayer share of off-system sales and capacity release proceeds would first be utilized to eliminate any deferral balances accumulated from the system upgrade and modernization tracking mechanism. Any remaining balance for the ratepayer share of off-system sales and capacity release would be refunded to customers."

Q. Do you agree with the Company's proposal to fund

1 the entire cost of the ADP through base rates?
2 A. Yes. We find the Company's proposal to entirely
3 fund the ADP through base rates to be
4 reasonable.
5 Q. Please explain why you agree with the Company's
6 proposal.
7 A. Including the entire ADP rate allowance in base
8 rates through an operation and maintenance (O&M)
9 expense cost element allows for consistent
10 collection and funding of the Company's ADP and
11 provides transparency for the total allowed cost
12 of the program.
13 **EMPLOYEE BENEFITS**
14 Percentage of Benefits Expensed
15 Q. What percentage of employee benefit costs did
16 the Company forecast would be expensed in the
17 rate year?
18 A. The Company forecast 65.81% of employee benefit
19 costs would be charged to O&M expense in the
20 rate year, with the remaining 34.19% charged to
21 capital and other non-O&M accounts.
22 Q. What was the basis for this estimate?
23 A. The Company determined 65.81% was the benefits
24 O&M percentage charged to expense in the

1 historic test year, and that it should be
2 carried forward and used in the rate year
3 projections.
4 Q. Is the employee benefits (fringe benefits) O&M
5 expense percentage rate the same as the labor
6 O&M expense percentage rate?
7 A. No. In theory it should be, as fringe benefits
8 should follow the same O&M percentage as labor
9 costs. However, when computing the O&M expense
10 percentage for fringe benefits, the Company
11 noted an adjustment needed to be made to the
12 labor O&M expense percentage calculation to
13 remove certain benefits that have been included
14 as part of labor expense such as; special
15 annuity, a portion of other employee benefits,
16 military duty, jury duty, employee sick/injured,
17 and other approved employee absence. The Company
18 makes an adjustment reducing projected rate year
19 labor by $1.204 million, removing certain
20 benefits that have been included as part of
21 labor expense, when calculating the expense
22 percentage for employee benefits.
23 Q. How does the Company calculate the O&M
24 percentage for labor costs in the rate year?

A. The Company forecast 66.33% of total Distribution labor costs would be expensed in the rate year. This percentage is based on the Company's determination and analysis of the labor that was charged during the historic year to O&M expense versus total labor costs. The Company simply carried forward to the rate year what it determined to be a historic year expense factor.

Q. Did the Company identify an error in its labor O&M expense percentage calculations?

A. Yes, after Staff questioned the Company on a potential error in its calculations, it provided an updated expense percentages for labor, and employee benefits. Referring to the Company's response to DPS-176 (Exhibit___(SAP-2)), it states "As noted in the Company's follow-up to DPS-4 posted on 6/25/16, the Company discovered that the O&M percent of 66.33% for labor in Exhibit___(JRB-2), Schedule 1, Sheet 5 was incorrect. The correct O&M percent for labor is 62.57%. Additionally, as a result of the correction to the labor O&M percentage, the

1 corrected O&M percent for benefits is 61.95%."
2 Q. Does Staff agree with the Company's updated
3 expensed labor percentage of 62.57%?
4 A. No. In the testimony of Staff witness Haslinger
5 and the associated Exhibit___(RPH-2), Staff
6 shows the actual Distribution New York labor
7 expense per the Company's books, after charges
8 to other jurisdictions (other affiliates) are
9 taken into account, results in an O&M expense
10 percentage allocation of 60.06%. Staff witness
11 Haslinger recommends the 60.06% should be used
12 to determine the percentage of New York payroll
13 ultimately charged to O&M expense.
14 Q. Do you agree with the Company's updated employee
15 benefits O&M expense percentage of 61.95%, as
16 referenced in the response to DSP-176
17 (Exhibit___(SAP-2))?
18 A. No. The employee benefits O&M expense percentage
19 should basically track the labor O&M expense
20 percentage. As shown in the Staff
21 Exhibit___(RPH-2) discussed above, for the
22 historic year, New York Distribution had a gross
23 payroll of $79.849 million and of that gross
24 payroll, $47.960 million was charged to expense,

after allocation of labor to other jurisdictions (affiliated companies). This results in Staff recommending the more appropriate labor O&M expense percentage to be used in projecting rate year labor expense is 60.06%. Taking this labor O&M expense percentage, and following the same methodology the Company employs in determining the fringe benefit O&M expense percentage, we have computed a more appropriate benefits O&M expense percentage to be applied to rate year employee benefits. Specifically, in our calculation, we have reduced the historic year gross payroll of $79.840 million, by the $1.204 million of benefit labor identified by the Company, to derive an employee benefits O&M expense percentage of 59.45%.

Q. Please quantify your adjustment.

A. In quantifying the total adjustment, we have applied our calculated 59.45% O&M expense allocation to the same pool of employee fringe benefits that the Company identified it applied the O&M expense percentage for projecting the rate year expenses. Specifically, we recommend a downward adjustment to pension expense of

1 $1.449 million, a downward adjustment to OPEBs
2 expense of $.277 million, and a downward
3 adjustment to the 401(k) plan expense of $.166
4 million. The downward adjustment to pension
5 expense and OPEBs expense is discussed in the
6 testimony of Staff Witness Davi. The downward
7 adjustment to 401(k) follows the same
8 methodology as the Company. We applied Staff's
9 benefits O%M expense percentage of 59.45% to the
10 Company's rate year computation. This
11 adjustment reduces the Company's 401(k) rate
12 year amount charged to O&M expense by $.166
13 million.
14 Q. Why are you not recommending similar adjustments
15 be made to the remaining pool of employee
16 benefits including health care expense, group
17 life insurance, dental plan costs and long term
18 disability?
19 A. The Company has not forecasted the rate year
20 expense associated with these benefits in the
21 same manner as pension expense, OPEBs expense
22 and 401(k) plan expense.
23 Q. Please explain.
24 A. For the remaining pool of employee fringe

1 benefits, rather than explicitly projecting out
2 the rate year cost for each, the Company has
3 projected the rate year expense by simply taking
4 the historic test year expense amounts, with a
5 slight normalization in the case of health care
6 expense, and added inflation at a rate of 4.27%.
7 By using the historic test year expense as the
8 base, a historic test year O&M expense
9 percentage has already been factored in. Staff
10 has reviewed the gross historic year costs for
11 these benefits and made a comparison to the
12 actual historic year O&M expense amounts, and
13 has determined the underlying O&M expense
14 percentage used is reasonable. No further
15 adjustments to the Company's projected rate year
16 expenses for the remaining pool of employee
17 fringe benefits is required.
18 Other Benefits
19 Q. Please explain "other benefits".
20 A. Based on the Company response to DPS-41
21 (Exhibit___(SAP-2)), "other benefits" represent
22 various miscellaneous benefits such as tuition
23 aid, employee wellness, programs, safety
24 clothing, etc., with an offset by credits for

1 benefits provided to and charged to other
2 affiliates. The Company refers to this piece of
3 "other benefits" as "loading for other
4 benefits."
5 Q. How much "other benefits" did the Company incur
6 during the historic test year ending December
7 31, 2015?
8 A. As shown in Exhibit___(JRB-2), Schedule 2, Sheet
9 5, the Company incurred $.243 million of "other
10 benefits" that represents certain miscellaneous
11 benefits, offset by credits for benefits
12 provided and charged to other affiliates of
13 ($1.116) million, for a total historic test year
14 expense credit of ($.873) million.
15 Q. How does this level of "other benefits" compare
16 to the amount forecasted in the rate year.
17 A. The Company initially increased the costs of the
18 miscellaneous benefits by inflation of 4.27% for
19 a total rate year expense projection of $.254
20 million. Then the Company adjusts the historic
21 test year credits for benefits provided and
22 charged to other affiliates credit by $.618
23 million as a means to project the benefits
24 charged to affiliates in the rate year., This

adjustment nets in a credit amount of ($.498 million) for the loadings of other benefits. Netting the miscellaneous benefits of .254 million, against the Company's rate year forecast credit amount of ($.498 million) results in a net rate year credit of ($.245) million, or, a 71% decrease from the historic test year. The following table summarizes the Company's presentation of "other benefits" as shown in Exhibit __ (JRB-2) Schedule 2 Sheet 5.

	($ in Millions)	
	HTY	RY
Other Benefits	0.243	0.254
Charged to Affiliates	(1.116)	(0.498)
Net Expense (Credit)	(0.873)	(0.245)

Q. How did Distribution calculate the credit for benefits provided to other affiliates for the rate year?

A. The Company's response to DPS-204 (Exhibit___(SAP-2)), explains it first takes the costs associated with sickness and injury, other approved absences, military duty, and jury duty, totaling $1.204 million as a means to project the rate year loading credit as an

1 offset to other benefits. The Company indicates
2 the O&M benefits percentage it has calculated is
3 65.81%, therefore the remaining 34.19% is
4 considered non-O&M. The Company multiplies the
5 34.19% by the amount reflected for sick & other
6 absence labor plus the total of miscellaneous
7 other benefits, amounts of $1.204 million and
8 $.254 million, in forecasting the rate year
9 benefits provided and charged to other
10 affiliates in the credit amount of ($.498)
11 million.
12 Q. Do you agree with the Company's rate year
13 calculation for the benefits provided and
14 charged to other affiliates?
15 A. No. First, the rationale the Company provided
16 for the explanation of the calculation using the
17 rate year labor forecast for sick & other
18 absence multiplied by the non-O&M percentage, as
19 a means to project the rate year loading credit
20 to "other benefits" is complex and difficult to
21 follow. Second, the rationale for the
22 methodology the Company is using to project the
23 rate year expense is difficult to understand,
24 and illogical. Third, we believe the Company's

1 rate year projection is overstated.
2 Q. Explain why the Company's rate year calculation
3 for the benefits provided and charged to other
4 affiliates is complex, difficult to follow , and
5 overstated?
6 A. The Company's rate year calculation for the
7 benefits provided and charged to other
8 affiliates is not correct because typically,
9 there is a direct correlation between labor
10 expense and the amount of loading of benefits.
11 We believe the Company's rate year projection is
12 overstated because, as labor cost increases, and
13 assuming the benefit loadings rate remains
14 constant, the associated cost of loadings of
15 benefits increases.
16 Q. Is the Company projecting the associated labor
17 loaned to jurisdictions will decrease during the
18 rate year?
19 A. No. As discussed in Staff witness Haslinger's
20 testimony, the Company actually neglected to
21 properly include labor loaned to jurisdictions
22 in the rate year forecast. In his testimony,
23 Mr. Haslinger, states "Staff's forecast includes
24 the $5.8 million amount for labor the Company

should have included in its rate year forecast for labor loaned to other jurisdictions. Staff has increased the amount of labor loaned to other jurisdictions from the normalized period to the rate year by the rate of increase used by the Company for its overall labor forecast." The Company increases its labor forecast by a rate of increase of 3.94% in projecting its rate year labor costs, which is derived by dividing the projected rate year expensed labor costs of $57.561 million by the normalized historic test year labor expensed costs of $55.377 million for an increase of 3.94%, as shown in Exhibit___(JRB-2), Schedule 1, Sheet 1.

Q. Are you recommending any adjustments to the Company's other benefits expense forecast?

A. Yes, we are recommending two adjustments. First, we are removing the Company's calculated rate year adjustment, an increase of $.618 million, from its rate year forecast. Second, we recommend increasing the identified historic test year credit amount of loading for other benefits that is associated with labor loaned to other jurisdictions by the rate of 3.94%, which

is the same percentage increase used by the Company in projecting out its overall labor forecast. This second adjustment increases the credit of benefits loaned to other jurisdictions by ($.044) million. The total adjustment we are making to other benefits expense is a downward adjustment of $1.160 million.

MATERIALS

Q. Please describe what the category of materials includes.

A. The Company response to DPS-32 (Exhibit___(SAP-2)), indicates the material cost category includes all material charged to expense, undistributed accounts and deferred debits. Some examples of the items charged to materials are: freight, fuels and oils, sand-stone-gravel, pipe-tubing-casing, regulators-valves-fittings, compressor engines and parts, janitorial supplies, and meter parts.

Q. How much in materials expense did the Company incur during the historic test year ending December 31, 2015?

A. As shown in IR DPS-33 (Exhibit___(SAP-2)), the Company incurred $4.821 million during the

1 historic test year.
2 Q. How does this level of material expense compare
3 to the amounts actually incurred in previous
4 years.
5 A. According to IR DPS-8 (Exhibit___(SAP-2)),
6 materials expense levels incurred in previous
7 years were much lower than the Company's
8 historic test year level of $4.821 million. For
9 calendar years ending December 31, 2013, and
10 2014, the incurred material expense was $2.786
11 million and $3.375 million, respectively.
12 Q. Did the Company identify the reason(s) for the
13 increase of $1.447 million, or 43%, in materials
14 expense in the historic test year as compared to
15 the previous twelve month period?
16 A. Yes. In response to DPS-81, the Company
17 identified the major cause to be associated with
18 "INV-Issues NYD," which represents material
19 issued from a NY Distribution warehouse or
20 stockroom. In review of Attachment 1 of the
21 response to DPS-81 (Exhibit___(SAP-2)), the
22 Company provided a breakdown of material expense
23 by month beginning with January 2013 through
24 April 2016. In September 2015, the material

1 issued was $1.239 million, or 366% greater than
2 the average $.267 million incurred for the
3 remaining months of calendar year 2015, and 517%
4 greater than the average $.200 million incurred
5 for the months January through April 2016.
6 Q. Did the Company provide a reason for the
7 significant increase in materials expense that
8 was experienced in the historic year?
9 A. Yes. In the its response to IR DPS-154
10 (Exhibit___(SAP-2)), the Company indicated the
11 increase was due to a concerted effort of the
12 Company to meet DPS Staff directives regarding
13 leak repair and reducing year end leak backlogs.
14 Q. Does the Company consider this large inventory
15 expense in September 2015 to be abnormal and
16 non-recurring?
17 A. No. The Company's response to Staff IR DPS-154
18 (Exhibit___(SAP-2)), stated that the Company
19 does not consider this expense as abnormal and
20 non-recurring, and that it expects the effort
21 and associated annual costs will recur. In its
22 response to IR DPS-145 (Exhibit___(SAP-2)), the
23 Company explained that the increase was due to
24 taking the initiative of reducing the Company's

total outstanding year end leak backlog, which has associated increases in inventory costs. The Company's stated its dedicated effort to reduce its backlog of total leaks resulted in increasing costs, such as the corresponding increase in the amount of leak repair tools and materials needed to perform the actual repairs. The Company expects to continue this effort and to annually incur the associated costs.

Q. Has the Company been decreasing its backlog of total leaks?

A. Yes. Based on a review of the State of New York Department of Public Service (NYDPS) 2015 Gas Safety Performance Measures Report (16-G-0254), Appendix F, page 47, the Company has been steadily decreasing its backlog of total leaks, as follows;

2012	2013	2014	2015
4,056	3,575	3,053	2,066

Q. Has the Company been decreasing its backlog of potentially hazardous leaks?

A. Yes. Based on the same NYDPS 2015 Gas Safety Performance Measures Report, Appendix E, page 45, the Company has been steadily decreasing its

backlog of total leaks, as follows;

2012	2013	2014	2015
58	57	1	0

Q. Has the Company initiated an accelerated leak prone pipe (LPP) replacement program?

A. Yes. Referring to the direct testimony of Company witness House, at page 9, he states "Beginning in 2017, the Company is proposing to further accelerate its LPP replacements beyond its already aggressive 95 mile annual replacement rate, increasing LPP replacements over the next two years to reach a 105 mile average annual replacement rate by 2018."

Q. Will the acceleration of LPP help reduce the amount of needed leak repairs, and thus reduce the amount of materials needed to repair the leaks?

A. Yes. There is a direct correlation between LPP replacement and the number of overall leaks. Removal or replacement of leak prone pipe reduces the amount of leaks. In the testimony of the Staff Gas Safety Panel (GSP), the panel states, "Removing leak prone pipe should drive down the number of active leaks, will lead to a

1 decline in leakage rates on the distribution
2 systems, and also reduce overtime and operating
3 and maintenance costs associated with responding
4 to leak calls and monitoring leaks."
5 Q. Do you recommend the Commission accept the
6 Company's proposed rate year projection for
7 materials expense that is supported by using the
8 actual historic test year amount with an
9 increase for inflation?
10 A. No. Unlike the Company, we believe the
11 decreasing backlog of total leaks and the
12 accelerated replacement of leak prone pipe will
13 decrease the amount of leak repair tools and
14 materials needed to perform the actual repairs
15 in a year. Additionally, after a review of the
16 historic test year actual costs, we have
17 determined the level incurred is not indicative
18 of a typical year, and it should not be used to
19 forecast the rate year materials expense.
20 Rather, we recommend the use of a three year
21 historical average.
22 Q. Please explain why you believe a three year
23 average should be used to determine the rate
24 year level for materials expense, rather than

relying on the historic test year actual costs.

A. A review of the monthly materials expense charges over a forty month period, as portrayed in the Company's response to DPS-81 (Exhibit___(SAP-2)), indicates the one month of September 2015 was abnormally high. Rather than normalizing out the month of September 2015 to determine a reasonable twelve month rate year materials expense allowance, Staff recommends the more conservative approach of using a multi-year average. While this method still has somewhat of a normalizing effect, it more reasonably considers that there will be, and allows for, the occurrence of year-to-year changes. The use of an averaging approach for forecasting the materials expense cost element will smooth out the year to year changes and will produce a more reasonable forecast. Therefore, we recommend a three year historical average be used by the Commission, adjusted for inflation.

Q. Please quantify your adjustment.

A. This adjustment decreases Distribution's materials expense forecast by $1.366 million.

PSC AUDITS AND ASSESSMENTS

Q. Please describe the PSC Assessment cost element.

A. Section 18-a of New York State's Public Service Law provides that all costs and expenses of the department and commission shall be borne by the public utility companies, corporations, and persons subject to the commission's regulation. The New York State Department of Public Service (NYDPS) is required to collect a Temporary State Energy and Utility Service Conservation Assessment (Temporary State Assessment or TSA), a General Assessment which supports the costs of the Department and an assessment for the New York State Energy Research and Development Authority (NYSERDA) from each utility. The Temporary Assessment is collected via a surcharge, with the remaining two components - - the General and NYSERDA assessments, are collected through base rates. The NYDPS bills utilities twice a year, once in February and once in August for the General and Temporary assessments. The initial February billing is based on an estimate of the utility's intrastate revenues from the prior calendar year. In

1 August of the same year, a revised bill is
2 rendered with an adjusted assessment amount
3 based on actual intrastate revenues for the
4 prior calendar year. In addition, the revised
5 August bill includes an additional amount for
6 the NYSERDA assessment.
7 Q. What is Distribution's proposal for recovering
8 rate year costs related to the PSC Assessment?
9 A. Distribution included $2.370 million for the
10 rate year forecast of the general PSC
11 Assessment. This amount was based on rate year
12 2 of the rate extension plan in Case 13-G-0136.
13 Distribution is proposing to continue this level
14 in the rate year, subject to full
15 reconciliation, with any difference collected or
16 refunded through a tariff surcharge/refund
17 included in the Delivery Adjustment Clause.
18 Q. Are you proposing any adjustments to the
19 forecast of the general PSC Assessment?
20 A. Yes. We recommend that the expense be updated
21 to reflect the latest General assessment amount
22 included and billed to Distribution in the
23 August 10, 2016 billing, with an increase for
24 inflation allowed from April 1, 2017 through the

end of the rate year period. The August 10, 2016 billing to Distribution, for the fiscal year period April 1, 2016 through March 31, 2017, indicates the general PSC Assessment for Distribution is $1.409 million. Applying inflation of 1.85%, or $.026 million, results in a rate year forecast for the general PSC assessment of $1.435 million.

Q. Please quantify your adjustment.

A. Comparing Staff's recommended rate allowance of $1.435 million to the Company's proposed $2.370 million, results in a downward adjustment of $.935 million.

Q. Do you agree with the Company's proposed reconciliation of the general PSC Assessment?

A. No. We do not believe full reconciliation of the PSC General Assessment is appropriate nor is it necessary. The Temporary State Assessment (TSA) is set to expire March 31, 2017, with customer collections scheduled to end December 2017. Prior to Case 09-M-0311, the general PSC Assessment was a non-reconciling item recovered through base rates. In fact, the Company's response contained in DPS-108 (Exhibit___(SAP-

2)), confirms this historical treatment. The Company states "Historically, before docket 09-M-0311, which initiated the collection of the TSA, the amount allowed for in base rates was for the General Assessment portion." With the TSA set to expire during the rate year, recovery of the General assessment will revert back to how it was treated historically - through base rates as a non-reconciling item.

Q. Please describe the PSC Audit cost element?

A. Based on the direct testimony of Company witness Friedrich-Alf, at pages 4-5, she states "Pursuant to Section 66(19) of the Public Service Law, which requires audits of the major electric and gas utilities at least once every five years and gives the Commission authority to select a consulting firm and direct the utility to pay the costs of the audit…"

Q. Is the Company anticipating a comprehensive management audit during the rate year?

A. Yes. The Company has included $.838 million in the rate year forecast for expenses associated with an expected management audit.

Q. Are you making any adjustments to the Company's

1 rate year forecast for its management audit
2 expense?
3 Q. Yes. Based on the direct testimony of Staff
4 witness Lavery, there is no management audit
5 anticipated to be conducted during the rate
6 year, and as such, he recommends the associated
7 costs be removed from the Company's rate year
8 forecast. The removal of the forecasted
9 management audit expense is a reduction to O&M
10 expense of $.838 million.
11 Q. Are you making any additional adjustments to PSC
12 Audits and Assessments?
13 A. Yes. As mentioned above the revised August 10,
14 2016 regulatory assessment bill from NYDPS to
15 Distribution includes a NYSERDA assessment
16 portion, often referred to as the "ERDA"
17 assessment. Instead of reflecting the ERDA
18 assessment within the PSC audit and assessment
19 cost element, the Company includes the NYSERDA
20 assessment within the separate and distinct cost
21 element of Research Development and
22 Demonstration (RD&D). Exhibit___(RMFA-2),
23 Schedule 2, Sheet 3 indicates the Company
24 included an amount of $.902 million for the

1 NYSERDA assessment contained on the August 2015
2 invoice in the RD&D cost element.
3 Q. Do you agree with the Company reflecting the
4 NYSERDA assessment piece in the RD&D cost
5 element?
6 A. No. The NYSERDA assessment should be reflected
7 in the PSC audits and assessment cost element as
8 they are directly related the NYDPS annual
9 assessment. We recommend removal of the $.902
10 million from the RD&D cost element, and transfer
11 the same amount to the PSC audit and assessment
12 cost element.
13 Q. Do you have any further adjustments to the
14 NYSERDA assessment?
15 A. Yes. Similar to our recommendation on the
16 general PSC assessment, we recommend that the
17 NYSERDA assessment be updated to the latest
18 known assessment amount reflected in the August
19 10, 2016 billing, with an increase allowed for
20 inflation from the period April 1, 2017 through
21 the end of the rate year. The August billing to
22 Distribution, for the fiscal year period April
23 1, 2016 through March 31, 2017, indicates the
24 NYSERDA for Distribution is $1.0 million.

1 Applying inflation of 1.85%, or $.019 million,
2 results in a rate year forecast for the NYSERDA
3 assessment of $1.019 million.
4 Q. Please quantify your adjustment.
5 A. Comparing Staff's recommended rate allowance of
6 $1.019 million to the Company's proposed $.902
7 million, results in a total upward adjustment of
8 $.117 million.
9 **RATE CASE EXPENSE**
10 Q. Please explain the rate case expense the Company
11 included in the rate filing.
12 A. The Company has included an amount of $.185
13 million as the forecasted rate case expense.
14 Distribution estimates the rate case cost is for
15 preparation and follow-up work related to this
16 rate filing and are mainly comprised of services
17 from outside consultants and contractors.
18 Q. What specific costs are included in the
19 Company's request for rate case expense?
20 A. Based on the Company's response to DPS-16
21 (Exhibit___(SAP-2)), the rate year forecast of
22 $.185 million for rate case expense was based on
23 conversations with outside consultants engaged
24 by the Company for this proceeding and is broken

1 down as follows:

Rate of Return witness	$ 90,000
Legal Expenses	55,000
Depreciation witness	40,000
Total	$185,000

6 Q. Do you agree with Distribution's projection of
7 rate case expenses?
8 A. Yes. We agree with the Company's projection of
9 the rate case expense. However, we disagree
10 with the time period for recovery of these
11 costs.
12 Q. Please explain.
13 A. The Company seeks recovery of rate case expenses
14 over a one year period, even though history
15 shows this is not an annual recurring expense
16 for this Company. Furthermore, the Commission
17 typically allows recovery of rate case expense
18 over a multi-year period.
19 Q. What is the Company's history of rate filings?
20 A. Distribution's last full rate filing was in
21 2007, approximately 9 years ago. Given the
22 length of time between these rate proceedings,
23 we recommend the projected rate case expense be
24 amortized over a three year period, and reflect

1 the unamortized deferred rate case expense and
2 the associated accumulated deferred tax balances
3 in rate base for the rate year. Our adjustment
4 reduces the rate year O&M expense forecast by
5 $.123 million for an annual recovery of $.062
6 million, and increases the Company's rate year
7 rate base by $.094 million net of accumulated
8 deferred federal and state income taxes.
9 **INFLATION**
10 Q. What inflation rate did the Company use to
11 forecast many of the historic test year expenses
12 in the rate year?
13 A. The Company used an inflation rate of 4.2744%
14 for the period January 1, 2016 through March 31,
15 2018.
16 Q. Do you agree with the Company's rate of
17 inflation?
18 A. No. The Commission traditionally uses the Gross
19 Domestic Product Price Deflator, commonly
20 referred to as the GDP price deflator, to
21 forecast inflation. As of July 22, 2016, the
22 GDP price deflator inflation rate was 3.77% for
23 the period January 1, 2016 through March 31,
24 2018.

Q. Are you proposing an adjustment to reflect this rate of inflation?

A. Yes. The most current inflation estimate of 3.77%.

Q. How did you calculate the inflation adjustment?

A. We compiled a list of all O&M expense components in which the Company used inflation to calculate the rate year forecast. To avoid a potential double count, we removed from the list any expense item where we have already made specific adjustments and have used the updated inflation rate in computing those adjustments. We have calculated the rate year forecast of the remaining unadjusted expenses using the updated inflation rate. Comparing our forecast to the Company's forecast of these expenses, we have derived a total inflation adjustment of $.232 million.

EARNINGS BASE VERSUS CAPITALIZATION (EB/CAP)

Q. Please explain the EB/CAP Adjustment.

A. The EB/CAP adjustment aligns the utility rate base with its capitalization devoted to utility service. Utilities are allowed a return only on the capital devoted to utility service so that

1 ratepayers pay no more and utilities recover no
2 less than the indicated return on the capital
3 supporting utility operations.
4 Q. What is the capitalization used in the EB/CAP?
5 A. Capitalization for the EB/CAP represents funds
6 provided by investors and ratepayers supporting
7 utility operations, on which utilities pay a
8 return. Some examples of capitalization, as
9 used here, include: common stock, retained
10 earnings, advances from associated companies,
11 and short term debt. Accordingly, these items
12 create a cost that must be recovered through
13 utility rates. In addition, as capitalization
14 supports all assets, it must be reduced for
15 assets that are not part of utility operations.
16 Assets that are not part of utility operations,
17 for which capitalization must be reduced,
18 include assets such as temporary cash
19 investments, non-utility property, internal
20 reserves, and goodwill. In other words, for
21 purposes of the EB/CAP adjustment,
22 capitalization could include more items than the
23 term would usually imply when used generally to
24 describe the utility's capital structure.

Q. Generally, why does a utility's rate base not equal its capitalization?

A. The causes of the EB/Cap differential vary at each company, but are generally variations in cash flow items not in rate base such as non-interest bearing liabilities that support utility's assets resulting from actual timing of payments on accounts payable, sales, and other taxes payable. Another cause of the EB/Cap differential may be imperfections in the estimation of cash working capital funding requirements.

Q. Is a utility's rate base supported entirely by Capitalization items such as: Common Capital Stock, Preferred Stock, Retained Earnings, Long Term Debit, and Short Term debt, also known as cost bearing capital?

A. No. Utilities do not pay a return, and have no capital cost associated with, accounts or taxes payable. Also, utilities provide cost free capital or uses of funds to ratepayers. For example, utilities do not receive a return on current customer accounts receivable for utility service. The net amount of these short-term

1 cost-free capital requirements is usually
2 referred to as working capital, which is
3 included in the utility's rate base.
4 Q. What is Distribution's rate year forecast of the
5 EB/CAP adjustment?
6 A. The Company calculated an EB/CAP adjustment of
7 $9.366 million which increases rate base.
8 Q. How did the Company calculate its EB/CAP
9 adjustment?
10 A. Distribution is part of a company that is
11 regulated by two different jurisdictions; the
12 New York State Public Service Commission, and
13 the Pennsylvania Public Utilities Commission.
14 Because of the two different jurisdictions, the
15 Company first took the New York Earnings Base
16 ($643.923 million) as a percentage of total
17 National Fuel Gas Corporation (or the Parent)
18 earnings base ($866.880 million), or 74.28%.
19 The Company then multiplied the 74.28%, by the
20 Parent's total capitalization to arrive at a New
21 York capital level of $653.289 million.
22 Q. How did the Company address the EB/CAP
23 adjustment in its last rate case, Case 07-G-
24 0141?

A. Based on the Company's response to DPS-94 , Attachment 2 (Exhibit___(SAP-2)), it indicates per the direct testimony of Regina Truitt in the last rate case at pages 38-39 "I recommended that the items specifically created by NY decisions and can be attributed solely to the New York Division, should be 100% to Distribution with the remaining capitalization allocated based on NY decisions portion of the Total earnings base. Again in order to reduce controversy in this proceeding I have not recommended a specific New York Division calculation, even though it would provide a more accurate allocation of capitalization to the NY division."

Q. Did Staff initially agree with the methodology?

A. Yes.

Q. How was the EB/CAP adjustment addressed in the rate case extension in Case 13-G-0136?

A. In Case 13-G-0136, the Staff Temporary Rate Panel states at page 43: "In this temporary rates proceeding, we did not have time to undertake an in depth review the EB/Cap calculations and evaluate the reasonableness of

1 the Company's averaging proposal. A detailed
2 review of the EB/Cap is necessary, and is more
3 appropriate for a permanent rates proceeding."
4 Q. Did the Company present the EB/Cap adjustment
5 differently in Case 13-G-0136 than they
6 typically have in the past?
7 A. Yes. The Company used a two year average in its
8 EB/CAP adjustment because the Company indicated
9 the EB/CAP adjustment has varied widely since
10 rates were last set in the 2007 Rate Order.
11 Q. Do you agree with the Company's EB/CAP
12 calculation in the current rate case filing?
13 A. Partially.
14 Q. Please explain.
15 A. We do not agree with the methodology of
16 allocating items that can be directly tied to
17 the New York Division. The Company's response
18 to DPS-146 (Exhibit___(SAP-2)) states, "There is
19 a handful of specific NY only capital elements
20 that are associated with specific regulatory
21 activity of each jurisdiction." These items are
22 Refund Pool, Gas Supplier Case Refunds,
23 Over/Under Collection of Gas Costs, Internal
24 Pension Reserve, Internal OPEB Reserve,

1 Provision for Refund, and Cap/Rel/OSS/SC11 85%.
2 When applying an allocation factor to these
3 items, it reflects an inaccurate level of
4 capital for both NY and PA. For example,
5 currently the amounts associated with the NY
6 identifiable items discussed above net to a
7 debit, reducing the NY capital balance. When
8 these NY specific items net as a debit, and are
9 then allocated, it affects NY ratepayers,
10 because the NY capital is not reduced by the
11 full amount. It also affects PA ratepayers, as
12 it will reduce the PA capital. In addition, if
13 the items discussed above net to a credit, it
14 affects NY ratepayers, because the NY capital is
15 not being increased by the full amount. It also
16 affects PA ratepayers, as it will increase the
17 PA capital. We do not believe NY, or PA rate
18 payers should be subject to advantageous, or
19 disadvantageous capital levels, when these items
20 can be explicitly identified between the two
21 jurisdictions. Our alternative EB/CAP proposal
22 is outlined below.
23 Q. Did the Company quantify the components
24 discussed above separately for NY, and PA?

1 A. Yes. The Company provided a "NY Only" column
2 reflected on page 3 of Exhibit___(DNK-1).
3 However, in response to DPS-146 (Exhibit___(SAP-
4 2)), the Company states "The far right column
5 labeled "NY Only" on Page 3 of Exhibit___(DNK-1)
6 was incorrectly inserted into the exhibit and
7 does not accurately reflect the New York
8 Division's allocation of capitalization as
9 established by the Commission in previous rate
10 cases…" The updated amounts allocated to NY and
11 PA were identified and provided in response DPS-
12 189, Attachment 1 (Exhibit___(SAP-2)).
13 Q. Do you agree with the Company's allocation
14 methodology for the remaining items?
15 A. Yes. For the remaining items it is necessary to
16 calculate the New York earnings base as a
17 percentage of the Parent's total earnings base
18 so the remaining capital can be allocated to the
19 two jurisdictions. It is impossible to track
20 the flow of monies to a specific division or
21 jurisdiction when capital items cannot be
22 explicitly identified as 100% NY, or 100% PA.
23 Q. Please explain your EB/CAP proposal.
24 A. We propose that New York items that can be

specifically identified be allocated 100% to the New York Division. These New York items would then be added to the remaining items that have been allocated by the percentage of New York Earnings base to Total Earnings base. In addition, the EB/CAP calculation should be consistent going forward, utilizing our proposed calculation in future rate proceedings.

Q. Please quantify the impact of your proposed calculation.

A. Our proposed methodology and calculation will reduce the Company's capitalization of $653.923 million by $4.469 million, to $648.320 million. This adjustment reduces the Company's EB/CAP adjustment that is presented in rate year rate base, by the same amount. The Company's adjustment of $9.366 million is reduced to $4.897 million. The panel's calculation of the adjustment is presented in Exhibit __ (SAP-3).

Q. Does this complete your testimony at this time?

A. Yes.

A.L.J. LECAKES: And the Accounting Panel's exhibits?

MR. FAVREAU: There were four exhibits Your Honor, SAP1 through 4. We ask that they be marked for identification. I would also like to note that SAP1 is also a corrected exhibit.

A.L.J. LECAKES: Okay. Yeah, and I -- I will take care of that on the exhibit disk, but for purposes the SAP1 will be marked as Exhibit 129 and that will be the corrected version and SAP2 will be marked as Exhibit 130, SAP3 131, and SAP4 as 132. Next witness or panel?

MR. FAVREAU: Our final witness or panel is the Staff Finance Panel. They filed -- I mean they -- they're presenting 99 pages of pre-filed direct testimony consisting of questions and answers and we would ask that this testimony be incorporated into the record as if given orally today.

A.L.J. LECAKES: I'm looking at the -- the CD that was given to me and it has Staff Finance Panel Updated Testimony as -- as the file name.

MR. FAVREAU: Right. That was the testimony that was -- that was presented to all the parties previous -- previous to the hearing.

A.L.J. LECAKES: That --.

MR. FAVREAU: So that is testimony that has been corrected essentially.

A.L.J. LECAKES: Okay. Okay. So at this point in the record the Staff Finance Panel Update Testimony should appear and also the file 16-G-0257 Staff FP Supplemental Testimony should appear immediately thereafter.

MR. FAVREAU: And the supplemental testimony consists of 6 pages of questions and answers, Your Honor.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

National Fuel Gas Distribution Corp.

Case 16-G-0257

September 2016

Prepared Testimony of:

Staff Finance Panel

Michael J. Augstell
Principal Utility Financial Analyst
Office of Accounting, Audits and Finance

Vincent Califano
Senior Utility Financial Analyst
Office of Accounting, Audits and Finance

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

Q. Please state your names and business address.

A. Our names are Michael Augstell and Vincent Califano. We are employed by the New York State Department of Public Service (Department). Our business address is Three Empire State Plaza, Albany, New York 12223.

Q. Mr. Augstell, what is your position at the Department?

A. I am employed as a Principal Utility Financial Analyst in the Office of Accounting, Audits and Finance.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Arts Degree in Economics from the University of Rochester in 1992. After graduating I worked in commercial loan banking and thereafter as a financial analyst for General Electric Power Systems. In the five years prior to joining the Department I was employed at UHY Advisors NY, Inc. (UHY) in Albany, New York. I worked in the Valuation and Litigation Services department at UHY, conducting business valuations, financial analysis and forensic accounting, and class

1 action claims administration. I joined the
2 Department in December 2006.
3 Q. Mr. Augstell, please briefly describe your
4 current responsibilities with the Department.
5 A. I work on assignments that involve analyzing the
6 financial condition, financing mechanisms, risk,
7 cost of debt, cost of equity, diversification,
8 and relative business positions of utilities and
9 their holding company parent. Assignments
10 involve rate cases, financing proposals and
11 special projects.
12 Q. Have you previously testified in a regulatory
13 proceeding before the New York State Public
14 Service Commission (Commission)?
15 A. Yes. I provided testimony to the Commission
16 regarding the appropriate capital structure and
17 cost of capital for the subject utilities in
18 Case 07-E-0523 (Consolidated Edison Company of
19 New York, Inc. - Electric Rates), Case 07-E-0949
20 (Orange and Rockland Utilities, Inc. - Electric
21 Rates), Case 07-S-1315 (Consolidated Edison
22 Company of New York, Inc. - Steam), Case 08-G-
23 1398 (Orange and Rockland Utilities, Inc. - Gas
24 Rates), Case 09-W-0731 (United Water New York,

Inc. – Water Rates), Case 09-W-0824 (United Water New Rochelle, Inc. – Water Rates), Case 10-E-0362 (Orange and Rockland Utilities, Inc. – Electric Rates), Case 11-G-0280 (Corning Natural Gas Corporation – Gas Rates), Case 12-M-0192 (Fortis Inc. and CH Energy Group – Merger) and Case 14-W-0006 (United Water Westchester Inc. and United Water New Rochelle Inc. – Merger).

Q. Mr. Califano, what is your position at the Department?

A. I am employed as a Senior Utility Financial Analyst in the Office of Accounting, Audits and Finance.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Business Administration with a focus in Finance from the University at Albany in 1994. In addition, I recently completed 24 hours in college accounting credits in order to supplement my accounting and auditing work experience. I joined the Department in June of 2015. Prior to joining the Department, I worked at the New York State Department of Taxation and

1 Finance in various positions from January of
2 2012 to June of 2015. My duties with the New
3 York State Department of Taxation and Finance
4 included supervising a team of tax resolvers,
5 auditing high value tax returns, advising
6 taxpayers regarding estate, fiduciary,
7 miscellaneous, partnership, real estate and
8 personal income tax regulations. Prior to that,
9 I was employed at Page One (Financial) as an
10 accounts manager. My work duties at Page One
11 included creating new client portfolios,
12 communicating with outside brokers, creating
13 investment reports and managing IRA's, mutual
14 funds and other investments.
15 Q. Please briefly describe your current
16 responsibilities with the Department.
17 A. My work assignments include analyzing the cost
18 of debt, cost of equity, capital structure,
19 financial mechanisms, risks, and the competitive
20 position of electric and gas utilities and their
21 parent company.
22 Q. Have you previously testified before the
23 Commission?
24 A. Yes, I recently testified in the St. Lawrence

1 Gas Company, Inc., Case 15-G-0382.
2 Q. Have you been involved in any other regulatory
3 proceedings?
4 A. Yes, I have provided rate of return analysis for
5 gas pipeline proceedings before the Federal
6 Energy Regulatory Commission (FERC). These
7 proceedings typically involve a coalition of
8 northeastern states who have similar interests
9 in establishing a fair rate of return on natural
10 gas pipelines. Most recently, I have worked on
11 FERC proceedings for the Empire Pipeline and the
12 Iroquois Pipeline.
13 **PURPOSE OF TESTIMONY**
14 Q. What is the purpose of your testimony in this
15 proceeding?
16 A. The purpose of our testimony is to establish the
17 fair rate of return (ROR) that will be used to
18 determine the revenue requirement for National
19 Fuel Gas Distribution Corporation (Distribution
20 or the Company) for the rate year ending March
21 31, 2018. Estimating the ROR requires an
22 estimation of the proper capital structure and
23 the cost rates of the individual cost components
24 used to finance the Company's earnings base.

1 Our testimony will also respond to issues raised
2 in the testimonies of Company witnesses Bulkley
3 and Smith. Lastly, we will explain why our
4 recommended rate of return provides the Company
5 with continued access to reasonably-priced
6 capital.
7 Q. Does your testimony rely on interrogatory
8 responses (IRs) provided by the Company?
9 A. Yes. These IRs are included as Exhibit__(FP-1).
10 Q. Are you sponsoring other exhibits?
11 A. Yes. We are sponsoring 22 exhibits, identified
12 as Exhibit__(FP-1) through Exhibit__(FP-22).
13 **SUMMARY**
14 Q. Please summarize your testimony and how it
15 varies from the Company's request.
16 A. We recommend an overall after-tax rate of return
17 of 6.86%, as opposed to the Company's request of
18 a 7.81% overall after-tax return. On a pre-tax
19 basis, our recommended overall rate of return is
20 9.21% compared to the Company's request of
21 10.97%. Our pro forma cost of capital can be
22 seen in Exhibit___(FP-2). The difference is
23 primarily due to our use of an 8.6% return on
24 equity (ROE) and a 42.3% equity ratio as opposed

1 to the Company's use of a 10.2% ROE and 48.0%
2 equity ratio.
3 Q. What is the revenue requirement impact of your
4 adjustments to the Company's requested rate of
5 return?
6 A. In terms of revenue requirement, the difference
7 in the pre-tax ROR between Department staff
8 (Staff) and the Company is approximately $13.2
9 million. We used a cost of debt rate of 5.62%,
10 compared to the 5.64% rate used by the Company.
11 Our ROE recommendation was determined using two
12 different equity-costing methods, each weighted
13 consistent with how the Commission has weighted
14 them in prior litigated cases. We also
15 recommend the use of a different capital
16 structure than the Company filed. We recommend
17 the Commission use the respective long-term debt
18 and common equity ratios of the Company's
19 parent, National Fuel Gas Company (Parent). By
20 doing this we will properly reflect the
21 anticipated mix of capital during the rate year
22 and be confident that the proportion of common
23 equity attributed to Distribution is no more
24 than the common equity supporting the Parent's

1 riskier non-regulated operations. Lastly, we
2 will explain why our recommended rate of return
3 provides the Company continued access to
4 reasonably-priced capital.
5 **FAIR RATE OF RETURN DISCUSSION**
6 Q. What is a fair rate of return for a regulated
7 utility?
8 A. A utility's overall rate of return represents
9 the cost of capital used to finance the assets
10 that are providing regulated utility service to
11 customers. The estimation of a utility's rate
12 of return requires an estimate of the company's
13 capital structure and the cost rates of the
14 various forms of capital financing the utility's
15 assets. The ratemaking process should provide a
16 utility with a reasonable opportunity to earn a
17 return on utility investments equivalent to the
18 return available on investments of similar risk.
19 It is the utility management's ultimate
20 responsibility to operate the company in a
21 manner that allows it to actually earn the
22 allowed return for its investors.
23 Q. How is a fair rate of return calculated?
24 A. Generally, in New York State, the fair rate of

return for a utility company is calculated through a weighted average cost of capital (WACC), which is typically comprised of common equity, customer deposits, preferred stock and long-term debt. Calculating the proper cost components involves forecasting and reconciling a company's sources of capital with their individual requirements. Long-term debt and common equity are the two primary sources of capital, while customer deposits typically are a small portion of the total capital. While preferred stock is not as commonly used now as it has been in the past, it is still sometimes utilized as another source of capital.

Q. How are the cost rates determined for each of the individual components?

A. The method for estimating the current cost of long-term debt is generally established in the financing agreements between a company and its lending institutions. In return for lending money to a company, debt holders receive earnings in the form of contractual payments of interest and principal. The analyst then must forecast the amounts, timing and terms of

forecasted debt issuances during the rate year to estimate the weighted average rate year cost of debt. Customer deposits have a prescribed cost rate that is set annually by the Commission. The current customer deposit cost rate is .85%. While the Parent has the authority to issue shares of preferred stock, it has not elected to do so. Since the Parent has not issued preferred stock, there is no cost rate for preferred stock. The expected return requirements of a utility's common equity investors can only be gleaned through a cost of equity analysis. Generally, methodologies such as the Discounted Cash Flow (DCF) and the Capital Asset Pricing Model (CAPM) are employed to estimate the return required by equity investors.

CAPITAL STRUCTURE

Q. What is Distribution's projected rate year capital structure for its gas operations?

A. In Company witness Ruth Friedrich-Alf's Exhibit___(RMFA-1), Page 10, Distribution uses a hypothetical capital structure with a common equity ratio of 48.0%, a long-term debt ratio of

51.6% and a customer deposit ratio of 0.40%.

Q. What do you mean by a hypothetical capital structure?

A. A hypothetical capital structure refers to imputing, for ratemaking purposes, a capital structure that differs from the capital structure reported on a utility's financial statements.

Q. What is the capital structure for Distribution?

A. As shown on Exhibit__(FP-3), at December 31, 2015 the Company capital structure consisted of a common equity ratio of 63.0% and a long-term debt ratio of 37.0%.

Q. In testimony, did the Company witnesses discuss why they believe that a hypothetical capitalization is appropriate?

A. There is no specific testimony supporting the requested 48.0% equity ratio. However, on pages five through six in her testimony, Company witness Bulkley discusses the reasonableness of a 48.0% common equity ratio by stating, "…the Company's requested equity ratio of 48 percent is at the low end of the range of the authorized ratemaking equity ratios and actual equity

ratios of the companies in my proxy groups. Therefore, I conclude the Company's Distribution's requested equity ratio is conservative."

Q. Do you find that a 48.0% common equity ratio is on the low end of the range of the authorized ratemaking common equity ratios in Company witness Bulkley's proxy groups?

A. No. Company witness Bulkley used a Combined Utility proxy group and a Natural Gas proxy group (Proxy Groups). She reviewed the common equity ratio averages of the holding companies in her Proxy Groups, the authorized capital structures of the operating companies in her Proxy Groups and the actual common equity ratios of the operating companies in her Proxy Groups.

Q. What was the common equity ratio average for the companies in her Proxy Groups?

A. On page 87 of her testimony Company witness Bulkley states that, "I have reviewed the authorized capital structures of the regulated utility operating companies in the Combined Utility and Natural Gas Proxy Groups for the period from 2011 through 2014. As shown on

Exhibits__(AEB-13) and __(AEB-14), the mean annual equity ratio of the proxy companies over that period was 54.02 percent for the Combined Utility Group and 56.27 percent for the Natural Gas Proxy Group."

Q. Are these averages a good basis in determining a common equity ratio for a regulated utility?

A. No. While she states she reviewed the "authorized capital structures of the regulated utility operating," the percentages on Exhibits ___(AEB-13) and ___(AEB-14) are actually for the holding companies of the regulated utilities, and the majority of these holding companies also have investments in riskier, non-regulated ventures. Because of the competitive nature of the non-regulated ventures, holding companies with substantial non-regulated investments would be expected to have higher levels of common equity relative to investments in only regulated utilities. Our capital structure recommendation is for a regulated utility business, not a holding company.

Q. Please describe holding company structures and the Parent's company structure.

A. A utility holding company reports its overall capital structure as part of its consolidated balance sheet in various reports to the Securities and Exchange Commission (SEC) as well as in its Annual and Quarterly Reports to Shareholders. The consolidated balance sheet reflects the financial position of all of the holding company's operations. A holding company like National Fuel Gas Company has many subsidiaries, and it contains many individual financial statements for major subsidiaries, of which Distribution is but one part. Importantly, Distribution does not issue its own common equity or its own long-term debt; it only receives capital from the Parent in the form of "Advances from Associated Companies". Distribution is a wholly-owned subsidiary of National Fuel Gas Company. The Parent is a diversified energy corporation whose elevated risk profile is such that its credit ratings are not subject to the relatively generous regulated utility framework that nearly all utility holding companies are. In 2015, National Fuel Gas Company reported sales of $1.76 billion, a

loss of $380 million and total assets of $6.7 billion. The Parent trades on the New York Stock Exchange with the symbol, NFG.

Q. What are the major reportable business segments of the Parent?

A. The Parent has five reportable business segments that include: 1) Exploration and Production; 2) Pipeline and Storage; 3) Gathering; 4) Utility; and, 5) Energy Marketing.

Q. What is the most recent reported common equity ratio for the Parent?

A. The Parent's common equity ratio per the June 30, 2016 quarterly report filed with the SEC was 42.3%, shown on Exhibit___(FP-3).

Q. Company witness Bulkley next shows that the average book common equity ratios for her Proxy Groups operating companies are greater than 48.0%. Explain why using an average subsidiary common equity ratio is not reasonable to use in Distribution's capitalization?

A. The capital structures for utility subsidiaries of holding companies may not reflect either rational capitalization policies, or actual common equity employed, and therefore may not be

suitable for establishing a utility's rate of return. The subsidiary common equity balance may not, in fact, be financed by common equity at the holding company level. Rather, some of the utility common equity balance may instead be proceeds from debt issued at the holding company level and classified on the utility subsidiary's books as common equity at the time the proceeds were invested in the utility subsidiary. In addition, the use of a subsidiary capital structure is not appropriate for setting a utility's rates in cases where a holding company parent has financed riskier competitive non-utility operations with less equity (and hence more debt) than would be required for these ventures to achieve the same credit rating as the utility subsidiaries. Unless the utility subsidiary's credit rating is insulated from these risks, using the subsidiary capital structure would effectively require ratepayers of a lower-risk natural gas distribution company to subsidize its parent's riskier investments. Finally, it is not in customers' interests to pay for equity ratios that are higher than the

equity ratio of the parent company. Absent suitable ring-fencing, rating agencies in whole and in part, base their utility ratings on the parent company's capital structure. Under these circumstances, there is no reason to pay for additional equity because it will not enable the utility to achieve a higher credit rating and realize lower borrowing costs.

Q. Does it appear that the lower-risk natural gas Distribution is subsidizing the Parent's riskier investments?

A. Yes, because the utility is not insulated from these risks, the lower-risk natural gas regulated utility appears to be subsidizing the Parent's riskier investments. It is unreasonable to expect ratepayers of New York to support the disparity in the risks of the Parent's other activities and it illuminates the inconsistency of the Parent's financial policies. While Distribution professes the importance of a strong financial profile when putting forth positions to the Commission, the ultimate parent has significant leverage from its other, riskier businesses.

Q. Company witness Bulkley lastly shows that the average common equity ratio recently allowed is 51.01% for her Combined Utility Proxy Group and 52.42% for her Natural Gas Proxy Group. Are these average ratios appropriate to use in Distribution's capitalization?

A. No. In other states, rate plans are often not based on fully forecasted test years, like in New York. This means that rates are set based on historical costs, with no recognition of cost escalations. In a survey prepared for the Edison Electric Institute in January 2013, Alternative Regulation for Emerging Utility Challenges: An Updated Survey (Exhibit___(FP-4), it is stated that 15 U.S. jurisdictions use fully-forecasted forward test years, three states use partially-forecasted test years, 14 use transitional/varying test years and 20 use historical test years. In other states, fuel costs are not always completely and quickly passed through to customers. Pension and other post-employment benefits are not always trued-up, regardless of a large drop in the stock market and the resulting large impact on pension

plan assets. We are not recommending a common equity ratio for Distribution that exceeds the consolidated common equity ratio for the Parent, and are actually conservative in our recommendation of a 42.3% common equity ratio, given that the Parent's riskier non-utility businesses should be capitalized with a thicker layer of common equity than the utility to offset their significantly higher business risk. Had we elected to perform such an adjustment our recommended common equity ratio would be considerably lower.

Q. How much of Distribution's revenues are subject to deferrals and true-ups?

A. Using the response to Staff IR DPS-50, contained in Exhibit__(FP-1), and including purchased gas costs, approximately 73% of the revenues for Distribution are subject to either deferrals or true-ups that include gas adjustment costs, purchased gas costs, a Revenue Decoupling Mechanism (RDM) and pension and other post-employment benefits (OPEB). With only 27% of Distribution's revenues subject to uncertainty for the rate year ending March 31, 2018, there

1 is a significant reduction in the risk to either
2 a one-year or a multi-year rate plan.
3 Q. How do credit agencies assess the level of risks
4 for a utility?
5 A. Credit rating agencies like Moody's and S&P
6 assess the level of business risk and financial
7 risk of a company when assigning or reviewing
8 credit ratings. They then assign a credit
9 rating or ratings based upon their overall
10 assessment of a given company's business and
11 financial risk.
12 Q. What comprises risk for a company?
13 A. Risk for a company is comprised of business risk
14 and financial risk. Business risk is basically
15 the risk that a company may not be able to
16 receive enough cash flow to cover operating
17 expenses. Competition, industry risk and
18 country risk are all types of business risk.
19 Financial risk is tied to the level of debt a
20 company has taken on to finance its operations.
21 Financial risk increases with the amount of debt
22 a company assumes to finance operations. If a
23 firm is financed with all equity, than there is
24 no financial risk.

Q. Describe what Moody's and S&P consider in evaluations of utility risk.

A. The rating agencies combine an analysis of a company's business risk profile with a financial risk analysis to determine a credit rating.

Q. What credit ratings are assigned by Moody's and S&P to Distribution and the Parent?

A. The Parent's S&P and Moody's ratings are "BBB" and "Baa3", respectively. The S&P rating is two notches above investment grade, and the Moody's rating is one notch above investment grade. Since the Parent issues long-term debt to address the debt financing requirements of all of its business segments including Distribution, the credit rating agencies do not ascribe credit ratings to Distribution nor any of the other business segments.

Q. Summarize S&P's assessment of a utility's business and financial risk profiles.

A. S&P assesses the relative strength of a company's business risk position and assigns it one of six business risk profiles ranging from least risk to most risk with the lowest business risk profile ranked "Excellent" to those with

1 the highest risk business profiles labeled
2 "Vulnerable." S&P determines financial risk by
3 categorizing a utility within six risk profiles
4 from "Minimal" for companies with little or no
5 debt to "Highly Leveraged" for companies with
6 high levels of debt.
7 Q. What is the business risk profile that S&P
8 ascribes to Distribution?
9 A. In S&P's most recent Summary Analysis of
10 National Fuel Gas Company, the business risk
11 profile was not specifically mentioned. In
12 S&P's March 27, 2013 Summary Analysis, the
13 business profile for Distribution was described
14 as "Excellent." As the Parent's rating has not
15 changed since this 2013 report, and since the
16 operating characteristics of Distribution have
17 not changed in any meaningful way since that
18 time, we have every reason to believe that the
19 business risk profile for Distribution remains
20 "Excellent".
21 Q. How does S&P assess the financial risk of a
22 utility?
23 A. As illustrated in S&P's reports, "Key Credit
24 Factors For The Regulated Utilities Industry",

Exhibit__(FP-5), and "Methodology: Business Risk/Financial Risk Matrix Expanded," Exhibit___(FP-23), S&P looks at three financial ratios. These are: Funds From Operations (FFO)/Debt; Debt/(Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA); and, Debt/Capital.

Q. What are these financial ratios for Distribution?

A. We calculated these ratios using Staff's recommended adjustments, including our recommended equity ratio and ROE, for the rate year ending March 31, 2018. As shown on Exhibit___(FP-6), the ratios using the Staff's recommended adjustments are: FFO/Debt (18.8%), Debt/EBITDA (3.9), and Debt/Capital (57.7%).

Q. What does this analysis imply for an S&P rating for Distribution?

A. Using the S&P financial matrix shown on Exhibit___(FP-6), the three financial risk ratios for Distribution would be between "Significant" and "Aggressive." Combining this with an "Excellent" business risk implies an approximate S&P rating above "BBB."

Q. How does Moody's assess the business and financial risk of a utility?

A. As illustrated in Moody's report, Exhibit__(FP-7), "Regulated Electric and Gas Utilities," published December 23, 2013, Moody's uses a rating grid incorporating four rating factors in assigning a credit rating: (1) Regulatory Framework-25%; (2) Ability to Recover Costs and Earn Returns-25%; (3) Diversification-10%; and, (4) Financial Strength, Key Financial Metrics-40%.

Q. What are the metrics that Moody's uses in determining the credit rating for a utility?

A. They are: (Cash Flow from Operations (CFO) pre-Working Capital (WC) + Interest)/Interest; CFO pre-WC/Debt; (CFO pre-WC-Dividends/Debt); and, Debt/Capitalization.

Q. What are Distribution's ratios for Moody's four rating factors?

A. As with the S&P metrics, we calculated these ratios using Staff's recommended adjustments including our recommended equity ratio and ROE recommendation. As shown on Exhibit___(FP-6), the ratios with Staff's recommended adjustments

are: (CFO pre-WC + Interest)/Interest (4.4x); CFO pre-WC/Debt (24.3%); (CFO pre-WC-Dividends)/Debt (8.7%); and, Debt/Capitalization (57.7%).

Q. What do the financial metric results imply for a Moody's rating?

A. Using the Moody's financial matrix shown on Exhibit___(FP-6), the four financial risk ratios for Distribution would be above a "Baa" rating.

Q. Has Moody's had any comments on a probable rating for Distribution in recent reports?

A. Yes, in Moody's February 26, 2016 report, "National Fuel Gas Company, Update following the February 2016 downgrade," Exhibit___(FP-8), it is stated that the Exploration and Production (E&P) business on a standalone basis would be comparable to a low "Ba" rating, the midstream business (gathering, interstate pipeline and storage) pipeline and storage) would be comparable to a high "Ba" to a low "Baa" rated company and the natural gas utility could independently support a low "A" rating given the regulatory regime in its service area and its conservative capitalization.

NATIONAL FUEL GAS COMPANY IMPAIRMENTS

Q. The Moody's report referenced above mentions a downgrade. What does this refer to?

A. In a February 18, 2016 report, Moody's downgraded National Fuel Gas Company from "Baa2" to "Baa3," citing weaker cash flows from the E&P segment, slower anticipated growth in midstream volumes, and an expected increase in leverage through 2017. This research report is shown on Exhibit__(FP-9).

Q. Please elaborate why the Exploration and Production segment is experiencing weaker cash flows.

A. As we previously mentioned, the Parent has five reportable segments or "divisions," comprising both regulated and non-regulated businesses. The rates of the Pipeline and Storage segments are regulated by FERC, and the Utility segment is regulated by the Commission and the Pennsylvania Public Utility Commission.. The remaining divisions, E&P, Gathering and Energy Marketing are non-regulated. For 2015, approximately 50% of earnings before interest, taxes, depreciation and amortization (EBITDA)

1 was from the Pipeline and Storage and Utility
2 segments, while the remaining 50% of EBITDA was
3 from the other businesses. Due to significant
4 declines in oil and gas commodity prices, the
5 E&P oil and gas producing properties have been
6 required to write down these asset values on the
7 Parent's balance sheet. This action is commonly
8 referred to as an impairment.
9 Q. What are the financial consequences of
10 impairments to a company's finances?
11 A. Basically, an impairment of a fixed asset occurs
12 when there is a significant decrease of the fair
13 value of the asset, and the business has to
14 decrease the asset value on the balance sheet.
15 This loss in value is then recognized as a loss
16 on the company's income statement. Essentially,
17 the precipitous drop in the market prices of
18 both oil and natural gas have greatly diminished
19 the value of the Parent's oil and natural gas
20 reserves, which has triggered asset write downs
21 per SEC rules. SEC rules require that the
22 Parent perform a ceiling test calculation each
23 quarter on the oil and natural gas properties.
24 In each instance where the capitalized costs of

1 the oil and gas properties have exceeded the
2 ceiling, less accumulated depletion and related
3 deferred taxes, the Parent has had to write down
4 the value of these assets, which is an
5 impairment. Recording an impairment of a fixed
6 asset requires the reduction in value of the
7 asset on the balance sheet and the recognition
8 of a loss in the income statement.
9 Q. How have oil and gas prices declined?
10 A. West Texas Intermediate (WTI) crude oil prices
11 went from over $100 per barrel in July 2014, to
12 under $30 per barrel in February 2016, and the
13 Henry Hub Natural Gas spot price went from $4.00
14 per million Btu in July 2014 to $2.00 per
15 million Btu in March 2016.
16 Q. What has been the magnitude of impairments to
17 date?
18 A. The impairments have totaled approximately $2.0
19 billion for the past six quarters. The
20 impairments started in early 2015 and
21 contributed to the Parent's loss of $380 million
22 in 2015, compared to income of $300 million in
23 2014. These impairments have continued in each
24 successive quarter, which has directly

contributed to a decline in the Parent's common equity ratio from 61.2% at March 31, 2015 to 42.3% at June 30, 2016 as shown in Exhibit___(FP-3).

Q. Does National Fuel Gas Company expect to record an impairment in the next quarter?

A. Yes, per the June 30, 2016 quarterly report, the Parent expects an additional impairment charge for the quarter ending September 30, 2016.

Q. In addition to the diminishing common equity layer on the Parent's balance sheet, have these impairments had other negative impacts on the Parent and Distribution?

A. Yes. Because of these impairments, the Parent's existing 1974 indenture covenants have precluded it from issuing incremental long-term debt through September 2016, and the Parent expects that its inability to do so will likely continue through the second half of fiscal 2017 as mentioned in the Parent's quarterly report (10-Q) for the period ending June 30, 2016.

Q. Given the restrictions placed on it by the indenture, how is the Parent addressing its liquidity?

A. While the Parent cannot issue new long-term debt, it does have a $750 million revolving credit facility through December 5, 2019 and a $500 million 364-day revolving credit facility through September 29, 2016. In addition, the Parent has a $500 million commercial paper program. At June 30, 2016 there were no outstanding balances of either notes payable to banks or commercial paper.

Q. How does Distribution currently raise debt?

A. The Parent and Distribution have a credit agreement where Distribution issues notes to the Parent as needs for funds arise. The terms of these notes mirror the public issuances of debt made by the Parent in order to raise capital for Distribution. With this arrangement, the cost of Distribution's debt mirrors that of the Parent. While Distribution currently has the authority to issue up to $100 million in promissory notes through December 2017, pursuant to the Commission's Order in Case 14-G-0228, Distribution has not issued any promissory notes since 2009.

Q. Are there any mechanisms in place that insulate

1 Distribution's assets from the risks of the
2 Parent's other businesses, including the E&P
3 segment?
4 A. Distribution's current protections are minimal
5 at best. According to the response to Staff IR
6 181, included in Exhibit___(FP-1), the Parent
7 has some protections that include a System Money
8 Pool where the Parent coordinates the short-term
9 debt capital needed by the eligible borrowers of
10 the Parent, which includes Distribution.
11 Distribution is only permitted to borrow from
12 the fund and may not lend to it. In addition,
13 Distribution maintains separate bank accounts.
14 Q. What are these types of mechanisms called?
15 A. Mechanisms that protect utility assets from any
16 ill effects of the riskier competitive
17 operations within a holding company structure
18 are colloquially referred to as "ring-fencing".
19 Ring-fencing is defined as legally separating
20 assets, or liabilities, in a subsidiary to
21 protect them from creditors and in the context
22 of regulated utilities, is intended to insulate
23 assets in the utility subsidiary from the risks
24 of the holding company. In theory, if a

1 subsidiary is ring-fenced, and if the holding
2 company or another subsidiary goes bankrupt,
3 creditors cannot attach their claims to the
4 assets of the ring-fenced subsidiary, and vice
5 versa. In addition, a fully ring-fenced company
6 should be insulated from its parent's influence
7 regarding the financial decisions of the
8 subsidiary. Also, ring-fencing may allow a
9 subsidiary to have a higher credit rating than
10 its parent.
11 Q. Do you believe that more stringent ring-fencing
12 provisions need to be implemented?
13 A. Yes. As discussed earlier in our testimony,
14 about 50% of consolidated EBITDA in 2015 was
15 from non-regulated businesses and the largest
16 segment, exploration and production, has had
17 approximately $2 billion in impairments for the
18 oil and gas properties, and more impairments are
19 expected in the next quarter. Because of the
20 significant amount of impairments to date
21 emanating from the Parent's Exploration and
22 Production segment, National Fuel Gas Company is
23 currently unable to issue new long-term debt due
24 to certain debt covenant restrictions. Since

1 Distribution does not issue its own debt, it too
2 is currently unable to access new debt capital.
3 In addition, there is the possibility that the
4 Parent could lose its investment grade rating,
5 which could make it difficult for Distribution
6 to access reasonably-priced capital. Given
7 these serious concerns, we believe that it is
8 essential that additional, strong ring-fencing
9 provisions be instituted.
10 Q. Are there any debt issuances for the Parent
11 forecast during the rate year?
12 A. While there are no debt issuances for the Parent
13 forecast during the rate year, there are two
14 issuances planned of $300 million in April 2018,
15 and $250 million in April 2019. Both of these
16 have exceptionally high estimated debt cost
17 rates of 6.88%, per Distribution. This is an
18 example of why we are recommending ring-fencing
19 mechanisms. The Parent's credit ratings are
20 hovering near the very bottom of investment
21 grade, and because Distribution's assets are not
22 isolated from the parent, the Company may have
23 to pay higher debt costs than are necessary.
24 Because of their low business risk attributes,

most utilities are currently able to access debt at cost rates much lower than the rates projected by the Company. For instance, Brooklyn Union Gas Company issued $500 million of 10-year debt at 3.407% and $500 million of 30-year debt at 4.504% in March 2016; Consolidated Edison Company of New York issued $550 million of 30-year debt at 3.85% in June 2016; and Key Span Gas East Corporation issued $700 million of ten-year debt at 2.742% in August 2016. We find that Distribution's assets are not properly isolated from the Parent, and in order to provide ready access to debt at reasonable rates, we recommend that several ring-fencing mechanisms be implemented.

Q. Have the rating agencies commented on the risks of the Parent's other businesses?

A. Yes. S&P's February 24, 2016 Summary Analysis, Exhibit___(FP-10), states: "We believe the earnings and cash flow stability provided by NFG's regulated businesses provide a level of credit enhancement beyond that reflected in our initial analytical assessment, or anchor." This statement shows that the regulated businesses,

1 including Distribution, are contributing to a
2 higher credit rating for the Parent. S&P states
3 that the business risk of the E&P business is,
4 "…relatively weak because of its limited oil and
5 gas reserve scale, exposure to weal natural gas
6 prices, limited geographic diversification, and
7 the high capital intensity and exposure to
8 volatile commodity prices inherent in the E&P
9 industry."
10 Q. Do most of the other major utilities operating
11 in New York State have stronger ring-fencing
12 provisions in place than those currently
13 utilized by the Company and its Parent?
14 A. Yes. The majority of the major New York
15 operating companies have adopted what we
16 consider to be strong ring-fencing protections,
17 as they have generally been recognized as strong
18 by one or more of the rating agencies. In such
19 instances, this has enabled Staff to rely upon
20 the utility stand-alone capital structures in
21 rate cases, and has also resulted in numerous
22 ratemaking capitalizations with 48.0% common
23 equity ratios. In contrast to Distribution, all
24 of the other major utilities issue their own

1 debt and have separate credit ratings from their
2 respective parents. Distribution clearly needs
3 to have more protections in place to protect its
4 assets from the Parent's riskier operations.
5 The New York utilities' specific ring-fencing
6 mechanisms that are currently in place are shown
7 in detail in Exhibit___(FP-11).
8 Q. Do you recommend any new ring-fencing provisions
9 for the Commission to consider imposing in this
10 proceeding?
11 A. Yes. We recommend that Distribution be
12 prohibited from paying dividends to the Parent,
13 if its average common equity ratio for the
14 trailing 12 months prior to the dividend payment
15 is more than 200 basis points below the common
16 equity ratio used in setting rates. This will
17 help to maintain an adequate equity ratio for
18 Distribution.
19 Q. What has Distribution's common equity ratio been
20 recently?
21 A. For the past several years it has been around
22 60.0%, so compliance with this minimum common
23 equity ratio requirement should not be
24 difficult.

1 Q. What other ring-fencing mechanisms do you
2 recommend?
3 A. We recommend five additional provisions
4 including: 1) Distribution should be required to
5 issue its own long-term debt. This will
6 demonstrate that there is separation from the
7 Parent and that the true debt cost is supported
8 by the financial risk of Distribution. 2) The
9 Parent should pursue obtaining individual credit
10 ratings from Moody's and S&P for Distribution,
11 which in combination with all the following
12 ring-fencing mechanisms would insure that
13 Distribution is satisfactorily insulated from
14 the heightened risks of the Parent and its other
15 affiliates. 3) Should the Parent be downgraded
16 from either the current S&P, 'BBB', rating or
17 the Moody's 'Baa3' rating, we recommend that the
18 interest rate for Distribution in subsequent
19 rate filing to match that of Staff's proxy
20 group, "BBB+". This provision is not necessary
21 should Distribution obtain its own credit
22 rating. 4) The creation of a special class of
23 preferred stock by Distribution, to be held by a
24 trustee approved by the Commission, which shall

be referred to as the "golden share." The holder of the golden share would be independent of the Holding Company and its affiliates, and would prevent a bankruptcy of the parent, or any of its affiliates, from triggering a voluntary bankruptcy of Distribution. The holder of the golden share would exercise the voting right for the protection of the interests of New York ratepayers. Finally, 5) A non-consolidation letter, issued by the Holding Company's general counsel, should be filed to further demonstrate the implementation of ring-fencing provisions, which would demonstrate the legal and credit separation of Distribution from its parent and related affiliates.

Q. Have the rating agencies commented on utility ring-fencing mechanisms in reports?

A. Yes. Moody's December 23, 2013 "Rating Methodology for Electric and Gas Utilities," contained in Exhibit___(FP-6), states that, "The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate management and operations of the OpCo

(operating subsidiary) from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers."

Q. You are recommending the Parent's common equity ratio of 42.3% be used in the capitalization for Distribution. Would implementing your recommended ring-fencing mechanisms warrant consideration of a higher equity ratio recommendation?

A. Yes. If the Parent implements our recommended ring-fencing provisions, and they are recognized by S&P and Moody's, then we would view Distribution's assets as properly insulated from the Parent and a higher common equity ratio, perhaps one in the 48.0% range, should be considered in the next rate proceeding.

SUMMARY CAPITALIZATION

Q. Can you substantiate that your recommended capitalization ratios are consistent with Distribution's overall risk profile?

A. Yes. We find that our recommended capitalization and ROE results in financial ratios as used by Moody's and S&P in assessing a

1 regulated utility that will allow Distribution
2 to maintain its financial integrity.
3 Q. Does the Commission agree with the use of a
4 consolidated parent's capitalization?
5 A. Yes. It is a long-established policy of the
6 Commission to use the consolidated capital
7 structure when setting rates of an affiliated
8 utility company, and there are no compelling
9 reasons to deviate from this policy in this
10 case. For example, in Case 05-E-1222, New York
11 State Electric & Gas Corporation-Rates, Order
12 Adopting Recommended Decision with Modifications
13 (issued August 23, 2006), on pages 81-90, the
14 Commission reaffirmed its position on the use of
15 the consolidated capital structure, stating that
16 it would be willing to re-evaluate NYSEG's
17 capital structure, "…if and when Energy East
18 provides its criteria to fully insulate the
19 subsidiary's capital structure and financial
20 standing in a manner that the credit rating
21 agencies would recognize NYSEG's credit
22 worthiness separate and apart from energy
23 East's." Lacking strong evidence to the
24 contrary, the Commission has ruled that the

1 consolidated capitalization represents the true
2 capital costs and embodies the true financial
3 risks for all its subsidiaries.
4 Q. Explain your analysis in determining your
5 recommended capital structure.
6 A. We began by examining the Parent's financing
7 practices within its business segments. We also
8 reviewed S&P and Moody's analysis reports of the
9 Parent. S&P rates them as having a
10 'Satisfactory' business risk and 'Significant'
11 financial risk. There is significant financial
12 risk discussed in S&P's Parent report from
13 February 24, 2016, contained in Exhibit__FP-10).
14 S&P expects the Parent to outspend operating
15 cash flows over the next few years and
16 potentially funding shortfalls with debt and
17 credit measures are projected to remain weak.
18 While the Parent could raise capital by issuing
19 new shares of common equity, we are unaware of
20 public information that it intends to do so
21 anytime in the near-term. Also, the Parent pays
22 out approximately $130 million in dividends per
23 year and just recently increased the dividend on
24 common stock, which it has done for 46 straight

1 years. Additionally, the Parent has not
2 provided any evidence why Distribution should
3 have a higher equity ratio than that of National
4 Fuel Gas Company. Since the Parent's cost of
5 capital is premised on a 42.3% equity ratio, to
6 allow a rate higher than that for Distribution
7 would mean that ratepayers would be paying for
8 costs that are not actually being incurred by
9 the Company.
10 Q. Do you recommend that the Commission update the
11 capital structure at the time of its decision in
12 this rate case?
13 A. Yes. In order to best reflect the actual mix of
14 capital during the rate year, we recommend that
15 the capitalization ratios be updated to reflect
16 the Parent's common equity ratio for the most
17 recent financial statements available. The
18 common equity ratio may increase or further
19 decrease for any number of reasons including the
20 actual level of earnings and dividends, as well
21 as the impact of further impairments or common
22 equity issuances. The financial ratio metrics
23 for S&P and Moody's should also be updated and
24 considered in determining the appropriate

capitalization for Distribution.

COST RATES

Q. Please explain how the cost rates shown in Exhibit__(FP-2) were derived.

A. As illustrated in Exhibit___(FP-2), there are two separate cost rates we employed together with their respective capitalization ratios to formulate our overall rate of return recommendation. Beginning with the cost rate of the long-term debt, we reviewed the 5.64% cost rate requested by Distribution and recommend using 5.62% for the long-term debt cost rate.

Q. Why did you use 5.62%?

A. On page 2 of Company witness Smith's testimony it mentions how the fiscal year ending September 30, 2018 is being provided as a proxy for the rate year at March 31, 2018. Company witness Smith's Exhibit-(JS-2), Sheet 2, 2016, shows a long-term debt cost rate of 5.62% at September 30, 2018, not 5.64%. We reviewed the calculation of this rate and recommend using the 5.62% cost rate for long-term debt.

Q. What is the second cost rate you recommend?

A. The second rate is the cost of common equity.

Q. The second cost rate is the cost of common equity. As we will demonstrate, Distribution's 10.2% ROE request is unreasonable and should be rejected. We have developed a recommended 8.6% ROE for the rate year ending March 31, 2018.

SUMMARY OF ROE RECOMMENDATION

Q. What methodology did you use to determine the recommended ROE?

A. We estimated the cost of equity for a proxy group consisting of 26 electric utility holding companies and four gas utility holding companies. We used a DCF analysis, weighted two-thirds, and the average of two CAPM analyses, weighted one-third. The result was 8.4%. We then added twenty basis points to this result, primarily for the difference in financial risk presented by using a 42.3% common equity ratio for Distribution as opposed to the average common equity ratio of our proxy group, which is approximately 48.0%, which is discussed in more detail later in our testimony. Consequently, we recommend an ROE of 8.6%.

Q. In relation to the revenue requirement, how much is a ten basis point change in ROE and a

1 percentage change in the equity ratio worth?
2 A. Using the Company's proposed capitalization for
3 the rate year ending March 31, 2018, a ten basis
4 point change in ROE is worth approximately
5 $510,000 and a one percentage change in the
6 equity ratio is worth approximately $360,000.
7 **USE OF PROXY GROUP**
8 Q. Why do you use a proxy group in your analyses to
9 estimate Distribution's cost of equity?
10 A. The use of a proxy group to determine the cost
11 of equity is necessary because Distribution's
12 common stock is not publicly traded, and, thus a
13 direct DCF analysis of Distribution is not
14 possible. Equally important is that DCF and
15 CAPM analyses for an individual company rely on
16 equity analysts' estimates of growth and beta,
17 and those estimates could be biased or
18 inaccurate at times. By employing a
19 sufficiently large proxy group of similarly
20 situated companies in our analyses, we can
21 largely minimize the undesirable effects of
22 bias, both upward and downward, or inaccurate
23 estimates for any one company.
24 Q. Please describe how you selected your proxy

1 group?
2 A. The starting point for establishing the proxy
3 group is confirming that all of the companies in
4 the group are in the same specific industry
5 classification as the target company. This is
6 done in order to identify each company as a true
7 peer within that proxy group. Once the
8 appropriate group of peer companies is
9 established, careful consideration must be given
10 to determine the appropriate screening criteria
11 in order to obtain a group of companies that is
12 large enough without becoming unwieldy. Our
13 objective is to select a representative group of
14 companies whose risks closely match those of
15 Distribution. A careful balance must be struck
16 between these two potentially conflicting goals.
17 While the objective is to select a group of
18 companies whose risks closely match those of the
19 company being examined, it is also large enough
20 in order that we may have sufficient confidence
21 in its results.
22 Q. Please describe how you selected your proxy
23 group.
24 A. Ideally, we would have selected a proxy group

comprised entirely of regulated gas utilities whose risk profile represents, as closely as possible, the risk characteristics of the individual company being examined. However, given that the entire Value Line Investment Survey (Value Line) universe of gas utility companies consists of an insufficient number of publicly traded natural gas companies upon which to base our proxy group to produce a reasonable result, we expanded our proxy group to include electric utilities within the Value Line universe that face similar risks and of which investors have similar expectations. Accordingly, we began with a total of 11 natural gas companies. One company, Piedmont Natural Gas Inc., was eliminated from our proxy group due to its pending merger and acquisition activity, three additional companies were eliminated due to non-investment grade credit ratings and the remaining companies were not considered due to their insufficient percentage of regulated revenue. Our universe of gas utilities, Exhibit__(FP-12), illustrates our analysis of the natural gas utility proxy group,

which resulted in only four comparable natural gas utility companies.

Q. Please explain how you augmented your group with electric utilities.

A. As we already explained, due to the insufficient size of a four-company natural gas utility proxy group, we also selected a group of 26 companies from a "universe" of 41 companies whose common stock is publicly-traded and deemed to be "electric utilities" by Value Line. We then applied the following five selection criteria to the companies in the universe: (1) currently have an investment grade credit rating from Moody's and S&P; (2) have regulated utility revenue that is 70% or greater of its total revenues, as determined by each company's 2015 10-K filed with the SEC; (3) currently pay dividends; (4) have not been involved in a recent major acquisition or merger; and (5) is currently regulated by a public utility commission.

Q. Please elaborate on how you selected the 26 electric companies in your proxy group.

A. We eliminated the following eight companies from

the electric utilities universe because they do not derive at least 70% of their total revenues from regulated operations: Allete, Inc., Dominion Resources, Inc., DTE Energy Co, Exelon Corporation, NextEra Energy, Inc., Otter Tail Corporation, Public Service Enterprise Group and Vectren Corporation. We eliminated the following six companies due to recent acquisitions and mergers: Duke Energy Corporation, Empire District Electric Company, Great Plains Energy Incorporated, Hawaiian Electric Industry Incorporated, Southern Company, and Westar Energy Incorporation. Finally, we removed ITC Holdings Corp because it is not a retail distributor of electricity or natural gas, but is instead a wholesale electric transmission holding company regulated by the FERC. In total, 15 of the 41 companies covered by Value Line were eliminated due to our screening criteria. The remaining 26 utilities that meet the proxy group screening requirements are presented in Exhibit__(FP-13).

Q. Why have you limited your proxy group to electric holding companies that derive at least

1 70% of its total revenue from regulated
2 operations?
3 A. Companies that derive less than 70% of revenue
4 from state rate-regulated sources have
5 materially higher business risk than a pure
6 utility operating company. Thus, it is
7 reasonable to use a threshold requiring 70% or
8 greater regulated revenues for inclusion in the
9 proxy group.
10 Q. Why are recent major acquisitions or mergers a
11 factor in determining the proxy group?
12 A. Historically, companies that are involved in a
13 recent major acquisition or merger have the
14 potential for distorted stock prices and hence
15 their individual cost of equity estimates.
16 Q. Please explain the other factors in the
17 selection of the gas utilities for your proxy
18 group?
19 A. The majority of the gas utility companies were
20 eliminated due to below (non-investment)
21 investment grade credit ratings by Moody's and
22 or S&P. Although NiSource Incorporated's had a
23 non-investment grade rating of "Ba1" we decided
24 to include the company in our proxy group

because its principal operating subsidiary, Northern Indiana Public Service Company, accounts for over 99% of its operating revenue

Q. What is the total number of utilities in your proxy group?

A. We recommend using a proxy group totaling 30 companies, including 26 electric combination utility companies and 4 natural gas utilities as shown in Exhibit__(FP-14, Page 1). It should be noted that the majority of Value Line's universe of 41 electric combination utility companies have both electric and gas utility operations. Furthermore, our proxy only incorporated nine companies out of the 26 electric combination company that are strictly classified as electric only utilities. In the end, our goal is to establish a proxy group of utilities that is sufficient in size and have comparable risk to Distribution.

DCF METHODOLOGY

Q. Please describe your DCF methodology and its results.

A. Staff’s DCF model is a two-stage model, which explicitly recognizes that a company’s short-

term growth expectations do not necessarily equal long-term expectations. The first stage uses analysts' near-term estimates to derive the short-term growth rate, while the second stage is based on a calculation of a sustainable growth rate. The calculation of the DCF for the proxy group is shown on pages 1-2 of Exhibit___(FP-15). It is important to note that, while earnings drive companies' dividend payout policies, the value of the companies' common stock is equal to the present value of all future dividends. This is because the earnings that are retained will only have value to the stockholder when they are paid as dividends in the future. Underlying this principle is the strong assumption in the capital market theory that companies earn the same return on retained earnings as the market demands on their common stock. Also, fundamental to the DCF methodology is the sentiment that cash and or earnings held in the future do not hold the same worth as cash or earnings in present time. Due to the time preference of customers to spend their cash

today rather than waiting and the effects of inflation and productivity on upon future cash flows, the DCF discounts the future expected cash flows according to investor's return requirements. The primary reason why the DCF methodology continues to be the preferred approach for determining a company's cost of equity is that investors' immediate return requirements, as observed in current stock prices and recent dividends, are readily quantifiable.

Q. How have you estimated the companies' stock prices?

A. Each company's stock price was estimated using the three-month average of the high and low price for each month during for three-month period ending June 2016. Stock prices are shown on Exhibit__(FP-17).

Q. What are the results of your proxy group's cost of equity using the DCF methodology?

A. The DCF mean ROE for the proxy group is 8.29% and the median is 7.87%, as shown on Exhibit__(FP-15, Page 2).

Q. Do the individual company results within the

proxy group appear reasonable?

A. Yes. The lowest ROE is 6.32% and the highest ROE is 11.25% with 29 of the 30 (96.7%) values within two standard deviations of the mean. While most of the individual company results appear reasonable, we do not recommend a cost of equity based on any of the individual results due to the potential for biased or inaccurate estimates influencing the results.

Q. Do you have any concerns with external factors that might be impacting the financial markets and the DCF results?

A. Yes. There have been several significant disruptions in the market recently that we believe have affected Staff's ROE model results. Specifically, Britain's decision to withdraw from the European Union, the Federal Reserve's "go slow" approach on raising interest rates in recognition of the economy's continued slow growth and the volatility in oil prices. Investors have fled to less risky investments including utility stocks, which pushed the S&P 500 Utilities Index to a record high of 258.15 in the month of June as reported in the

following article, U.S. Utility Index Hits Record In Flight to Safety After Brexit, Exhibit __(FP-16). The increased demand for utility shares has increased the market-to-book ratio (MBR) of Staff's proxy group. At September 2011, the MBR for Staff's proxy group was 1.3x compared to Staff's current proxy group MBR of 1.9x.

Q. Did you find it appropriate to adjust Staff's methodology in light of these externalities?

A. We considered a number of alternatives, and we did identify the need to alter our methodology in one particular aspect. Staff has consistently advocated using the median DCF value as it mitigates the undue influence of potential outliers (very low and/or very high results) skewing the recommendation. However, very recently it appears to us that using the median is suppressing the ROE below what the "average" or "typical" investor in the proxy group would require at this time. Also, as 29 of the 30 ROE results fall with two standard deviations of the mean, these results are a good distribution. In consideration of these

1 factors, we recommend using the mean DCF result
2 of 8.29% in the overall ROE calculation instead
3 of the median value of 7.87%.
4 Q. How are short-term and long-term dividends
5 projected to change over time?
6 A. Our analysis maintains the same approach the
7 Commission has employed for many years. The
8 calculation of the proxy group's dividend growth
9 as measured by the DCF methodology is displayed
10 in Exhibit__(FP-15, Page 2). In the first stage
11 of our DCF model, for the years 2016 through
12 2020, we rely on Value Line analysts' estimate
13 of the dividend growth rate for each company in
14 the proxy group. In the second stage, for the
15 year 2021 and beyond, a sustainable growth rate
16 is calculated for each company within the proxy
17 group based on its projected retention of
18 earnings and growth of its common stock. We
19 also include the expected growth from issuing
20 common equity above/below book value. The cost
21 of equity is then calculated by solving for the
22 discount rate necessary to set the net present
23 value (NPV) of the 200-year dividend stream for
24 each company equal to its current stock price.

As illustrated on page 2 of Exhibit__(FP-15),the proxy group's average short-term growth rate is 5.32% and its average sustainable growth rate is 4.92%.

Q. How did you check the reasonableness of your long-run sustainable growth rate?

A. We compared the sustainable growth rate result for the DCF of our proxy group to the most recent long-range consensus growth rate estimate of the nominal Gross Domestic Product (GDP). We find it reasonable to expect a correlation between the future dividend growth rate and the overall economic growth rate in the economy as measured by the growth rate in GDP. We do not advocate a comparison with historical growth rates, since historical periods are likely not representative of the future.

Q. How does your estimated sustainable dividend growth rate of in the DCF model compare with the macroeconomic indicators of the overall economy?

A. Although, our proxy group's median sustainable growth rate exceeds the most recent consensus long-range growth estimate of nominal GDP, our long-term growth rate is a considerably closer

match to the nominal GDP relative to Company witness Bulkley's growth rate estimate. Using the March 10, 2016, edition of Blue Chip Economic Indicators, as illustrated in Exhibit__(FP-18), the consensus long-range estimates for Nominal GDP growth is 4.20% for the 2018-2022 time period as well as 4.20% for the more distant 2023-2027 time period. The 4.92% average sustainable growth rate of our proxy group appears reasonable in comparison to Company witness Bulkley's sustainable growth rate of 5.36%. Staff's 4.31% median sustainable growth rate is close to the current consensus growth rate in as measured by the nominal GDP.

Q. Why is the nominal GDP growth rate an appropriate proxy for Staff's sustainable growth rate?

A. Because it is reasonable for investors to expect their future dividends to generally keep pace with productivity gains and the changes to inflation as measured by the economy as a whole.

CAPITAL ASSET PRICING MODEL

Q. Please briefly explain the CAPM theory.

A. The principle behind the CAPM theory is that

there is no premium, in terms of expected return, for bearing risks that can be eliminated through diversification. The CAPM model says the expected return of security or a portfolio is equal to the rate on a risk-free security plus a risk premium multiplied by the asset's systematic risk. Systematic risk is a risk that is common to all equity securities and cannot be eliminated through diversification and is measured by beta. Changes in interest rates, recessions and wars are examples of systematic risks.

Q. What assumptions is the CAPM based on?

A. The model is based on the assumptions that: (1) the capital market is competitive and efficient; (2) investors are risk-averse and demand higher returns for higher risk; (3) market participants can lend and borrow unlimited amounts under the risk free rate of interest; and (4) investors hold diversified portfolios and operate in capital markets with no transaction costs, taxes, or restrictions on financial transactions.

Q. Please describe the calculation used in the

traditional CAPM.

A. The traditional CAPM formula is:

$K = R_f + \beta*(R_m - R_f)$ where:

K = investor's required return or equity cost of capital;

R_f = risk-free rate;

β = beta;

R_m = market rate of return; and

$R_m - R_f$ = market risk premium.

Q. How does a firm's beta measure risk?

A. Beta is a measure of how closely correlated the return for a particular stock is to the return on the market as a whole. A beta of 1.0 indicates that the stock's return mirrors the return of the market as a whole. Betas of less than 1.0, which are typical for utility stocks, indicate that the stocks are less volatile than the market as a whole. Accordingly, the CAPM informs investors they will only be compensated for actual risk, as measured by beta. Thus, in terms of estimating the return requirements of utility investors, the CAPM results will express the degree to which utility stocks are less volatile relative to the general market.

1 Q. Please describe the methodology you used to
2 determine your CAPM results.
3 A. Consistent with the approach Staff has employed
4 and the Commission has adopted for many years,
5 we averaged the results of two forms of the CAPM
6 the traditional CAPM and the zero-beta CAPM.
7 Q. Why did you use two forms of the CAPM?
8 A. Prior research has revealed that the traditional
9 CAPM model can possibly underestimate the
10 required return when betas are below 1.0. The
11 zero-beta CAPM determines the cost of equity for
12 the proxy group by multiplying .75 times beta
13 times the risk premium and adding .25 times the
14 risk premium.
15 Q. How did you estimate the risk-free rate?
16 A. The risk-free rate was estimated by averaging
17 the ten-year and 30-year Treasury bond yields
18 for the recent three-month period, April 2016
19 through June 2016. The average for the three-
20 month period ending June 2016 was 2.16%.
21 Q. Why did you use a three-month average for the
22 risk-free rate calculation?
23 A. The Commission began employing three-month
24 average yields in 2009 Consolidated Edison

1 Company of New York Inc., Case 09-E-0428, so
2 that the three-month timeframe used in its CAPM
3 calculation would be consistent with the three-
4 month timeframe employed in its DCF analysis.
5 Q. Is the use of a three-month average appropriate?
6 A. Yes, we consider that the use of a three-month
7 average to be appropriate because it smooth's
8 out any potential short-term volatility, while
9 at the same time maintaining a realistic
10 representation of investor's current
11 expectations.
12 Q. Why did you employ ten-year and 30-year Treasury
13 bond yields as the risk-free rate in your
14 calculation?
15 A. The blending of the yields on Treasury
16 securities with ten-year and 30-year maturities
17 is reasonable because it approximates the time
18 horizon of most investors. Utility investors
19 generally have both intermediate and long-term
20 investment horizons, so the use of both the ten-
21 year and 30-year Treasury securities is
22 appropriate. In the Order Establishing Rates
23 for Electric Service, Case 10-E-0362, the
24 Commission indicated its preference for

1 averaging the two Treasury yields. On page 75
2 of that Order, the Commission noted, "…using a
3 combination of treasury yields is consistent
4 with our practice and supported by the varying
5 nature of investor holding periods."
6 Q. How did you determine the beta for the CAPM?
7 A. We used the beta for each of the 30 companies in
8 our proxy as reported by Value Line and
9 calculated the median result of .70.
10 Q. How does Value Line calculate beta?
11 A. Beta is derived from a regression analysis of
12 the relationship between weekly percentage
13 changes in the price of a stock and weekly
14 percentage changes in the NYSE Index over a
15 period of five years. With shorter price
16 histories, a shorter time period is used, but
17 two years is the minimum. The five-year time
18 period used by Value Line is a sufficient time
19 frame to produce reliable estimates of stock
20 prices. Value Line also "smoothes" the "coarse
21 betas" to reflect the theory that betas have a
22 natural tendency to converge to 1.0.
23 Q. What are the disadvantages of using beta in the
24 CAPM methodology?

A. Although beta is useful in calculating stock price variability and its relative risk to the stock market's volatility, beta does necessarily readily incorporate new information. In a mature industry, like utility stocks, beta measures stock price changes based on its historical record. If a company's capital structure weakens and or its management take on substantial business risk, those new factors are not measured by its prior beta calculations and do not reflect its current or future risk as measured by beta. Thus, its measurement of past stock price movements are poor predictors of future stock price changes. Another shortcoming of beta is that sometimes there is a wide disparity in its measurement by the various firms who calculate it. The Commission has relied upon Value Line's reported betas for more than 20 years. Other firms, like Bloomberg, apply shorter time periods, which can produce notable variances in the beta results.

Q. Why did you use Merrill Lynch data for calculating market risk premiums?

A. Our market risk premium (MRP) is derived from

1 Merrill Lynch's two forward-looking returns on
2 the market, a required return and an implied
3 return. The Commission has consistently applied
4 and implemented this market risk premium
5 methodology since 1996, in Case 95-G-1034. In
6 the Central Hudson Gas & Electric Corporation
7 Order and Opinion No. 96-28, on page 14 the
8 Commission approved the use of the Merrill Lynch
9 estimate. In its Opinion, the Commission
10 stated, "…the Judge's market return calculation
11 based on Merrill Lynch data is a reasonable
12 method of deriving a risk premium."
13 Q. Why are you using an average of the most recent
14 three months of Merrill Lynch's expected market
15 returns in your calculation?
16 A. We used expected market return estimates from
17 the most recent three months in order to be
18 consistent with the timeframes of the other data
19 as employed in our CAPM and DCF calculations.
20 By matching the timeframe upon which our risk-
21 free rate is calculated, we can achieve a more
22 representative estimate of the required MRP.
23 Q. Why didn't you rely on an ex-post (historical)
24 method to derive the appropriate MRP?

A. The application of the historical market risk premium method is problematic because *ex-post* MRP's are based on the faulty premise that past performance is a valid proxy for expectations regarding future results. In addition, the historical approach is highly sensitive to the actual time period selected to calculate the premium.

Q. Has the Commission ever stated its preference for relying on forward-looking MRP analyses as opposed to ex-post analyses?

A. Yes. In Case 95-G-1034, on page 14, the Commission stated that, "…the Judge's market return calculation based on Merrill Lynch data is a reasonable method of deriving a risk premium; and it avoids the problem of stale data in the Ibbotson estimate."

Q. How did you determine what MRP to use and what was your result?

A. The MRP is the difference between the expected market return and the rate on a risk-free investment. In order to determine the expected market return, we utilized the April, May and June 2016 editions of Merrill Lynch's

1 Quantitative Profiles. As illustrated in
2 Exhibit___(FP-19), the average of Merrill
3 Lynch's "Implied Return" and "Required Return"
4 methods is 10.95%. Given the risk-free rate of
5 2.16%, the MRP is 8.79%.
6 Q. What are the traditional CAPM results using your
7 stated inputs?
8 A. We determined the traditional CAPM result to be
9 8.31%, calculated as follows:
10 2.16% + [0.70 * (10.95% - 2.16%)] = 8.31%.
11 Q. What are the zero-beta CAPM results using your
12 stated inputs?
13 A. 8.97%, calculated as follows:
14 2.16% + [.75*.70*(8.79%)] + [.25*(8.79%)].
15 Q. What is the average for the traditional and
16 zero-beta CAPM calculations?
17 A. 8.64%, as illustrated in Exhibit__(FP-19).
18 Q. What is the ROE result using a 2/3 DCF and a 1/3
19 CAPM weightings.
20 A. The resulting ROE is 8.40%.
21 Q. Has the Commission commented on this methodology
22 recently?
23 A. Yes. This methodology was recently reaffirmed
24 in the Commission’s rate order in Case 10-E-

1 0362, Orange and Rockland Utilities Inc. (issued
2 June 16, 2011). In that case the Commission
3 stated that: "…we have repeatedly affirmed
4 certain key elements of the methodology we use
5 in determining the appropriate cost of equity to
6 be included in rate. These include (1) the
7 application of DCF and CAPM analyses to a
8 representative proxy group of utility companies;
9 (2) utilization of a two-stage DCF computation
10 with inputs derived from Value Line; (3) basing
11 the CAPM result on an average of the outcome
12 from standard and zero-beta models with a risk-
13 free rate based on Treasury bonds, MRP provided
14 by Merrill Lynch's Quantitative Profiles, and
15 betas taken from Value Line; and (4) a 2/3 - 1/3
16 weighting of the DCF and CAPM results,
17 respectively."
18 Q. Why is it reasonable to weight the DCF greater
19 than the CAPM in estimating the ROE?
20 A. The CAPM should be given less preference
21 relative to the DCF because the CAPM components
22 are less observable and are more dependent on
23 estimations. The inputs in the DCF model are
24 readily observable outside of the dividend

growth rates. The DCF application of fewer subjective inputs relative to the CAPM provides a more stable foundation, thus a lesser chance of error in a ROE calculation. The strength of the DCF model has been recognized by the Commission by its 2/3 weighting in continuous rate proceedings. While the CAPM presents a conceptual framework that provides a reasonable estimate of a firm's cost of equity, the CAPM weakness provide a less stable foundation in the calculation of the return of equity. Given some of the weaknesses of the CAPM discussed previously in our testimony, the Commission should continue to accord the CAPM methodology a 1/3 weighting.

Q. Why do you recommend the lesser (1/3) weighting for the CAPM?

A. Over the past 20 years, Staff has advocated giving the CAPM less weight in the overall ROE calculation than the DCF. This has primarily been due to the subjectivity of the MRP and fluctuations in beta. In addition, there are wide ranging inputs (growth rates, DCF inputs, historical versus future estimates for market

returns, time periods for market returns, source for market returns) used in estimating the MRP, which result in large differences.

UNADJUSTED RETURN ON EQUITY CONCLUSION

Q. Please explain how you determined your overall cost of equity for the proxy group.

A. We weighted the DCF result (8.29%) as two-thirds of the total and the CAPM average (8.64%) as one-third of the total, which resulted in an 8.40% cost of equity. These calculations can be seen on Exhibit__(FP-19).

ADJUSTMENTS TO THE ROE METHODOLOGY RESULT

Q. You mentioned earlier in your testimony that you added twenty basis points to the ROE result of 8.4%, for a recommended ROE of 8.6%? What is your reasoning for this?

A. Staff's proxy group of electric and gas utilities has an approximate common equity ratio of 48.0%. We are recommending the use of National Fuel Gas Company's common equity ratio of 42.3% for use in the capitalization for Distribution. As Staff's proxy group has an average equity ratio that is significantly higher than National Fuel Gas Company's equity

ratio, there is additional financial risk attributed to Distribution by recommending to use a 42.3% equity ratio. In addition, many of the electric companies in Staff's proxy group have exposure to generation risk and while you would expect the companies to have a thicker equity cushion for this risk, we realize that it may be a few percent. In consideration of these differences, we find that an additional 20 basis points is a reasonable amount to capture this added financial risk and recommended an ROE of 8.6%.

DISCUSSION OF ANN BULKLEY'S ROE APPROACH

Q. Please summarize the approach followed by the Company's ROE witness, Ann Bulkley.

A. Company Witness Bulkley implemented the DCF model and the CAPM methodology in establishing her recommended ROE range of 9.65% to 10.20%. She also used two separate proxy groups, one comprised of both electric utility holding companies and natural gas distribution holding companies, which she identified as her "Combined Utility Proxy Group". Her second group used only natural gas distribution holding companies

1 and is identified as the "Natural Gas Proxy
2 Group". She used earnings growth rates from
3 Zack's, Yahoo Finance and Value Line. She
4 developed three multi-stage DCF models utilizing
5 the high, mean and low growth rates of Zack's,
6 Yahoo Finance (First Call provides the financial
7 data) and Value Line growth estimates. She ends
8 up with three DCF results for each proxy group,
9 for a total of six DCF ROE results. For her
10 CAPM, she used a market return of 13.38% with
11 three different risk-rates and utilized the
12 traditional CAPM and the zero-beta CAPM for both
13 of her proxy groups. She then combined the DCF
14 and CAPM results for each proxy group and
15 recommended a range of ROE values of 9.65% to
16 10.2%. Although, Company witness Bulkley's mean
17 ROE calculation is 9.93% and her median ROE
18 calculation is a 9.91% ROE, in this proceeding
19 Distribution is requesting the high end of
20 Company witness Bulkley's ROE range for a one-
21 year rate plan.
22 Q. What are your principal points of contention
23 with Company witness Bulkley's analyses?
24 A. For her DCF methodology, our primary concerns

regard the composition of her proxy groups and her use of excessively high short term (1st stage), intermediate growth rates (2nd stage) and terminal growth rates. With respect to her CAPM methodology, we are primarily concerned with her flawed approach to derive a 13.38% market return that she employs in both her traditional and zero-beta CAPM calculations. Finally, we strongly disagree with her recommendation that the DCF and CAPM be accorded equal weighting.

Q. Please explain the concerns you have regarding the composition of Company witness Bulkley's Combined Utility proxy group.

A. We find the proxy group selection criteria of requiring 70% of total operating income requirement from 'regulated utility' operations and eliminating utilities that derive less than 50% of operating income from regulated natural gas distribution operations to be too restrictive. Her methodology resulted in the elimination of multiple companies whose risk characteristics are closely comparable to the others in the proxy group. In our Exhibit__(FP-20), we illustrated some of the primary

differences between Staff's proxy group and Company witness Bulkley's proxy groups. The companies that were eliminated from her proxy group, but meeting Staff's criteria include: American Electric Power Co. Inc.; Black Hills Corp.; Edison International; El Paso Electric Co.; Entergy Corp; Eversource Energy; First Energy Corp.; IDACORP Inc.; MGE Energy Inc.; OGE Energy Corp.; PG&E Corp.; Pinnacle West Capital Corp.; PNM Resources Inc.; Portland General Electric Co.; PPL Corp.; and WEC Energy Group. In addition, her application of operating income (earnings) instead of regulated revenue for establishing the proxy group may allow companies into the group that contain substantially greater risk than a typical regulated utility. Regulated revenues more accurately reflect a company's exposure to riskier competitive operations, because it is not uncommon for competitive business ventures to be periodically unprofitable. Using 70% of operating income criteria could introduce companies into the proxy group that have a higher inherent risk profile than is proper for a regulated utility

1 proxy group.
2 Q. Are there any other differences between your
3 proxy group and either of Company witness
4 Bulkley's proxy groups?
5 A. Yes. There is a large difference in the revenue
6 for non-regulated operations between Staff's and
7 Company witness Bulkley's proxy groups. For the
8 year ending 2015, the utility holding companies
9 that comprised our proxy group received, on
10 average, 8.71% of their revenue from non-utility
11 activities. Company witness Bulkley's Combined
12 Utility proxy group had 21.1% of sales from non-
13 utility business, as shown in Exhibit___(FP-20).
14 While at the same time, Company witness
15 Bulkley's Natural Gas (only) proxy group
16 averaged 34.1% of non-regulated utility revenue
17 for 2015.
18 Q. What does the larger presence of riskier non-
19 utility operations imply with respect to
20 investor return requirements?
21 A. The inclusion of holding companies whose
22 operations are exposed to higher levels of
23 competitive market forces means that both of
24 Company witness Bulkley's proxy groups have

1 significantly higher business risk profiles than
2 those of Staff's proxy group. With all else
3 being equal, these higher business risk would
4 incline a reasonable investor to naturally
5 require a higher rate of return on their equity
6 investment to compensate for the perception of
7 increased risk.
8 Q. Provide an example of how a company with a
9 higher risk profile could enter into a proxy
10 group with Company witness Bulkley's selection
11 criterion.
12 A. Operating income is the amount of revenue left
13 over after accounting for all the expenses
14 necessary to keep the business running. If a
15 company has nearly equal revenue from two or
16 more of its business segments but one of those
17 segments has drastic increases or decreases in
18 its cost of goods, that business segment will
19 typically face higher business risk relative to
20 its other business segments that don't face such
21 drastic changes in its underlying expenses. A
22 holding company that receives 30% of its
23 revenues from utility sources and 70% from
24 risker non-regulated sources could be included

in Company witness's proxy group if the non-regulated sources had little or no operating income and a normally performing regulated utility subsidiary. In that situation the high percentage of operating income from the utility would allow it admittance into the group, but, because of its level of exposure to higher risk non-regulated operations, its risk profile would be well above that of a typical utility by any reasonable standard. For this reason, we find that regulated revenue is a better selection criterion to use in selecting a proxy group.

Q. Do you see any justification why the Company witness Bulkley applied an equal weighing of the DCF and CAPM results?

A. No. Since 1994 the Commission has consistently preferred cost of equity determinations with 2/3 DCF and 1/3 CAPM weightings. For example, in the 2014 Consolidated Edison Company of New York, Inc. Rate Order in Case 13-E-0030, et al., the Commission authorized a ROE based upon a weighting of the two methodologies: a two-third weighting for the DCF and a one-third weighting for the CAPM. Again, in Case 06-E-1433, Orange

1 & Rockland – Electric Rates (issued October 18,
2 2007) the Commission authorized ROE was based on
3 a two-thirds DCF, one-third CAPM methodology.
4 Furthermore, in Case 95-G-1034, Central Hudson
5 Electric and Gas Corporation - Gas Rates (issued
6 October 3, 1996), the Commission authorized ROE
7 was based on a two-thirds DCF, one-third CAPM
8 methodology.
9 Q. Please elaborate how Company Witness Bulkley's
10 use of short-term and long-term (terminal)
11 growth rates affect her DCF model?
12 A. As we discussed earlier, Company witness
13 Bulkley's model is undermined by its short-term,
14 intermediate and long-term growth rate
15 assumptions. Specifically, her model uses
16 earnings growth rates to determine short-term
17 dividend growth rates, ignoring available
18 dividend growth rates or forecasts. This is
19 direct contrast to the basic premise of the DCF
20 which measures the present value of future
21 dividends. The application of Company witness
22 Bulkley's earnings growth simply assumes that
23 dividend growth will match earnings growth,
24 although her testimony failed to present

evidence to support such an expectation. However, a larger concern, is her application of a historically derived real GDP rate, in conjunction with a forecasted inflation rate as the long-term growth rate of her proxy groups. In addition, Company witness Bulkley's application of the real GDP, together with a forecasted inflation rate as her long-term growth rate, is a poor proxy for the long-term growth rate of the companies in the proxy group. While long-term GDP growth is useful as a reasonableness check on one's analysis, it should not be substituted to estimate future expected dividends of individual companies or market sectors. The use of expected GDP growth also ignores the implication of accretion or dilution on a company when it issues new shares of stock.

Q. Please explain your concerns with Company witness Bulkley's application of three different growth rates within her DCF Model.

A. She utilizes three separate growth rates within her multi-stage DCF model. She has not provided any explanation or research demonstrating that

the three-stage dividend growth model more accurately reflects investors' pricing decisions than the Commission's long-preferred two stage growth analysis.

Q. Do you have any concerns with Company witness Bulkley using three different earnings growth sources?

A. Yes, her use of three different sources is also problematic because it does not provide a direct comparison, in that Yahoo Finance (First Call) and Zack's do not explain on the impact of earnings growth forecasts on the respective dividend payout policies of the companies within her proxy groups. Her short-term dividend projections are a direct result of the average earnings growth estimates of three different sources, without any consideration to the effect of future dividend payouts. It is important to note, Company witness Bulkley's short-term (1st stage) growth rates average 5.97% and her intermediate (2nd stage) growth rates average 5.66%, both of which exceeded Staff's average short-term growth rates of 5.32%, as well as, the Blue Chip Economic Indicators 4.20% estimate

1 for Nominal GDP.
2 Q. Please discuss how Company witness Bulkley
3 developed her short-term dividend growth rate of
4 her proxy groups.
5 A. In the first stage of Company witness Bulkley's
6 DCF model, the current annualized dividend for
7 each company within her proxy group is
8 accelerated to a five year period based on the
9 average of the three to five year earnings
10 growth estimates as reported by Yahoo Finance
11 (First Call), Zack's, and Value Line.
12 Q. What are your concerns with this dividend
13 application by Company witness Bulkley?
14 A. It is highly unlikely that investors would rely
15 exclusively on the earnings per share growth
16 rate forecasts of Wall Street analysts in
17 determining short-term dividend projections.
18 The (Dr. Robert) Harris study from 1992 noted on
19 page 51 and 52 of Company witness Bulkley's pre-
20 filed testimony asserts that, "…a growing body
21 of knowledge shows that analyst's earnings
22 forecasts are indeed reflected in stock prices.
23 Such studies typically employ a consensus
24 measure of FAF (financial analyst earnings

1 forecasts) calculated as a simple average of
2 forecasts by individual analyst." Although, we
3 agree that all relevant information is
4 incorporated into a company's stock price, the
5 direct relationship of earnings to dividend
6 growth that Company witness Bulkley assumes is
7 remote. Dividend payout ratios will change due
8 to many factors including individual company
9 cash flow requirements, current economic
10 conditions, and future market conditions in
11 addition to other factors. Rational investors
12 will not just look at expected earnings but will
13 also factor in all relevant information when
14 estimating growth rates.
15 Q. Why do you find that Value Line short-term
16 dividend projections are better to use than
17 those in Company witness Bulkley's model?
18 A. On page 53 of her testimony, she claims that
19 Value Line projections of short-term dividend
20 growth do not explicitly include growth in
21 retained earnings and their use is not
22 appropriate for the DCF calculation. What she
23 has failed to recognize is that, while the long-
24 term dividend growth is constrained by the

combination of retention growth and issuing stock above and or below book value, in the short-term, dividend policy can drastically change and result in dividends to grow above or below retention growth. Consequently, her short-term dividend projections are a direct result of the average earnings growth estimates of three different publications, without any consideration upon the growth rates effect on future dividend pay outs. Our use of Value Line dividend growth projections recognizes the impact of changes in payout policy while her sole use of short-term earnings forecasts does not.

Q. Does Company witness Bulkley have other criticisms of Staff's application of Value Line's dividend growth rates?

A. Yes. Company witness Bulkley indicated that Value Line's dividend growth projections are a reflection of expectations of a "single analyst" and thus, attempts to discredit Staff's utilization of those estimates by Value Line by claiming the publication lacks expectations of "multiple analysts" viewpoints. Although Value

Line assigns a lead analyst in both its electric utility and gas utility industries, each report goes through a continual evaluation and quality control process where multiple analysts review the reports before they are posted. A correspondence describing this process is in Exhibit___(FP-21).

Q. Is there another advantage in using Value Line projections in your analysis?

A. Yes. Staff and the Commission have reasonably relied on Value Line for many years. This methodology is generally understood by the investment community and lends a degree of predictability to the New York rate setting process. While this consistency does not help to identify the return that equity investors currently require, it is important in the sense that it provides predictability in the earnings level that investors in New York utilities can expect. This is particularly important to the major credit rating agencies, who view unpredictability as an additional risk.

Q. You have previously stated that Company Witness Bulkley's estimated long-term dividend growth is

1 based upon expected GDP growth and a projected
2 inflation rate. How did she calculate the GDP
3 growth rate and the projected inflation rate?
4 A. The company witness utilized a 3.24% historical
5 growth in real GDP that's based on the 1929 to
6 2015 period, as illustrated in Exhibit__(AEB-3).
7 Company witness Bulkley then calculated an
8 expected inflation rate of 2.05% based upon an
9 average of the compound annual Consumer Price
10 Index (CPI) growth rate forecasts for years 2022
11 to 2026, the compound annual growth rate of the
12 CPI for all urban consumers as projected by the
13 Energy Information Administration (EIA) for
14 years 2025 to 2040, and the compound annual GDP
15 Price Index for years 2025 to 2040. Although,
16 adding these two factors together would result
17 in a 5.29% growth rate, Company witness Bulkley
18 also applied a weighted formulaic calculation
19 that increased the results to a 5.36% estimated
20 terminal growth rate.
21 Q. Do you agree with her use of a historically-
22 derived average Real GDP as a surrogate for
23 investors' expectations with respect to future
24 Real GDP growth?

A. No. We do not consider her use of the historically derived real GDP as the long-term growth rate to be appropriate for reasons we previously discussed, but specifically because historical growth rates measure time periods that encompassed far different circumstances relative to our current economic conditions. In addition, her calculation does not accurately measure GDP growth, in such that her 2.05% inflation rate forecast is primarily (2/3) composed of two Consumer Price Indexes. The CPI measures changes in the price level of a basket of consumer goods and services but unlike the GDP deflator, the CPI does not measure inflation over the entire economy. Additionally, her use of the real historical GDP growth rate from 1929 to 2015 is inappropriate because while historical averages provide insight into how past factors might have influenced past changes in GDP, they are poor indicators of future economic activity. While, on the other hand, the Long-Range Consensus U.S. Economic Projections provided by Blue Chip Economic Indicators, which we previously discussed, and

1 employed in validating our recommended DCF model
2 is a good source regarding future economic
3 activity growth that builds upon historical
4 trends and takes into account current economic
5 conditions. This report also reflects the
6 forward-looking consensus of approximately 50 of
7 the financial community's prominent economists.
8 According to the Blue Chip Economic Indicators
9 March 10, 2016 publication, Exhibit___(FP-18),
10 the consensus long-run nominal GDP growth rate
11 is currently 4.2%, which includes both real GDP
12 and expected inflation components. Company
13 witness Bulkley's long-term growth rate of 5.36%
14 is approximately 27% higher than that of the
15 forecasted GDP growth rate of 4.2%.
16 Q. Do you agree with Company witness Bulkley's
17 assumption that her expected GDP growth rate, in
18 conjunction with a projected inflation rate, is
19 a reasonable proxy for the long-term dividend
20 growth rate in multi-stage DCF analysis?
21 A. No. Company witness Bulkley uses a historical
22 real GDP growth rate of 3.24% and an inflation
23 rate of 2.05%, to generate a combined long-term
24 nominal GDP growth rate of 5.36%. Her

assumption is based upon the, "…common theoretical assumption that, over the long-run, all the companies in the economy will tend to grow at the same constant rate." A reasonable investor would consider the projected decrease in sales growth for a mature industry, such as the electric and gas utility industry rather than implement the long-term real GDP growth rate as applied by Company witness Bulkley. In addition, our countries movement from a manufacturing economy to a service economy, its energy conservation measures, and the advent of distributed generation all foretell that gas usage growth will likely fail to keep pace with our national economic growth rates as a whole going forward.

Q. Are there any other sources of GDP growth that appear more reasonable relative to Company witness Bulkley's historically based GDP growth estimate?

A. Yes. The EIA' 2015 Annual Energy Outlook with Projections to 2040, Exhibit___(FP-22), states that, "…real GDP grows at an average annual rate of 2.4% from 2013 to 2040."

Q. What other concerns do you have with Company witness Bulkley's terminal DCF growth rate of 5.36%?

A. Her terminal growth rates exceeds Staff's growth rate by 105 basis points and greatly impacts her average DCF calculation of 9.19% relative to Staff's DCF calculation of 8.29%.

Q. Would you please summarize Company witness Bulkley's CAPM approaches?

A. Her analysis resulted in six ROE estimates using the traditional CAPM and six ROE estimates using the zero-beta CAPM. Her CAPM models used a Value Line beta, Bloomberg beta, with three different risk-free rates. All of the CAPM models used the same Bloomberg Professional market return estimate of 13.38%

Q. Please explain how she derived each of the three major components used in her CAPM methodologies; the risk-free rate, beta and the market risk premium.

A. Company witness Bulkley's two CAPM methodologies use three primary inputs, a risk-free rate based on the current (as of February of 2016) three-month average yield on 30-year Treasury Bonds

1 (2.82%), the projected 30-year Treasury yield
2 for first quarter of 2016 to the second quarter
3 of 2017 (3.35%), and the projected 30-year
4 Treasury yield for the period 2017-2021 (4.50%).
5 She used an estimated S&P 500 required market
6 return of 13.38% and calculated three separate
7 MRP's suing the risk-free rates mentioned above.
8 She used two separate beta calculations within
9 her two CAPM methodologies. Her two beta inputs
10 from Value Line (.747) and Bloomberg (.603)
11 averaged 0.675. The traditional CAPM results
12 ranged from a ROE of 9.19% to 11.22%, and the
13 zero-beta CAPM ranged from 10.23% to 11.76%.
14 Q. Company witness Bulkley argues that the
15 Commission's preferred approach is flawed
16 because it does not address a companies'
17 expected economic (asset) life, the equity
18 duration of the utility industry, or what
19 Morningstar suggests is, "…the time horizon of
20 the chosen Treasury security is that it should
21 match the time horizon of whatever is being
22 valued," on page 64 of Company witness Bulkley
23 pre filed testimony. Do you agree with her
24 arguments?

A. No. While she is correct that utility plant assets have very long lives, and we would agree that sound financing practices generally dictate these long-lived assets be financed with similarly long-lived securities, her conclusion that all utility equity investors have an investment horizon of 30 years is unsubstantiated. Utility companies commonly fund their long-term obligations with a variety of time horizons.

Q. Are Company witness Bulkley's expectations of increased interest rates reasonable?

A. She mentions that Goldman Sachs suggested the Federal Reserve will need to increase rates at its originally projected four times in 2016, due to an increase in core inflation. The Federal Reserve has not yet raised rates in 2016. Additionally, ten-year risk-free rates have fallen from 2.09% in January 2016 to 1.64% in June 2016, which is a significant drop.

Q. Is Company witness Bulkley's application of treasury projections appropriate for the CAPM methodology?

A. No. The Commission and staff have maintained

for many years, and as mentioned earlier, current rates are the best indicator of future rates as they are based on the latest available information to investors.

Q. Please explain your concerns regarding the source and application of Company witness Bulkley's beta estimates.

A. The Commission has consistently utilized Value Line betas, and one of the principal reasons for doing so is because Value Line calculates its betas over a five year period, thereby mitigating the inherent volatility of using beta estimates calculated over shorter time periods. Bloomberg's beta determinations are only calculated over a two year period, and thereby introduces an unwarranted degree of volatility into her beta determinations, and by extension, to the CAPM estimates themselves.

Q. Please explain your concerns with Company witness Bulkley's market return of 13.38%.

A. The market return of 13.38% exceeds Staff's market return of 10.95% by 243 basis points, and exceeds the average return for the S&P of 9.0% for the period 2006-2015, by over four percent.

1 Her approach relies entirely upon a constant
2 growth DCF analysis of the S&P 500. Company
3 witness Bulkley assumes that the five year
4 earnings growth rate estimates from Bloomberg
5 Professional will last into perpetuity, which we
6 find unreasonable.
7 **ROE METHODOLOGY WEIGHTING**
8 Q. Would you please elaborate on the
9 appropriateness of your proposed weightings;
10 specifically your recommendation a 2/3 DCF and
11 1/3 CAPM?
12 A. The DCF methodology has long been the favored
13 approach to calculating the cost of equity at
14 commissions throughout the country, including
15 New York. In the Commission's Order Setting
16 Electric Rates, Case 08-E-0539 issued April 24,
17 2009, the Commission stated that, among the
18 reasons it accords a two-thirds weighting to the
19 DCF methodology, is that, "…the DCF relies on
20 readily available data to make objective
21 estimates of investors' return requirements.
22 While the DCF has one input of primary
23 controversy (growth), two CAPM inputs (beta and
24 the market risk premium) are dependent on

1 estimates which are contested and volatile."
2 Q. Given the Commission's approved ROEs in recent
3 rate proceedings do you believe that a rational
4 investor would expect the Commission to
5 authorize the 10.2% ROE requested by the
6 Companies in this proceeding?
7 A. No. Rational investors are well aware of the
8 Commission's time tested formulaic approach to
9 the cost of common equity, as presented in our
10 analysis. Plus, as we discussed earlier,
11 approximately 73% of the revenues for
12 Distribution are subject to either deferrals or
13 true-ups that include gas adjustment costs,
14 purchased gas costs, a RDM and pension and
15 OPEBs. With only 27% of Distribution's revenues
16 subject to uncertainty, such a high ROE is
17 excessive.
18 Q. Earlier you stated that you have considered
19 alternatives or variations to Staff's
20 methodology in light of a number of external
21 factors that appear to be impacting the
22 financial markets and, by extension your ROE
23 methodology. Please explain the variations to
24 Staff's ROE methodology that you find the

1 Commission could consider?
2 A. The first option is to not update the ROE model
3 from March 2016 due to current market
4 distortions, which produce equity interest rate
5 yield information that may not be representative
6 of a long-term outlook for the cost of money.
7 This results in a ROE of 8.56%. The second
8 option is to use six months of market data to
9 smooth/dampen the impact of the most recent
10 data, which results in an ROE of 8.49%. As with
11 the first option, this would recognize that
12 current market information may not be indicative
13 of long-term equity investor expectations and
14 instead of just using the recent three months,
15 the information would be blended with an earlier
16 time period. The third option is to adopt a
17 construct similar to what the FERC has
18 traditionally used in determining its authorized
19 ROEs. Specifically, the FERC has had a long
20 tradition of establishing a DCF "range of
21 reasonableness" to delineate a range of results
22 from the full range of individual proxy group
23 company DCF ROEs. Similarly, the Commission
24 could take Staff's DCF results and determine a

1 reasonable range from which to choose its DCF-
2 specific ROE.
3 Q. Can you illustrate how that approach might work
4 using your DCF results?
5 A. Using our DCF results, the maximum result is
6 11.25% and the minimum result is 6.32%, with a
7 midpoint of 8.78%. Thus, based upon these
8 parameters, a FERC-like "range of
9 reasonableness" would be between 7.55% and
10 10.02%. The Commission could choose a DCF from
11 this range to utilize in conjunction with
12 Staff's CAPM results to arrive at an authorized
13 ROE. Given the fairly broad range of discretion
14 that this approach would afford the Commission
15 to establish the DCF portion of the overall ROE
16 this adaptation would clearly be a significant
17 deviation from Staff's traditional formulaic
18 approach. Lastly, the Commission could continue
19 to use the results from Staff's model with no
20 adjustments (including no change to the use of
21 the mean result in the DCF calculation). This
22 would result in an ROE of 8.13%. The Commission
23 could make positive adjustments to the ROE, the
24 equity ratio, depreciation rates and/or

1 regulatory asset amortizations, if necessary, in
2 order to preserve a utility's financial
3 integrity. Calculating pro forma financial
4 metrics using S&P and Moody's ratios would show
5 if the ROE would be able to maintain an
6 investment grade rating.
7 Q. Did you consider any of those options and what
8 did you do differently in calculating the
9 recommended ROE?
10 A. As we discussed earlier in our testimony, we
11 find that utilizing the mean DCF result was a
12 sufficient change to Staff's traditional
13 methodology in calculating the recommended ROE,
14 as using the median in this situation appears to
15 be suppressing the ROE below what the "average"
16 or "typical" investor in the proxy group would
17 require at this time. Also, Staff's recommended
18 ROE of 8.60% is not far off from most of the
19 alternative options discussed in our testimony.
20 Q. Does your recommended capitalization and cost
21 rates shown on Exhibit__(FP-2) harm the
22 financial integrity of Distribution?
23 A. No. As discussed earlier in our testimony, we
24 calculated several financial ratios that Moody's

and S&P use in determining a credit rating for regulated gas and electric utility. Using our recommended cost rates and capitalization, implies that Distribution would have a comfortable investment grade rating.

CONCLUSION

Q. Should your recommended common equity ratio of 42.3% and ROE recommendation of 8.60% be updated during the course of this proceeding?

A. Yes. As discussed earlier, the common equity ratio should be updated to reflect the most current financial statements available for National Fuel Gas Company, and the ROE estimate should also be updated prior to the Commission's decision to reflect the most current Value Line estimates for the proxy group companies as well as the most recent interest rate data. The necessity of adding additional basis points to the base ROE should also be revisited based upon a comparison of the common equity ratio of the proxy group to that of National Fuel Gas Company. If the Parent's common equity ratio declines further, relative to Staff's proxy group, then perhaps a higher adjustment may be

1 warranted.

2 Q. Does this conclude your testimony at this time?

3 A. Yes, it does.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

National Fuel Gas Distribution Corp.

Case 16-G-0257

September 2016

Prepared Supplemental Testimony of:

Staff Finance Panel

Michael J. Augstell
Principal Utility Financial Analyst
Office of Accounting, Audits and Finance

Vincent Califano
Senior Utility Financial Analyst
Office of Accounting, Audits and Finance

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

Q. Please state your names and business address.

A. Michael Augstell and Vincent Califano. We are employed by the New York State Department of Public Service (Department). Our business address is Three Empire State Plaza, Albany, New York 12223.

Q. Did you also submit Direct Testimony in this proceeding?

A. Yes, we submitted Direct Testimony on behalf of the Department of Public Service in Case 16-G-0257.

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

A. The purpose of our Sur-Rebuttal testimony is to respond to some areas of the Rebuttal Testimony of Ann E. Bulkley and the Rebuttal Testimony of the Company Finance Panel. Our analysis is supported by Exhibit___(FP-24) through Exhibit___(FP-26).

CAPITAL STRUCTURE

Q. With respect to the ratings agencies views on the relative adequacy of the capital structure of National Fuel Gas Company, the Rebuttal Testimony of the Company Finance Panel states,

"No, in our experience, neither S&P nor Moody's uses current or expected capital structure as a significant factor in their evaluations of the Parent's credit rating." Do you agree with this assessment?

A. No. It is apparent that the ratings agencies are much attuned to the degree of leverage and its implications for the exploration and production (E&P) industry. As illustrated in Moody's recent report, Exhibit___(FP-24), "Independent Exploration and Production-North America, No Relief in Sight for Stretched Balance Sheets in 2016," August 23, 2016, there is specific discussion on leverage in the E&P sector. On page 2 of the report it is stated, "Leverage for North American E&P sector remains elevated, despite a modest improvement in oil and natural gas prices, and will not improve before the end of 2016. E&P companies began the current downturn in mid/late 2014 with much higher debt levels and leverage, with today's low commodity prices making development unsustainable for many companies." On page 1 of the report it is also stated, "Companies have

addressed their balance sheets by issuing equity, selling assets, cutting dividends, repaying debt, or some combination of these actions." In short, the capitalization of National Fuel Gas Company is an important factor in Moody's ratings analysis of the Parent.

RING-FENCING

Q. On page 20 of Company Rebuttal witness Reed's testimony he states, "Staff has not identified any problem where the ratepayer has been harmed due to NFG's financial policies, nor is there a hypothetical future problem that may not be addressed with the ratemaking tools already available to the Commission." Do you agree with this statement?

A. No. While at this time it does not appear that Distribution has been harmed by NFG's financial policies, neither Company witness Reed, nor anyone else, can predict with certainty where oil and natural gas prices will be a year or two from now. Accordingly, the Company cannot provide assurances that any of the ratings agencies could downgrade the Parent's credit rating into a non-investment grade rating,

thereby threatening the Company's access to access to reasonably priced capital. Isolating Distribution with the ring-fencing mechanisms recommended in the Staff Finance Panel would help to protect the utility from these risks.

Q. Company witness Reed states on page 17 that, "In my more than 40 years in the industry, I have never seen ring-fencing like this imposed in a rate case." Do you agree with this statement?

A. We cannot confirm such a broad statement which opines as to witness Reed's knowledge; however, in New York State every holding company is a utility holding company with a S&P business risk profile of either "Excellent" or "Strong", except for National Fuel Gas Company, which is not a utility holding company and only has a business risk profile of "Satisfactory". And while imposing ring-fencing via a litigated rate case may not be common, there are multiple instances of such concerns being addressed in joint proposals in New York. The corresponding Moody's and S&P ratings with the risk profiles for the NYS utilities and the respective parents are shown on Exhibit___(FP-25).

REGULATORY RANKINGS

Q. Do Company witness Bulkley's regulatory estimates fall in line with the Commission's actual regulatory rankings?

A. No, Company witness Bulkley's rebuttal testimony on page 70 suggested the Commission's regulatory ranking is below average when in fact her reports and Exhibits__(AEB-10 and AEB-11) confirm the Commission's regulatory ranking is between "Average" to "Above Average".

In Ms. Bulkley's Exhibit__(AEB-10), she references a RRA report, dated March 10, 2016, which ranks NYS Public Commission as "Average" thus, refuting her rebuttal claim that New York regulatory environment is below average.

Additionally, Ms. Bulkley's regulatory review of Utility Regulatory Assessments for U.S. Investor-Owned Utilities (Commissions) by S&P Ratings Services' dated January of 2014, as seen in her Exhibit__(AEB-11), ranks the NYS Public Service Commission in the second highest (2 of 5) ranking category of Strong/Adequate.

Q. What does Regulatory Research Associates (RRA) say about the New York State regulatory

environment?

A. In RRA's "State Regulatory Evaluations", Exhibit___(FP-26), January 22, 2016, it ranks New York's regulatory climate as 'Average' (A/2). RRA has three rating categories; 'Above Average' (AA), 'Average' (A) and 'Below Average' (BA) and three relative positions '1' indicates a stronger, more constructive rating, '2' is a mid-range rating; and '3' is a weaker, less constructive rating. The 'A2' rating indicates that New York's ranking fails in the middle of the rankings, thus, its rank is 'Average'.

Q. Does this conclude your rebuttal testimony at this time?

A. Yes, it does.

A.L.J. LECAKES: All right. I'll take the affidavits now. Okay. So we're at Exhibit 133 for the affidavit of Michael Augstell, A-U-G-S-T-E-L-L, and Exhibit 134 for the affidavit of Vincent Califano, C-A-L-I-F-A-N-O.

A.L.J. LECAKES: And The Finance Panel's exhibits including the ones attached to the original testimony as well as the supplemental testimony?

MR. FAVREAU: Correct. The ones for the original direct testimony are FP1 through 23 and for the supplemental testimony FP24 through 26. We would ask that they be marked for identification.

A.L.J. LECAKES: Okay. So FP1 will be 135, FP2 136, FP3 137, FP4 138, FP5 139, FP6 140, FP7 141, FP8 142, FP9 143, FP10144, FP11 145, FP12 146, FP13 147, FP 14 148, FP15 149, FP16 150, FP17 151, FP18 152, FP19 153, FP20 154, FP21 155, FP22 156, FP23 157, FP24 158, FP25 159, and FP26 160 and Mr. Favreau, you noted that that was the last panel that you have affidavits for?

MR. FAVREAU: That is correct, Your Honor.

A.L.J. LECAKES: UIU?

MR. ZIMMERMAN: Good afternoon. We have witness Greg C. Collar who filed 23 pages of questions and -- questions and answers in his direct testimony. I'd like to note that those questions and answers be entered into the record as if given orally here.

A.L.J. LECAKES: Granted. We'll mark Mr. Collar's affidavit as Exhibit 161 and on the UIU Testimony folder, it will be under the file UIU Collar Direct

Testimony and all that needs to be put into the record at this point is UIU Collar Direct Testimony 16-G-0257. The file that's also on there, Collar Affidavit, does not need to be copied into the transcript; instead, we will treat it as an exhibit.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service.	Case 16-G-0257

DIRECT TESTIMONY

OF

GREGG C. COLLAR

Dated: August 26, 2016
Albany, New York

UTILITY INTERVENTION UNIT
DIVISION OF CONSUMER PROTECTION
NYS DEPARTMENT OF STATE
99 WASHINGTON AVENUE
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ALBANY, NY 12231-0001
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I. INTRODUCTION AND OVERVIEW OF TESTIMONY

Q. Please state your name, title and business address.

A. My name is Gregg C. Collar. I am a Utility Program Analyst with the Utility Intervention Unit (UIU) of the New York State Department of State's Division of Consumer Protection. My business address is 99 Washington Avenue, Suite 640, Albany, New York 12231-0001.

Q. Please briefly summarize your qualifications and employment background.

A. I received a Bachelor of Arts in Mathematics from Hartwick College in 1995. Since March 2005, I have been employed as a Utility Program Analyst, initially with the New York State Consumer Protection Board (CPB), and, beginning in April 2011, with the New York State Department of State's UIU. In this position, I am primarily responsible for analyzing utility low-income and service quality performance measurement programs currently in place and identifying reforms that would enhance their reach and effectiveness. I research and draft formal documents advocating UIU's position in Public Service Commission (PSC or Commission) proceedings and represent UIU in collaborative proceedings, negotiations and other meetings advocating for low-income programs, service quality performance issues and other matters of interest to UIU. I serve as UIU's representative to the Low-Income Forum on Energy and the Natural Gas Reliability Advisory Group, and UIU's representative and Chairperson on the Board of Directors of the telecommunications Targeted Accessibility Fund, which oversees public benefit programs including Lifeline and E911.

I participated as UIU's representative in Case 01-M-0075, which examined National Grid-Upstate's low-income assistance program, as well as in a collaborative in Cases 05-E-0934 and 05-G-0935 that addressed Central Hudson Gas & Electric Corporation's (Central Hudson) low-income program. I also conducted research and drafted documents pertinent to UIU's participation in the investigation of the July 2006 electric power outage of Consolidated Edison of New York Inc.'s (Con Edison) Long Island City Electric Network, Case 06-E-0894, and the investigation of the prudence of Con Edison regarding the July 2007 steam pipe rupture in Case 08-S-0153. In Case 07-M-0548, the proceeding regarding the Energy Efficiency Portfolio Standard (EEPS), I served as the UIU representative in the working group related to the establishment of natural gas efficiency goals and the working group assigned to help customers overcome barriers to energy efficiency with the potential use of an on-bill financing program. I also served as the UIU participant in the EEPS Evaluation Advisory Group. Most recently, I have been involved in Case 14-M-0101, the Reforming the Energy Vision (REV) proceeding, and in Case 14-M-0565, the proceeding addressing affordability for low income customers (Affordability Proceeding).

Q. Mr. Collar, have you previously testified and/or been involved in negotiations in PSC proceedings?

A. Yes, I have submitted testimony in many rate proceedings involving Con Edison, Cases 08-E-0539, 09-G-0795, 09-E-0428, and 13-E-0030/13-G-0031; Orange and Rockland Utilities, Inc., Cases 08-G-1398, 10-E-0362, 11-E-0408 and 14-E-

0493/14-G-0494; Central Hudson, Cases 09-E-0588/09-G-0589, 12-M-0192 and 14-E-0318/14-G-0319; New York State Electric and Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E), Cases 09-E-0715 *et. al* and 15-E-0283 *et. al*; Corning Natural Gas Corporation, Case 11-G-0280; and National Grid-Upstate, Cases 10-E-0050 and 12-E-0201/12-G-0202. Most recently, I submitted testimony in the rate proceedings of KeySpan Gas East Corp. dba Brooklyn Union of L.I. (KEDLI) and The Brooklyn Union Gas Company dba National Grid NY (KEDNY), Cases 16-G-0058 and 16-G-0059, and of Con Edison in Cases 16-E-0060 and 16-G-0061. In addition to these electric and gas rate case proceedings, I also submitted direct and rebuttal testimony in Case 09-M-0527, a proceeding that established a State Universal Service Fund, which is intended to ensure local telephone service remains universally available throughout New York State. Additionally, while I did not submit testimony, I represented and advocated the UIU's positions in the recent applicable rate plan or rate plan extension proceedings for KEDNY in Case 12-G-0544, Corning Natural Gas Corporation in Case 11-G-0280, and National Fuel Gas Distribution Corporation (NFG of the Company) in Case 13-G-0136.

Q. What is the purpose of your testimony?

A. I will discuss — and make recommendations regarding — the Company's Service Quality Performance Mechanism (SQPM), Low Income Program, the documentation required for a prospective customer to open a new account, and new Customer Information System (CIS).

Q. Please summarize your recommendations

A. I discuss the following recommendations in my testimony:

1) UIU recommends the Commission reject the Company's proposal to discontinue its SQPM.
2) UIU proposes to eliminate two of the eight service metrics that make up the current SQPM, and to adopt more stringent targets for the six remaining metrics.
3) UIU proposes a modification to the Negative Revenue Adjustments (NRAs) associated with each service metric under the SQPM and how they are calculated.
4) UIU proposes that the Company's low income programs continue as currently structured at least until the resolution of petitions for rehearing filed in the Affordability Proceeding.
5) UIU proposes enhanced low income program reporting requirements.
6) UIU proposes that the Company accept an Individual Taxpayer Identification Number (ITIN) in lieu of a Social Security Number as a form of personal identification and also proposes that the Company look further into other forms of identification to be made acceptable for this purpose.
7) UIU proposes that a measure of savings attributed to the Company's proposed new CIS be passed back to customers.

Q. Are you sponsoring any exhibits associated with your testimony?

A. Yes, I am sponsoring two exhibits. Exhibit __ (GCC-1) consists of the Company's responses to Information Requests (IRs) that I relied upon in

preparing this testimony. Exhibit __ (GCC-2) depicts my recommendations regarding the SQPM compared to the one currently in place.

II. SERVICE QUALITY PERFORMANCE MECHANISM

Q. What is the function of SQPMs?

A. SQPMs help to ensure the delivery of high-quality customer service. Quality service is important to customers and is in the public interest. Due to the monopolistic nature of utility service, customers cannot select another delivery service provider if they are unsatisfied with the quality of service they receive from the Company. Meaningful measures associated with appropriate financial risk are required to ensure that utility companies provide adequate service to their customers. Structured correctly, SQPMs provide utilities with powerful incentives that should result in the level of service to which customers are entitled.

Q. Please describe the Company's current SQPM.

A. The Company's SQPM currently comprises eight service quality performance metrics: Appointments; New Service Installations; Residential Satisfaction; Non-Residential Satisfaction; PSC Complaints; Telephone Response (percentage of calls answered within thirty seconds); Adjusted Bills; and Estimated Meter Readings. The NRAs at stake range from $200,000 to $1,500,000 and are assessed based on the total number of "units" incurred by the Company. (See Exhibit _ (GCC-2))

Q. How has the Company performed under the SQPM?

A. The Company's Customer Service Panel (Panel) indicates on page 14 of its direct testimony that the Company has met all of its service quality performance metrics and has never incurred an NRA.

Q. Does the Company propose to continue its SQPM?

A. No. The Company proposes to discontinue the SQPM in its entirety.

Q. What reasons does the Company give for its proposal to discontinue the SQPM?

A. The Company provides two reasons: first, that the SQPM is not needed to ensure good customer service, and second that the SQPM is a "purely punitive measure," and as such, "the Company has serious reservations as to whether a punitive arrangement as the SQPM can lawfully be imposed under the existing statutory and regulatory scheme." (Panel p. 14.) The Company further articulated this second argument in its response to UIU IR No. 32 which reads in part:

> Upon advice of counsel, there is no basis in law for SQPMs, nor does the Commission have authority to impose them. Furthermore, SQPMs have not been proven to be necessary for a utility to provide good customer service and, in fact, the Company has continued to provide excellent customer service even in the absence of SQPM penalty metrics. If the Commission were of the belief that customer service standards were necessary, it would have issued the customer service regulations that it proposed more than a quarter of a century ago.

Q. What is the UIU's reaction to the Company's proposal to discontinue its SQPM?

A. UIU strongly disagrees with this proposal. As discussed earlier, the quality of service a company provides is a critical aspect of that service, particularly when

the service is essential, such as the supply of gas to the home. The market forces that incent non-monopoly firms to maintain high levels of service quality are largely inapplicable to monopoly utilities. SQPMs are a technique that helps to fill this gap by connecting the utility's earnings to its customer service quality. SQPMs help to ensure that utilities provide customers with the level of service to which they are entitled, and thus serve the public interest.

Despite the Company's assertions to the contrary, the Commission has long supported customer service standards as appropriate and necessary. In 1992, the Commission required major utilities to record and submit to the Commission metrics on customer service quality performance (see Case 91-M-0500, Order Directing Utilities to Supply Service Data, issued January 16, 1992), and subsequently approved customer service quality metrics across New York utilities, including the Company's SQPM in 2005 (see Case 04-G-1047, Order Establishing Rates and Terms of Two-Year Rate Plan, issued July 22, 2005).

Q. Has the Company proposed eliminating its SQPM in the past?

A. Yes, the Company made this proposal in a prior rate proceeding, Case 07-G-0141.

Q. Did the Commission comment upon, or make any rulings regarding, such proposal?

A. Yes. The Commission rejected the Company's proposal. On page 44 of its December 21, 2007 Order Establishing Rates for Gas Service, the Commission

wrote:

> NFG's position that we should simply abandon the use of safety and service targets and incentives is untenable and unacceptable. This approach to safety and service quality is both practical and a proper use of Commission authority to ensure that safe and reliable service is maintained by the utility company as the foremost aspect of its responsibilities to the public. We have authority to reduce rates of return to reflect poor service quality. We have approved incentive programs in the context of accepting multi-year rate plans as "just and reasonable." We can index portions of the Company's return for the rate year in this case to achievement of key measures of safety and service quality. Contrary to the Company's claims, linkage of rates of return to fully achievable levels of acceptable performance is not a "penalty," but a lawful exercise of our authority to set "just and reasonable" rates.

Q. Is the 2007 Commission Order's discussion of the Company's SQPM consistent with other Commission proceedings, and/or other utilities' rate plans?

A. Yes, in addition to this Commission Order, there are several such examples demonstrating that service quality performance incentives are important.

Q. Please discuss these examples.

A. First, to the best of my knowledge and belief, every major electric and gas utility has had similar customer service quality mechanisms in place at least since I joined the CPB in 2005. I am not aware of any other utility that has proposed to discontinue its respective service quality performance incentive mechanism during that time.

Generic proceedings also indicate the importance of SQPMs. In Case 13-M-0314, *Issue a Request for Proposal for an Independent Third-Party Consultant to Conduct a Review of the Accuracy and Effectiveness of Certain Reliability and*

Customer Service Systems at all Gas and Combination Gas and Electric Utilities in New York State that Provide Statistics to the Commission on the Services They Provide Customers, the Commission instructed an independent third-party consultant to conduct an audit of the accuracy of the self-reported data regarding electric reliability, gas safety and customer service provided by the state's major electric and gas utilities. In Case 15-M-0566, *In the Matter of Revisions to Customer Service Performance Indicators Applicable to Gas and Electric Corporations,* the Commission approved a final audit report, whose customer service portion made 576 findings and 228 recommendations, including supporting the ongoing use of SQPMs. (Order Releasing Report and Providing Guidance On Response, issued April 20, 2016, pp.14-16.)

The Commission's Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, issued May 19, 2016 in the REV proceeding, also reflects the importance of customer service quality incentive mechanisms, including their usefulness in other states as well as New York. Page 7 of that Order reads in part, "New York and many other states have used performance incentives for years to encourage reliability, customer service, and other priorities. Performance incentives are a useful tool in a cost-of-service ratemaking context." The Commission further observed on page 58 of the Order that these performance incentives or standards "have a deterrent effect against poor service" and "there is little controversy over the success of these standards and the merit of retaining them." These proceedings demonstrate both the Commission's commitment to SQPMs to ensure that customers receive

adequate service, as well as the effectiveness of SQPMs in advancing this objective.

Q. Do you have a reaction to the Panel's assertion that "there is no basis in law for SQPMs, nor does the Commission have authority to impose them"?

A. I cannot comment on the merits of this assertion, because I am not an attorney and because the Company's Panel provided no additional support or discussion. I do note, however, that the Company raised legal objections to the SQPM in its 2007 rate case, Case 07-G-0141, which the Commission rejected. (*See* Order Establishing Rates for Gas Service at pp.43-44.)

Q. What are UIU's other recommendations regarding the Company's SQPM?

A. UIU proposes to establish stricter SQPM service target levels for six of the eight metrics (Residential Satisfaction, Non-Residential Satisfaction, PSC Complaints, Telephone Response, Adjusted Bills, and Estimated Meter Readings), and eliminate the remaining two metrics (Appointments and New Service Installations).

Q. Why do you propose stricter service target levels for those six metrics?

A. The Company has met each of those targets over the course of its current rate plan. Customers deserve to see their utility's performance improve over time, especially where, as here, the utility asks its customers to pay higher rates. SQPM targets should therefore be set at levels that challenge utilities to achieve

enhanced customer service, rather than staying with the status quo. A target that a Company has no trouble meeting fails to adequately incent the Company to improve its performance.

Q. Where are your proposed targets for these six service metrics presented?

A. They are presented in Exhibit _ (GCC-2).

Q. How did UIU determine its proposed targets for the six service metrics?

A. These proposed new targets are based on the Company's five-year average performance plus/minus two standard deviations. This provides an adequate range around the Company's five-year average before the Company would incur a NRA. This is an appropriate level to ensure that the Company continues to improve the service quality its customers deserve.

Q. Please discuss the current proposed targets associated with each of the six service metrics.

A. Under the current target for the Residential Satisfaction service metric, the Company does not incur a NRA until its performance falls below the threshold level of 85.1%. UIU recommends increasing this threshold to 91.3% based on a five-year average of 93.1%. Adjusting the minimum threshold to 91.3% correlates to a maximum threshold of 85.2%, as shown in Exhibit _ (GCC-2).

Under the current target for the Non-Residential Satisfaction service metric, the Company does not incur a NRA until its performance falls below the

threshold level of 86.0%. UIU recommends increasing this threshold to 89.1% based on a five-year average of 91.0%. Adjusting the minimum threshold to 89.1% correlates to a maximum threshold of 79.1%, as shown in Exhibit _ (GCC-2).

For PSC Complaints, under the current target, the Company does not incur a NRA until it exceeds a threshold of 2.1 complaints per 100,000 customers. UIU recommends the Commission lower this threshold to 0.1 complaints per 100,000 customers, based on the Company's five-year average of 0.0 complaints. Based on the proposed adjustment to the minimum threshold, the Company would become subject to the maximum NRA if it exceeds 1.5 complaints. (See Exhibit _ (GCC-2)).

UIU recommends adjusting the target for Telephone Response to 86.2%. Under the current target, the Company does not incur a NRA until its performance falls below the threshold level of 74.0%. UIU's recommended increase to this target is based on the Company's five-year average performance rate of 90.6%. Based on the proposed adjustment to the minimum threshold, the Company would become subject to the maximum NRA if its performance falls below 78.2%. (See Exhibit _ (GCC-2)).

UIU recommends lowering the target for Adjusted Bills from 1.9% to 1.4%, based on the Company's five-year average performance rate of 0.9%. This adjustment to the minimum threshold also adjusts the maximum threshold from 3.5% to 3.0%. (See Exhibit _ (GCC-2)).

UIU has a similar recommendation for Estimated Meter Readings. UIU

proposes lowering the target from 15.9% to 13.4%, based on the Company's five-year average of 10.3%. This adjustment to the minimum threshold also adjusts the maximum threshold from 24.0% to 21.5%. (See Exhibit _ (GCC-2)).

Q. Do you have other recommendations related to the Company's SQPM?

A. Yes. As mentioned earlier, UIU proposes to eliminate the Appointments and New Service Installations service metrics. The Company's five-year average performance for each of these service metrics is close to 100% - 99.1% and 99.9% for Appointments and New Service Installations, respectively. The Company's excellent historic performance with respect to these two service metrics indicates that they do not represent areas of significant concern, and therefore the Company should focus on improving other aspects of its customer service quality.

However, there is still value in ensuring that the Company keeps its appointments with customers when conducting non-emergency work. Therefore, in place of the Appointments service metric, UIU proposes that the Company credit a customer $30 when it fails to keep a scheduled appointment with a customer. This performance mechanism is similar to ones implemented by other gas utilities, including Central Hudson and Niagara Mohawk, and imposes minimal risk on the Company while meaningfully recognizing the importance of maintaining customer appointments.

Q. How should the revenue currently at risk under the Appointments and New

Service Installations service metrics be allocated?

A. UIU proposes that the full revenues ($1,500,000 annually) currently at risk among the eight current SQPM service metrics be reallocated amongst the remaining six metrics following the elimination of the Appointments and New Service Installations service metrics. Exhibit __ (GCC-2) details this proposed reallocation.

Q. Does UIU have further recommendations related to the Company's SQPM?

A. Yes. UIU proposes that for each service quality metric, the NRA amounts associated with each target threshold level should mirror those of other electric and gas utilities' SQPMs. The Company's current SQPM has five threshold levels within each service quality metric, with a "unit" amount associated with each threshold level. The possible "units" that can be achieved based on the Company's performance range from 0 to 126 within each service quality metric. The Company would become subject to a NRA ranging from $200,000 to $1,500,000 depending on the total number of "units" it accumulates amongst all the service quality metrics. The Company's response to UIU IR No. 30 details the breakdown of the total "units" and accompanying NRAs.

UIU believes that this method for calculating NRAs is inappropriate, as it allows the Company to miss its service quality targets without incurring an NRA. For example, under the current SQPM, the Company incurs 25 "units" if it fails to meet the first threshold target level of a service metric. But the Company does not incur an NRA until it reaches 126 "units." The Company could thus miss five

service quality metrics at the first threshold level, and incur 125 "units," without incurring an NRA. This method therefore effectively makes the service level targets more lax than they initially appear, and is not consistent with other utilities' SQPMs.

UIU's proposal would align the Company's SQPM with those of other New York utilities. UIU's proposed method would make the Company subject to an NRA for <u>each</u> of the targets it misses, providing a clearer, more consistent incentive to the Company to provide adequate service. Exhibit _ (GCC-2) details UIU's proposed NRA amounts for the threshold levels for each of the service metrics.

III. LOW INCOME PROGRAM

Q. Please describe the low income program the Company currently offers its customers.

A. The Company's gas low income program consists of various programs and services. At present, the Company offers the Home Energy Assistance Program (HEAP), Residential Assistance Service (HRAS), Low Income Customer Affordability Assistance Program (LICAAP), Low Income Usage Reduction Program (LIURP), Elderly, Blind, and/or Disabled Heating Equipment Repair/Replacement (EBD HERR), and HEAP HERR programs for customers who are HEAP customers only.

HRAS is a broad-based program that provides a flat $12.50 discount per month for the months of January – May. LICAAP is a more targeted program

that provides a higher level of benefit and provides program participants the opportunity for complete arrearage forgiveness. Under this program, 1/24 of a customer's arrears balance is forgiven each month when payment of the reduced budgeted-bill is made on time. LICAAP eligibility is based on household income and size. LIURP is a weatherization program for eligible low income customers and is administered as part of New York State Energy Research and Development Authority's EmPower program. Program participants receive various services including heating system checks, energy audits, consumer education, and installation of weatherization and energy efficient services. The EBD HERR and HEAP HERR programs are available to HEAP customers who have a "No-Heat" situation and a need to repair or replace their heating equipment. The Company's response to UIU IR No. 4 provides a more detailed description of these programs and services.

Q. Does the Company propose any changes to the current low income program?

A. The Panel's filed direct testimony proposed the following changes: (1) extend the $12.50 monthly discount for HRAS program participants for an additional three months (i.e., from October through May); (2) continue the LICAAP program with a slight change that allows the Company to transfer LICAAP customers who are no longer eligible for arrearage forgiveness to HRAS program; (3) increase the revenue requirement associated with EBD HERR program by $10,000 for a total of $420,000; and (4) implement a reconnection fee waiver program, which would provide one waiver of reconnection charges per year to those low income

customers whose service is terminated for nonpayment and later reconnected.

However, the Company made these proposals prior to the issuance of the Commission's Order Adopting Low Income Program Modifications and Directing Utility Filings (Low Income Order) issued May 20, 2016 in Case 14-M-0565. As I discuss later in my testimony, the Company's implementation of the Low Income Order may include significant deviations from its recommendations in testimony.

Q. Please discuss the Low Income Order.

A. The Low Income Order establishes a unified statewide approach to utility low income programs, and prescribes several changes to utilities' current programs. The Low Income Order directed each utility to file a document describing how it will implement the Low Income Order by August 18, 2016. The Commission subsequently extended the deadline for these implementation plans to September 16, 2016. As of the filing of this testimony, the Company has not filed its implementation plan. On June 10, 2016, Company's Low Income Panel filed supplemental direct testimony and Exhibit ___ (LIOP-1), which provided an analysis of the costs associated with implementing the Low Income Order.

The Low Income Order itself declines to resolve all matters related to the Company's low income programs. Instead, several low income-related matters are left to be determined in rate proceedings, including discount design details, the specific method of cost recovery, and whether and how to implement arrearage forgiveness and/or reconnection fees.

Furthermore, the requirements of the Low Income Order may be subject to

change in the future. Several parties, including the Company, have filed petitions for rehearing and/or clarification on the Low Income Order. The petitions addressed several issues associated with the Low Income Order, including but not limited to, eligibility for utility benefits; the applicability of the Low Income Order; how utility discount programs should conform to the Low Income Order; and utility budget limitations as compared to energy burden levels. As of the filing of this testimony, the Commission is accepting public comments on these petitions, but has not otherwise acted to resolve the concerns they raise.

Q. Given that the Low Income Order does not resolve all low income-related matters, and the petitions for rehearing are still yet to be resolved, are there aspects of the Company's low income program you would like to discuss here?

A. Yes. UIU recommends that the bulk of the Company's current low income programs, especially HRAS and LICAAP, remain in place until outstanding questions regarding the Low Income Order have been resolved. The Company should avoid premature implementation of the Low Income Order, which could lead to duplicative or wasteful efforts on the part of the Company.

Q. Do you recommend any changes to the Company's low income programs to take effect prior to its implementation of the Low Income Order?

A. Yes. UIU applauds the Company's initial proposal to extend the current $12.50 monthly discount for participants in the HRAS program from five months to eight. UIU proposes that this discount be extended to the entire 12 months of the year.

Additionally, this discount should account for rate increases. UIU proposes that the monthly bill credit for low income program participants in HRAS should increase by the same percentage amount as any increases to delivery rates approved by the Commission in this rate case to ensure that low income customers are adequately protected.

UIU supports the Panel's proposal to implement the once per year reconnection fee waiver for those low income customers deemed eligible. Implementing the waiver aspect of the Company's low income program provides uniformity among New York utilities' programs.

Q. Is there another proposal you would like to discuss?

A. Yes. Regardless of the ultimate outcomes in the Affordability Proceeding, the Company should implement the enhanced reporting requirements described in Appendix D of the Low Income Order. As the Commission observed on page 39 of the Low Income Order, "low income program reports currently filed by the utilities do not provide sufficient information to compare different program approaches, identify best practices, or gauge program effectiveness." The Company's responses to UIU IRs Nos. 8, 14, and 16 demonstrate that the Company does not currently track some of the data included in Appendix D of the Low Income Order. These data would be helpful in determining the effectiveness of the Company's low income programs. Additionally, no party that filed petitions for rehearing of the Low Income Order objected to Appendix D's data reporting requirements.

IV. SERVICE APPLICATIONS

Q. What documentation does the Company require for a prospective residential customer to open a new account?

A. According to the Company's responses to UIU IRs Nos. 23 and 24, the Company asks prospective residential customers to provide a social security number. Customers may choose instead to provide two forms of identification, one of which must contain a picture.

Q. What is ITIN?

A. According to the Internal Revenue Service's website, "an [ITIN] is a tax processing number issued by the Internal Revenue Service. The IRS issues ITINs to individuals who are required to have a U.S. taxpayer identification number but who do not have, and are not eligible to obtain a Social Security Number (SSN) from the Social Security Administration (SSA)."

Q. What do you propose with respect to ITINs?

A. I propose that the Company accept ITINs in lieu of SSNs as acceptable forms of identification for the purpose of opening accounts. This will ensure that a New Yorker who may not have a social security number can nevertheless gain access to gas service. This proposal concerning ITINs is consistent with the Commission's Order approving a Joint Proposal in the most recent NYSEG and RG&E electric and gas rate plan proceedings (Cases 15-E-0283 et. al.).

I also recommend that the Company consider other forms of identification

that may be made acceptable for this purpose, including: Consular Identification cards; unexpired U.S. or foreign passports; unexpired Employment Authorization Documents that contain a photograph; Uniformed Services Identification Cards; U.S. Military Identification Cards; U.S Coastguard Merchant Mariner Cards; Federal Government Personal Identity Cards (PIVs); Department of Defense Common Access Cards; or unexpired driver's licenses issued by a state or Territory of the U.S. or Canada, provided they contain a photograph and information including the name, date of birth, gender, height, eye color and address.

V. CUSTOMER INFORMATION SYSTEM

Q. What is the CIS?

A. The CIS is an application that supports the different data aspects related to the Company's customer service functions, including meter reading, payment processing, billing, collections, and special assistance programs including HEAP. The Company implemented the CIS in 1990, which it replaced with a new Barcelona CIS system in May 2016.

Q. Why did the Company replace the CIS?

A. In his Direct Testimony, Company witness Patrick T. Boyle lists several reasons. They include: 1) the cumulative impact of system changes over the past 22 years; 2) legacy technology issues; 3) outdated and restrictive data models; 4) the obsolescence of paper-based workflow; 5) the inability to obtain customer

data in a timely manner; 6) inability to find the required skillsets to maintain the system; and 7) reduced leverage in negotiating annual software maintenance fees. (Direct Testimony of Patrick T. Boyle at pp. 7-8.)

Q. What was the cost of this new Barcelona CIS?

A. According to the Department of Public Service Staff (Staff) IR No. 212, the Company's new Barcelona CIS cost approximately $38 million.

Q. Has the Company identified any savings and/or benefits associated with the new Barcelona CIS?

A. Yes. Mr. Boyle lists expected "benefits" from replacing the CIS at several points in his direct testimony. These anticipated benefits include: (1) streamlining the Company's workflow and assisting with regulatory compliance (pp. 13-15); (2) incurring fewer maintenance difficulties (pp. 16-17); (3) improving worker productivity (p. 17); and (4) enhancing the Company's "leverage in negotiating contracts for additional software and/or services" from consulting firms" (pp. 17-19). This suggests that the Company expects to realize significant financial benefits as a result of installing the Barcelona CIS.

Q. Does the Company intend to share these benefits with customers?

A. No. According to the Company's response to Staff IR No. 212, "there are no savings and/or benefits associated with the new CIS reflected in the RYE 3/31/2018 forecast." In other words, the Company has not reduced its requested

rate increase to account for the apparent savings it will realize from the Barcelona CIS.

Q. What does UIU recommend with respect to the costs and benefits of the new Barcelona CIS?

A. Ratepayers are being asked to pay for the Barcelona CIS, and should therefore share in the benefits it will yield, especially in light of its high cost. This may take the form of a higher productivity adjustment, reductions in operations and maintenance costs, implementation of a Company/customer benefit sharing mechanism, and/or some other techniques.

Q. Does this conclude your testimony at this time?

A. Yes.

A.L.J. LECAKES: Were there any additional exhibits attached to Mr. Collar's testimony?

MR. ZIMMERMAN: Yes, he had two exhibits labeled GCC1 and GCC2.

A.L.J. LECAKES: GCC1 will be marked for identification as Exhibit 162. GCC2 will be marked for identification as Exhibit 163 and for the UIU Panel, are those separate affidavits?

MR. ZIMMERMAN: Yes, Your Honor, we have a separate affidavit for each of the members of that panel.

A.L.J. LECAKES: Okay.

MR. ZIMMERMAN: So that the UIU Rate Panel consists of Ben Johnson and Danielle Panko. They filed direct testimony consisting of 40 pages of questions and answers and rebuttal testimony consisting of 16 pages of questions and answers. I'd like to move that they be admitted into the record as if given orally here.

A.L.J. LECAKES: Granted. At this point in the transcript, the file UIU Gas Rate Panel Direct Testimony should appear and then followed by the UIU Gas Rate Panel Rebuttal Testimony and those are located in the folder UIU Gas Rate Panel Direct Testimony and Affidavit. The two affidavits that appear on the disk do not need to be copied into the record. The affidavit from Danielle

Panko, P-A-N-K-O, will be marked as Exhibit 164 and the affidavit from Ben Johnson, J-O-H-N-S-O-N, will be marked as Exhibit 165.

*Insert Testimony of UIU Gas Rate Panel (Panko & Johnson)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service.	Case 16-G-0257

DIRECT TESTIMONY

OF

UIU RATE PANEL

Dated: August 26, 2016
Albany, New York

UTILITY INTERVENTION UNIT
DIVISION OF CONSUMER PROTECTION
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I. INTRODUCTION AND OVERVIEW

Q. Would the Panel please state their names and business addresses?

A. **(Johnson)** My name is Ben Johnson, and my business address is 5600 Pimlico Drive, Tallahassee, FL 32309.

(Panko) My name is Danielle M. Panko, and my business address is 99 Washington Avenue, Suite 640, Albany, NY 12231.

Q. By whom are you employed, in what capacity, and what are your professional backgrounds and qualifications?

A. **(Johnson)** I am employed as a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation. I received a Bachelor of Arts degree in Economics from the University of South Florida, and both a Master of Science in Economics and Doctor of Philosophy in Economics from Florida State University.

Over the course of more than 40 years, I have been actively involved in more than 400 regulatory dockets, involving electric, natural gas and other utilities. I have presented expert testimony on more than 250 occasions, before federal regulatory agencies, various state courts, and regulatory commissions in 40 states, two Canadian provinces and the District of Columbia.

The majority of this work has been performed on behalf of regulatory commissions, consumer advocates, and other government agencies involved in regulation, but our firm has worked for other types of clients as well, including

large industrial consumers and non-profit entities like the AARP and the North Carolina Sustainable Energy Association.

(Panko) I currently hold the position of a Utility Analyst with the Utility Intervention Unit ("UIU") of the New York State Department of State's Division of Consumer Protection. I received a Bachelor of Science in Mathematics from the State University of New York at New Paltz in 2001 and a Master of Science in Electrical Engineering from the State University of New York at New Paltz in 2008.

From 2000 to 2001, I served as an intern with Central Hudson Gas and Electric Corporation ("Central Hudson") located in Poughkeepsie, New York, in the Accounts Service Department and subsequently in the Electrical Engineering Department. From 2004 to 2007 I worked as a reliability engineer for Philips Semiconductors. From 2007 to 2012, I worked for Consolidated Edison Company of New York, Inc. ("Con Edison") in the Rate Engineering Department as an Analyst, and later a Senior Analyst, in the Gas Rate Design Section. I joined the UIU in 2012. My primary responsibilities include assisting with UIU's participation in Public Service Commission ("PSC" or "Commission") proceedings, researching utility policy and regulatory related issues, and representing UIU during various utility-related meetings and rate case negotiations. Recent gas cases that I have worked on include Cases 16-G-0061, 16-G-0058, 16-G-0059, 15-G-0284, 15-G-0286, 14-G-0319, and 13-G-0031, in addition to over a dozen other rate and policy proceedings.

Q. Have you previously testified before the Commission?

A. **(Johnson)** Yes. I previously submitted testimony in Cases 13-E-0030 and 13-G-0031 involving Con Edison, in Cases 14-E-0493 and 14-G-0494 involving Orange and Rockland Utilities ("O&R"), in Cases 15-E-0283 and 15-G-0284 involving New York State Electric & Gas Corporation ("NYSEG"), Cases 15-E-0285 and 15-G-0286 involving Rochester Gas and Electric Corporation ("RG&E"), 16-G-0058 and 16-G-0059 involving Keyspan Gas East Corporation d/b/a National Grid ("KEDLI") and Brooklyn Union Gas Company d/b/a National Grid ("KEDNY"), and Cases 16-E-0060 and 16-G-0061 involving Con Edison.

(Panko) Yes. I previously submitted testimony in Cases 13-E-0030, 13-G-0031, 14-E-0318, 14-G-0319, 14-E-0493, 14-G-0494, 15-E-0283, 15-G-0284, 15-E-0285, 15-G-0286, 16-G-0058, 16-G-0059, 16-E-0060, and 16-G-0061.

Q. What is the nature of this testimony?

A. We will primarily focus on the Embedded Cost of Service ("ECOS") study prepared by National Fuel Gas ("NFG" or "the Company") and certain aspects of the Company's rate design. While our testimony is focused on these particular topics, we reserve the right to respond to testimony filed by other parties concerning other topics. Furthermore, the absence of discussion in this testimony should not be construed as support for, or opposition to, the Company's position.

Q. How is your testimony organized?

A. Our testimony has five sections. This first section is an introduction to the forthcoming testimony. In the second section, we briefly summarize our recommendations. In the third section, we briefly discuss the background of this current proceeding. In the fourth section, we discuss the theory and methodologies applied to gas ECOS studies. We recommend an alternative cost of service approach, which gives 100% weight to the demand placed on the system by each customer class in allocating the cost of distribution mains, thereby more appropriately allocating costs amongst customers of various sizes and types. In the fifth section, we discuss the Company's current and proposed delivery rates. We also offer some recommendations to improve the Company's rate design by providing better price signals, more effectively advancing New York State's public policy goals, and providing a better opportunity for customers to take control of their natural gas bill.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes, Exhibit __ (URP-1) accompanies our testimony.

Q. Would you please describe this Exhibit?

A. Yes. Exhibit ___ (URP-1) contains three schedules. Schedule 1 (page 1 of 2) displays the results of the Company's ECOS Study Rate of Return ("ROR") for each Service Classification ("SC"). Page 2 of 2 of the same schedule displays the results of the Company's ECOS model modified to classify gas distribution mains in FERC Plant Account 376 as 100% demand-related. Schedule 2

compares our estimate of customer costs to the Company's current and proposed customer charges. Schedule 3 displays a distribution analysis of the number of customers and usage levels in January and July for residential and low income customers.

II. SUMMARY OF RECOMMENDATIONS

Q. Would you please briefly summarize your recommendations?

A. Our recommendations, presented in the order in which they are discussed in our testimony, are as follows:

Cost of Service

We recommend the Commission reject the Company's proposed method of allocating the costs of gas distribution mains (FERC Plant Account 376) in its ECOS study. The method the Company used allocates an excessive share of these costs onto lower-usage customers. Instead, we recommend these costs be allocated based upon the demand placed on the distribution system by each customer class. This alternative approach has been used by many other utilities around the country, and has been proposed by DPS Staff in other gas rate cases in New York.

Rate Design

We offer some suggestions for the Commission's consideration concerning how rate design can advance the public interest; move in the direction of public policy goals in New York State; and provide long-term incentives for customers to install more insulation and invest in more energy efficient gas heating systems, hot water heaters, and appliances. At a minimum, we believe customer charges for residential and small commercial customers should not increase. In addition, the volumetric declining block rate structure for these customers should gradually be flattened. To mitigate the degree to which this flattening will increase bill volatility for heating customers, while still achieving the goal of improving price signals, we recommend introducing a seasonal rate structure, which retains a somewhat more steeply declining block rate structure during the months of January through March, while flattening rates to a greater degree during other months.

III. BACKGROUND

Q. Please provide background information concerning the Company's rate filing as it relates to your testimony.

A. The Company proposes to increase delivery gas rates by $41.7 million (based on a Return on Equity ("ROE") of 10.2% and an overall ROR of 7.81% on projected rate base), which would be its first base rate increase since 2007. This revenue increase is estimated to increase customers' delivery bills by approximately 7.89% (based upon overall revenues from firm services, excluding the cost of

gas) during the rate year. If the Company's proposals are accepted, most residential customers would see their bill increase by a similar magnitude, with some exceptions. For instance, SC-1 Aggregated Transportation would experience a much larger percentage increase of 14.7%, while SC-2 low income residential sales and transportation services would experience a much lower percentage increase of 3.3%.

The requested rate changes would impact approximately 514,845 NFG gas customers (according to the customer breakdown found in the June 2, 2016 NFG Technical Conference Presentation) in 14 Western New York counties. Approximately 480,000 (93%) are residential accounts, including 411,927 Residential Heating and Non-heating customers in SC-1, 117 Elderly, Blind or Disabled ("EBD") customers in SC-2A, 58,097 HEAP Residential Assistance Service ("HRAS") customers in SC-2, and 9,901 LICAAP in SC-2B. These residential customers are responsible for about 50% of the Company's gas deliveries and 77% of the Company's revenues. The majority of the remaining accounts are commercial customers in General SC-3 (33,864 customers or approximately 7%). The Company also serves a small number of other types of customers.

IV. COST OF SERVICE

A. Background

Q. Before going into depth on cost of service issues, would you provide a few brief introductory comments concerning the Company's ECOS study?

A. Yes. An ECOS study is often developed in rate proceedings for potential use in determining how to allocate the revenue requirement across classes (often referred to as "revenue allocation") and in developing various gas rate design proposals.

In the first major step of an ECOS study – called "functionalization" – costs are organized based upon various operating functions (e.g., transmission, distribution system, production, storage, and other costs). In the second major step – called "classification" – costs are grouped into classifications: demand or capacity related, energy or commodity-related, customer-related. Some costs might also be classified as revenue-related. The third major step – called "allocation" – is where specific data are selected and used to allocate costs to specific groups of customers. This step involves the development and application of various percentage factors to spread costs to particular customer classes and rate schedules. The allocation factors are derived from several sources of data and tend to closely track the initial decisions concerning how costs are functionalized and classified.

Although the general mechanics of the process used to develop an ECOS study are well-established and are not controversial, the results will vary widely

depending upon specific judgments that are made during the classification and allocation process – judgments which have been the subject of much debate and controversy throughout the last 40 years, if not longer.

The initial functionalization step tends to be the least controversial part of the process. The second step, classification, is where much of the controversy is often centered because there are only a limited number of classification options, and the causal relationship between specific costs and the available classifications may be tenuous. The next step, allocation, also can be controversial, because the impacts of disputed judgments made during the second step tend to show up during the final step, and because a variety of different peak allocation factors can be chosen to allocate demand-related costs.

In this proceeding we dispute the Company's decision to classify the costs of distribution mains (Account 376) as partially "customer related" and partially "demand related," as well as the specific percentage split which it used for this purpose. The Company used a "zero-intercept" analysis to decide that it would classify 58.56% of the costs in Account 376 as customer related and 41.44% as demand related. (Direct Testimony of Cost of Service and Rate Design Panel, p. 29 and Exhibit ___ (COSRD-3) Schedule 2 Page 1 of 8.) Account 376 comprises more than 50% of the Company's plant in service (See Exhibit ___ (COSRD-3) Schedule 1 Page 1 of 9), so the handling of this account has an outsized impact on the overall allocation of the Company's rate base, as well as depreciation, income taxes and other costs that are indirectly affected by the treatment of this

account. Not surprisingly, this disputed aspect of the Company's ECOS study had a very significant impact on the bottom line results – the class rates of return.

Even though the facilities in question are not located on the premises of individual customers, and are not directly attributable to specific customers, the Company chose to classify these costs as predominantly customer-related, which had the effect of shifting much of the burden of these costs onto residential and small commercial customers, to the direct benefit of larger customers. As we explain in detail below, we strongly object to the Company's treatment of these costs in its ECOS study, and urge the Commission to follow a more reasonable approach to handling these costs.

B. Fully Allocated Embedded Costs

Q. Please elaborate on the purpose of fully allocated ECOS studies, and explain some of their limitations.

A. Fully allocated ECOS studies divide total test-year revenues, rate base, and operating expenses among the various customer classes to estimate the ROR earned from each class. These types of studies have long been used by this Commission and other regulators as a tool to assist with developing electric and gas rates. As long as their limitations are recognized, and reasonable allocation formulas are employed, fully allocated ECOS studies can be useful in determining an appropriate distribution of the revenue requirement amongst the various customer classes.

Although people sometimes speak of ECOS studies as reflecting "cost-causation," this is only true to a limited degree. Because delivery rates are based upon embedded costs, these studies do not always report direct cause-and-effect relationships between the consumption decisions of the class members and the costs incurred by the utility. Thus a "cost" identified in the study is not necessarily the actual expense that a particular group of customers causes or imposes on the system, or a measure of the amount by which total costs would be reduced if that customer or group of customers were to leave the system.

C. Disputed Category of Costs

Q. Can you be more specific about the "disputed costs," which you believe are not being appropriately handled in the Company's ECOS study?

A. Yes. As noted above, we disagree with the proposed treatment of Plant Account 376: Distribution Gas Mains, which the Company proposes to classify as 58.56% customer-related and just 41.44% as demand-related. (Direct Testimony of Cost of Service and Rate Design Panel, p. 29.) This proposal is inconsistent with the Company's own data concerning the cost of mains, and it does not follow sound principles of cost-causation.

Q. Has the Company explained why it proposes to allocate such a large fraction of the cost of its distribution mains essentially in proportion to the number of customers in each class?

A. Not in detail. The Company began by classifying certain costs as "demand or capacity" related and other costs as "commodity or energy related." It apparently concluded that a portion of the cost of distribution mains did not vary in proportion to "demand or capacity," and since this portion also didn't neatly fall into the "energy related" or "revenue related" category, the Company assigned it to the "customer related" category, notwithstanding the tenuous relationship between distribution mains and number of customers.

The closest the Company comes to explaining or defining these costs is as follows:

> Costs associated with providing service to a customer are defined as customer-related costs. Costs associated with the customer's total annual use of gas, or the customer's total peak demand for gas, are not included in customer-related costs.
>
> (Direct Testimony of Cost of Service and Rate Design Panel at pp. 10-11.)

This does not explain why a cost would be customer-related but not demand-related. From one perspective, nearly all costs of the distribution system are "associated with providing service" to customers – as delivering gas to customers is the fundamental purpose of the entire system. But, from that same broad perspective, it is equally true that all costs of the system are also "associated with" demand. This "explanation" thus provides no meaningful standard – if the Company's sole criterion is whether a cost is incurred for the purpose of serving customers, it could justify classifying any (or all) costs as customer-related, including the cost of gas commodity itself.

Q. Can you explain why you disagree with classifying a portion of the cost of distribution gas mains as "customer-related" and why you believe Account 376 should not be allocated or recovered on a per-customer basis?

A. Yes. This classification does not accurately reflect cost-causation, it results in a significant – and inappropriate – shifting of the cost burden from larger to smaller customers, and it would weaken customers' incentives to conserve energy. We further disagree with the assumption implicit in this classification that the majority of distribution main costs are "fixed" and therefore should be allocated and recovered on a relatively uniform per-customer basis, while a much smaller proportion of costs are "variable" (and should therefore be allocated and recovered on the basis of energy deliveries or demand).

Q. Are you claiming there are no fixed costs of the distribution system?

A. No. We will readily concede that most of the costs in Account 376 are fixed, in the classic sense that these costs do not vary in the short run. Even in the long run, the cost of a distribution main does not vary in exact proportion to its gas handling capacity, because of economies of scale. But that does not provide a logical reason for classifying a portion of the investment as "customer related" or insisting that this portion must be recovered almost entirely from small customers. No matter how elaborate and detailed the calculations, any analysis of the cost of a hypothetical "minimum system" falls flat as a logical justification for putting more of the cost burden on small customers, because there is no

causal connection between the identified costs and the number of customers served by the system.

The key point to realize is that the costs identified by a "minimum system" or "zero intercept" study do not vary as a function of the number of customers – either in the short run or in the long run. In the long run, the minimum (or "zero intercept") cost of the distribution system varies as a function of the number of miles of streets served by the system (and the difficulties encountered along the way) while the remaining cost (in excess of the minimum) primarily varies with the anticipated peak load that each main is expected to accommodate over its useful life (which can be 40 or more years).

Since the "minimum system" or "zero intercept" costs do not vary in proportion to the number of gas customers along any given route, or on the system as a whole, there is no compelling economic reason to classify these costs as "customer related" or to recover them on a uniform per-customer basis.

Additionally, recovering "minimum system" or "zero intercept" costs on a per-customer basis is contrary to how those costs would be recovered in a competitive market. In competitive markets, those customers who value the product the most, or purchase the largest quantity, typically pay a larger share of joint costs than customers who buy less, or value the product less. Our recommended approach, discussed *infra*, is more consistent with this pattern, because it recognizes there are vast differences in benefits received by gas customers of different sizes. In addition to being more consistent with the typical pricing practice in competitive markets, such an outcome is also consistent with other important policy goals, like the encouragement of economic efficiency and energy conservation. We see no reason to deviate from this normal outcome by

forcing small customers to pay an inordinately large share of the joint cost burden on the basis of a “minimum system” or “zero intercept” analysis.

Q. It might be argued that the Company's “zero intercept” approach better conforms to the principle of cost causation. What is your response?

A. We strongly disagree. To begin with, we would note a “zero intercept” analysis is a purely hypothetical construct – no rational utility would install a pipe with zero gas-carrying capacity. This significantly limits the relevance and usefulness of the zero intercept method even before considering any of our other concerns.

On a purely hypothetical basis, one can visualize certain costs, like the cost of opening a trench (or boring through the ground) and positioning the equipment needed to lay the pipe, which might not vary much with the diameter of the pipe. However, these hypothetical costs do not relate to, or vary with, the number of customers on the system. They instead vary primarily according to the number of miles of streets and roads where the trench will need to be opened (or boring will need to occur), the difficulties involved in carrying out this process, and the number of times the pipe-handling equipment will need to be repositioned. Yet road mileage is not a useful statistic for apportioning costs to different customers or groups of customers because some sections of road may have no customers, while other sections may have dozens or hundreds of potential customers, despite being of the same length.

Furthermore, in understanding what “causes” trenching or boring costs to be incurred, the number of customers is <u>not</u> one of the most important variables – instead, the difficulties encountered along the route will be far more important in determining the costs that are incurred. The key point is that even in a purely

hypothetical "zero intercept" analysis, the investment in question will not vary in proportion to the number of customers.

At the root of this dispute is a difference in philosophy concerning what causes costs to be incurred, and what factors are most important in designing regulated rates. On page 23 of its Smart Rate Design for a Smart Future paper (issued July 2015), the Regulatory Assistance Project explained:

> Most people who have ever tried their hands at designing rates for regulated utilities invariably say that it is "more art than science." Because of the shared nature of the system and the need to spread cost recovery fairly among all customers, the idea that rates should be set based on customer cost causation is a foundational concept in rate design. Analysts who ask, in a causal sense, "why" costs are incurred often reach different conclusions than those who measure, in an engineering sense, "how" costs are incurred.

We agree with these comments, and would further assert that the principle of "cost causation" (as well as the principle of fairness) supports recovering the "zero intercept" or "minimum system" costs based largely, if not entirely, on the basis of demand. In general, the aggregate demand for energy (and the associated income potential) is the primary factor that influences most decisions to install distribution mains along a given route in the first place, and individual energy usage (and the associated cost savings potential) is what motivates decisions by individual households or businesses to connect to the mains if they are installed.

In contrast, the number of customers does not provide a good proxy for the factors that explain "why" these costs are incurred (what "causes" these costs to be incurred), since this completely ignores the volume of energy each

customer is expected to use, and thus the extent to which there is an economic basis for installing the distribution main in the first place ("why" the gas main was constructed). Similarly, the number of customers connected to the main completely ignores what size main will be needed ("how" the main will be engineered, and thus how much it will cost). In other words, the number of customers does not explain what causes these costs to be incurred in either sense – "why" the costs are incurred or "how" the costs are incurred. In contrast, economic demand explains "why" these costs are incurred, and peak demand explains "how" these costs are incurred.

Stated another way, if the system planners believe significant economic demand exists for natural gas along a given road, and that demand is strong enough to justify the investment, the system will be built or expanded along that road – regardless of the number of customers that will be served by the expansion. The key question is not simply whether buildings exist (or how many buildings), but the demand for energy by the owners or tenants in those buildings – whether the demand for gas is strong enough to justify construction of the system along that particular road ("why it will be built"). In turn, the anticipated peak rate of usage by those potential customers will determine the design of the system – what size pipes are used, the need for pressure regulators and other aspects of the design – and thus it is also fair to say that customer demand is closely associated with "how" it is built – to ensure the main has sufficient capacity to accommodate everyone's energy needs even during peak times.

Q. The National Association of Regulative Utility Commissions Gas Distribution Rate Design Manual, published in June 1989 ("NARUC Manual") mentions an

alternative to the "minimum system" or "zero intercept" approaches, based upon the argument that "mains and services are installed to serve demands of the consumers and should be allocated to that function." Can you provide an example of a case where the Commission accepted 100% demand classification of distribution mains?

A. Yes. In the most recent Orange and Rockland gas rate case (14-G-0494), DPS Staff proposed classifying Account 376 as 100% demand-related. On page 23 of its Gas Rates Panel's direct pre-filed testimony, Staff stated:

> We recommend allocating the costs of distribution mains system on a 100% demand and 0% customer basis. Due to this change, the distribution-customer amount in the calculation of monthly customer costs will be zero, as these costs are now allocated to distribution-demand, reducing the monthly customer costs.

On October 16, 2015, the Commission ultimately adopted DPS Staff's proposal in the Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan.

Q. Are there other cases in which the utility or DPS Staff advocated a similar approach?

A. Yes. In KEDNY and KEDLI cases 06-M-0875, 06-G-1185, and 06-G-1186, DPS Staff advocated to allocate distribution mains costs as 100% demand. Aric J. Rider explained on page 15 of his Direct Testimony:

> For the purposes of revenue allocation and rate design, I propose that all mains be allocated as demand in the classification step. The primary purpose of this change is to

> more closely identify the minimum costs for each service class when the study is re-rerun . . . .

Similarly, New York State Electric and Gas ("NYSEG") and Rochester Gas and Electric ("RG&E") classified 100% of Distribution Gas Mains in Plant Account 376 as demand-related in several different gas proceedings, including cases 09-G-0716, 09-G-0718, and 01-G-1668. In the 2009 cases, NYSEG and RG&E supported their position by explaining some of the flaws in the minimum system or zero intercept method. For example, page 8 of NYSEG and RG&E's Embedded Cost of Service Panel's Rebuttal Testimony reads:

> The identification of any minimum installed system contains a corresponding load carrying capability. It is, in fact, this load carrying capability that must be recognized and removed from customer load prior to allocating the remaining (non-minimum) costs to customer classes…..Unfortunately, both Staff and Dr. Rosenburg chose to ignore this important aspect of proper development of appropriate allocation factors. *The results simply over-allocate costs to the smaller residential and general customer classes*, which are the majority of customers. In the final analysis, the proposed recognition of a customer component by both Staff and Dr. Rosenberg should be dismissed as flawed and unrepresentative of cost responsibility.

This Panel further stated:

> Q. Your previously mentioned a "double dip" cost allocation concern. What is your specific concern?
>
> A. In the use of a minimum size methodology, the associate costs are assigned to all classes based on the number of customers. This minimum size can have a sizable capacity level which must be considered and removed from customer load responsibility before finalizing allocation factors. Failing to do this extra step results in this load

> responsibility being ignored and the remaining non-minimum system costs being allocated on each class's total load, thereby creating a serious flaw – a "*double dip*" – *which results in an over-allocation of these costs to smaller customer classes*.
>
> (*Id*. at pp. 8-9)

In their subsequent rate cases (cases 15-G-0284 and 15-G-0286), NYSEG and RG&E again proposed a 100% demand classification Account 376. (See Direct Testimony of David A. Heintz at p. 27.)

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Q. Has the minimum system or zero intercept alternative approach been universally accepted in other jurisdictions?

A. No. These approaches have been under debate for more than 30 years, and the results of this debate have varied widely.

Q. Can you provide examples where either the minimum system or zero intercept approach has been rejected in other states?

A. Yes. One example is from Massachusetts, where the concept was advocated by an intervenor but rejected by the Massachusetts Department of Public Utilities:

> The Consortium contests the Company's classification of distribution mains as entirely capacity-related (id., p. 10). The Consortium presented Alan Rosenberg, a consultant with Drazen-Brubaker Associates, Inc., to support its capacity classification and allocation arguments . . . .
>
> The Consortium proposed that the Company conduct a study to identify and classify a minimum portion of

> distribution mains as customer-related . . . The Department has reviewed and rejected a similar argument in Colonial Gas Company, D.P.U. 84-94, pages 73 and 77-78 (1984) ("Colonial").
>
> In Colonial, the Department . . . found that the size of a distribution main is determined by the amount of gas that would be sent through a particular main during the peak time period. Id., p. 77. The Department found that distribution mains are capacity related . . . Moreover, the Department has previously found that the costs of distribution mains do not vary with the loss or the addition of a single customer. Western Massachusetts Electric Company, D.P.U. 20110-A, p. 13 (1982).
>
> The Department notes that a strong correlation between two variables does not necessarily indicate cost causation. Specifically, the fact that number of customers and length of mains are strongly correlated does not establish that number of customers is a significant factor relative to other factors in causing the Company to incur distribution mains costs. In this instance, the Department will not rely on a statistical measure without a demonstration that the hypothesis being examined is based on sound reasoning.
>
> The Department reaffirms its past findings and concludes that there is a cost causative relationship between loads and distribution mains. The Department finds that there is no need for the Company to conduct a study to identify and classify a portion of distribution mains as customer-related.
>
> (Order Dated October 31, 1991, DPU Case 91-60 (WL 531844))

Another example is this case in Illinois:

> The arguments of [Illinois Industrial Energy Consumers] IIEC and Wal-Mart do not persuade the Commission to deviate from its past decisions and now embrace the [Minimum Distribution System] MDS. The MDS method fails to properly emphasize the purpose of the distribution system — that being to satisfy a customer's daily demand for electricity. Ameren's method, on the other hand, does not suffer from

> this weakness. The Commission also continues to believe that distinguishing the cost of connecting customers to the distribution system and the cost of serving its demand remains problematic. Moreover, the Commission is hesitant to rely on the 1992 NARUC manual cited by IIEC and Wal-Mart because of its age and the changes in the electric industry. Accordingly, the Commission will not adopt the MDS in this proceeding. The Commission also declines to adopt IIEC's suggestion that Ameren be required to present a COSS in its next rate case incorporating the MDS approach. In the Commission's view, it would be unreasonable to require Ameren to perform a COSS that incorporates a method repeatedly rejected by the Commission.
>
> (Order dated November 21, 2006 (Ill. C.C.) (WL 3863623))

The Michigan Public Service Commission rejected the Minimum System concept in a 1989 case involving Consumers Power Company, choosing instead to use an allocation factor based upon average and peak ("A&P") demand:

> Consumers and ABATE each proposed that a portion of Consumers' distribution mains — the minimum system — is customer related and should be allocated on a customer basis . . . The Staff proposed that all distribution mains be allocated pursuant to the A&P methodology.
>
> The ALJ determined that the Staff's allocation of distribution mains was reasonable and recommended its adoption by the Commission. In so doing, he noted the Commission's preference for the A&P allocation methodology and its recent rejection of the minimum system concept in Case Nos. U-8635, U-8812, and U-8854.
>
> The Commission finds the arguments raised by ABATE and Consumers are not persuasive. Any allocation methodology utilized by the Commission is, to some extent, arbitrary. Ideally, no customer should be assessed more than the exact cost of serving that customer. However, attaining this

> ideal standard would require a separate rate computation for each customer.
>
> In the final judgment, the question is not whether a more exact methodology can be constructed; rather the question is whether the method and result are reasonable. The Commission finds the method proposed by the Staff, which has been repeatedly utilized by the Commission in other cases, is an accepted and reasonable way to distribute the cost of Consumers' distribution mains. Accordingly, the exceptions filed by ABATE and Consumers are rejected.
>
> (Order dated December 7, 1989 in Case Nos. U-8678 et al. (WL 418755))

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Another example involved Mountaineer Gas Company, where the West Virginia Public Service Commission weighed extensive arguments back and forth before ultimately rejecting the Minimum System approach:

> Staff takes issue with the Company's use of the minimum system approach for allocating distribution plant . . . Staff recommends using class peaks as a better method of allocation of the distribution mains.
>
> Mountaineer maintains that the minimum system methodology presented in its class cost of service study is the better method because: 1) it is consistent with good allocation principles; 2) it is recognized by NARUC and approved by several state Commissions . . .
>
> Mountaineer disagrees with Staff and CAD's allegations that: 1) the minimum system is not based on cost causation; 2) that the minimum system places to much emphasis on number of customers; and, 3) that Mountaineer should allocate more of its cost based on through-put. . .
>
> Similar to the return on equity and rate of return issue, the Commission is faced with the testimony and exhibits of well qualified experts on rate design and three separate class cost of service studies. In the final analysis, the adoption of

> any of the parties' recommendations is a matter of judgment. The Commission is persuaded by the CAD's arguments regarding the Seaboard formula of allocating distribution system cost. The Commission is further persuaded by Staff and CAD's arguments that Mountaineer's class cost of service study places undue emphasis on allocating costs on the basis of the number of customers, which tends to unfairly allocate more costs to the residential customer.
>
> (Order dated October 29, 1993 in Case No. 93-0005-G-42T (WL 494175))

In a 2002 case involving Gulf Power Company, the Florida Public Service Commission rejected both versions, explaining their reasoning as follows:

> The concept of a zero load cost is purely fictitious and has no grounding in the way the utility designs its systems or incurs costs because no utility builds to serve zero load. There is no real equipment that equates to the costs identified by the ZI methodology. We have rejected MDS in the past for this very reason.
>
> (Order No. PSC-02-0787-FOF-EI dated June 10, 2002 in Docket No. 010949-EI (WL 1349501))

That decision referred to the Florida Public Service Commission's history of rejecting the method, citing an example from more than 20 years earlier, where it had explained its fundamental discomfort with the concept:

> The Company and staff have proposed the use of a theoretical minimum distribution cost . . . we do not agree that a theoretical cost of a minimum distribution system is appropriate . . . The installation of the distribution system is made in anticipation of a projected level of actual use. The system does not contain a basic theoretical minimum

> distribution system. Reliance on such a mechanism is speculative at best.
>
> (Order 9599, issued October 17, 1980 in Docket No. 800011-EU.)

A similar decision was made in a 1984 case involving Puget Sound Power & Light, where the Washington Utilities and Transportation Commission rejected both options:

> The Commission rejects the company's use of the zero-intercept method. The minimum system method, of which the zero intercept method is a variant, is also rejected. Both methods are likely to lead to the double allocation of costs to residential customers and over allocation of costs to low use customers.
>
> (Order dated January 19, 1984 in Case No. U-83-26 (WL 1022551))

Q. To wrap up this portion of your discussion, can you briefly explain the conclusion you reached from your review of cases in New York and other states?

A. Our review indicates that the Company's proposed ECOS methodology, in addition to being factually unsupported, is inconsistent with a substantial amount of precedent. While the minimum system approach is sometimes used by other New York utilities, it is far from universally accepted, and sporadic past approvals do not justify accepting the results of the zero intercept analysis in this case. The concept is fundamentally unsound, and we recommend that cost results based upon this methodology not be given any significant weight in this case.

Q. Up to this point, you have been discussing your objections to the Company's treatment of distribution mains on conceptual grounds. If one were to accept the Company's methodology *arguendo*, would that Company's 58.56% "customer-related" classification factor be appropriate?

A. No. The Company's own data contradict this number. It was developed using a flawed regression analysis that arbitrarily excluded portions of the available data, resulting in a calculated cost for a "zero diameter" pipe that is actually <u>higher</u> than the installed cost of 1-inch pipes. Even if the Commission chooses not to reject the zero intercept or minimum system approach on conceptual grounds, it should still reject the 58.56% factor as clearly excessive.

Q. Can you please briefly elaborate on these concerns?

A. Yes. The underlying premise of the "zero intercept" approach is that the "customer related" portion of Account 376 should be based upon the minimum cost of installing the smallest possible pipe (with a hypothetical diameter of zero inches). The statistical analysis developed by the Company purports to show this minimum possible cost is $8.27 per linear foot. Yet, the Company's own data show that the Company has installed thousands of feet of 1-inch diameter pipes at an average installed cost of $2.56 per linear foot. These data directly contradict the Company's assertion that the minimum possible cost of installing a main is $8.27 per foot, and also demonstrate the inherent unreliability of a zero-intercept analysis. We note that if the Company had implemented the Minimum

System approach using this $2.56 per foot cost of 1-inch pipes, it would have developed a customer related percentage of just 18.12%, instead of 58.46%.

Equally disturbing, the Company's regression analysis was based upon observations for only 11 pipe sizes, despite the fact that the Company has cost data for more than 30 pipe sizes. A review of the Company's workpapers suggest it experimented with excluding various portions of the available data before deciding to use the particular "run" that yielded the 58.56% zero intercept factor. The Company's witnesses do not explain their decision to select this particular run, or to exclude other available data. It is not necessarily unreasonable to exclude the data for a handful of "outliers" or pipe sizes with unusually weak or clearly unreliable data (e.g., data that show a negative cost or zero footage), but the Company has offered no explanation for excluding half of the available pipe size data, most of which appear to be valid.

It is also important to realize that when linear regression is applied to this data set, the intercept fluctuates widely, as various portions of the data are included or excluded. In general, it appears that as more and more pipe sizes are removed from the analysis, the calculated intercept tends to increase, but the results of that calculation are not particularly reliable. For instance, if the Company had used data for all pipe sizes with 1,000 or more installed feet, it would have developed an intercept of closer to $1.00 per foot, rather than $8.27. It is possible that the Company has not analyzed this particular option. However, it does appear to have analyzed – and chosen to ignore – a "Run 2," whose results are included in their workpapers. Run 2 was based upon 16 observations

and has a higher Adjusted R Squared value than the run selected by the Company (indicating a stronger correlation). Run 2 yielded an intercept of $2.65 per foot - translating into a Customer/Demand split of 18.75%/81.25%.

Q. Do you have any further comments concerning the statistical approach used by the Company?

A. Yes. From a statistical perspective, the analytical approach used by the Company is deeply flawed, because the tool it used – a simple linear regression – is not well suited to the task at hand, particularly in the context of this data set. Linear regression is a popular statistical technique that is often used to model the relationship between a scalar dependent variable (typically referred to as "Y") and one or more explanatory variables (also referred to as independent variables) which are typically denoted as "X" (or X1, X2, X3, etc.). When the technique is used with just one explanatory variable, it is called simple linear regression.

One problem is that a linear regression is normally used to estimate the slope of the equation for the X variables, not the intercept. In fact, linear regressions often yield unstable or unreliable estimates for the intercept, so it is a common practice to work around this weakness by specifying an assumed intercept when running a regression. This is done for the purpose of improving the accuracy of the slope of the explanatory variables, which is the primary focus of a typical regression analysis.

The second problem is that the cost of building a distribution main varies widely, depending on multiple variables including the nature of the terrain, the type of soil or rock below the surface of the ground, and the extent to which manmade obstacles (e.g. water mains) will be encountered. While the diameter of the pipe is an important explanatory variable (e.g. smaller mains are lighter, and may be easier to route around obstacles), the diameter is not the only potentially relevant variable. Hence, any attempt to statistically analyze embedded cost data will yield results of questionable value unless a more sophisticated tool, such as multiple regression, is used – and the analysis considers data for more of the explanatory variables that actually determine the cost of installing a distribution main.

A third problem (closely related to the first problem described above) is that the $8.27 statistical estimate of the intercept in this case is simply not anywhere near as precise as it may initially appear to the uninitiated. Even if the Company's statistical analysis were to be accepted at face value (putting aside for the moment our concerns about the Company's arbitrary exclusion of large portions of available data, and its failure to consider other relevant explanatory variables), the analysis does not demonstrate that a zero diameter pipe would cost approximately $8.27 to install. To the contrary, the 95% "confidence interval" around this point estimate actually stretches all the way from $0.57 on the low end to $15.97 on the high end. In other words, the most that can be concluded from this analysis is that there is a 95% chance the cost of a zero diameter pipe would fall somewhere between $0.57 and $15.97. This extremely

large confidence interval further highlights the unreliability of the Company's analytical method.

D. Recommended Treatment of Disputed Costs

Q. Given the problems with the Company's "zero intercept" approach, what alternative do you recommend?

A. We recommend classifying 100% of Plant Account 376 as demand-related. We recommend using this approach because it is has been used by other utilities (in New York State and across the United States) and because it offers a reasonable basis for analyzing costs. We also recommend in future proceedings that the Company provide the results of an ECOS study that classifies the distribution mains in Plant Account 376 as 100% demand-related.

Q. Has the Company estimated the impact of your suggested ECOS changes?

A. Yes. The Company re-ran its ECOS model based on classifying Plant Account 376 as 100% demand in response to an Information Request (UIU-3 No. 58). Schedule 1 of Exhibit__(URP-1) shows the results of this run, as well as the Company's study. As shown on Page 1 of Schedule 1 of Exhibit__(URP-1), in the Company's ECOS study the residential SC-1 class has a below-average return of 5.71%. However, this result is entirely dependent upon the Company's decision to classify 58.56% of Account 376 as "customer related." If this Account is classified as entirely demand related, the residential SC-1 class has a higher than average return. Other classes are also distorted by the zero intercept

analysis, with the returns for all other classes moving closer to the system average if Account 376 is classified as demand-related. For instance, the SC-3 class has a return of 9.82% when Account 376 is classified as 100% demand related, which in our view is a more realistic estimate of the profitability of this class than the 16.34% return shown in the Company's ECOS study (*see* Exhibit___(URP-1) Schedule 1). The high volume industrial SC-13 TC subclasses also are shown to have returns closer to the system average if the distortions introduced by the zero intercept analysis are removed. The one exception is the Cogeneration class, which shows a low return under both studies.

Q. Is this proposal consistent with the NARUC Manual?

A. Yes. The NARUC Manual recognizes the widespread technique of classifying the distribution system as 100% demand related. The NARUC Manual also discusses the approach of classifying a portion of mains as customer-related, and points out that this approach can be controversial, as indeed it is in this case. The Manual notes the "contrary argument" against the inclusion of distribution costs as customer costs (and in favor of classifying the system as entirely demand related): "mains and services are installed to serve demands of the consumers and should be allocated to that function." (NARUC Manual at p. 23.)

V. RATE DESIGN

Q. As a preliminary matter, before discussing the Company's rate design, can you briefly describe their residential customers, including the percentage that are heating customers?

A. Approximately 93% of the Company's accounts are residential customers, and nearly 99% of these customers use gas to heat their homes. We also note that approximately 16% of the Company's Residential customers are low income customers, served under SC-2 and its various subclasses.

Q. What is the typical usage for residential customers?

A. Residential customers have varying usage, with an overall weighted average of 18.342 Mcf in January 2015 and 2.133 Mcf in July 2015, as shown in Exhibit___(VFP-3) Schedule 1 Page 3 of 7. The graphs in Schedule 3 of Exhibit__(URP-1) show the range of variation in monthly usage during January 2016 and during July 2015. These graphs also suggest the SC-2 Low Income customers follow a similar usage pattern as SC-1 customers.

Q. Please explain NFG's proposals concerning its customer charge and delivery volumetric rates for SC-1 residential heating and non-heating customers.

A. The same rates apply to both residential heating and non-heating customers. The Company proposes to increase the SC-1 residential customer charges (minimum bill) for up to the first 0.4 Mcf of usage by approximately 27%. The

remaining revenue increase will be collected through the volumetric block rates, to which the Company proposes some minor adjustments. Specifically, the Company proposes to increase the rate for the first block by 4% and the tail block (for usage of 5 Mcf and above) by 16%, as shown below:

SC-1 – Residential Delivery Rates	Current Delivery Rates	Proposed Delivery Rates	Percent Increase	Percent of Volume	Share of Proposed Revenues	Share of Revenue Increase
First 0.4 Mcf	$15.54	$19.66	**27%**	5%	52%	76%
Next 4.6 Mcf	$3.72554	$3.88449	**4%**	38%	33%	10%
Over 5 Mcf	$1.00813	$1.16708	**16%**	58%	15%	15%

Low income customers in SC-2 pay similar rates as SC-1 customers, but also receive discounts. Low-income discount levels are subject to change based on the outcome of Case 14-M-0565, *Proceeding to Examine Programs to Address Energy Affordability for Low Income Utility Customers*. UIU discusses low-income issues in more detail in the Direct Testimony of Gregg C. Collar.

Q. Would you please explain the Company's rate design proposal for SC-3 general service (i.e., commercial) customers?

A. SC-3 currently has a 3-tier declining block rate structure, which the Company proposes to maintain, with a tail block rate that starts after 1,000 Mcf. The Company proposes to increase the delivery customer charge by approximately 33%, which would recover approximately half of the proposed revenue increase.

The remaining portion of the revenue increase would be collected through the delivery volumetric block rates, as shown below:

SC-3 – Non-Residential General	Current Delivery Rates	Proposed Delivery Rates	Percent Increase	Percent of Volume	Share of Proposed Revenues	Share of Revenue Increase
First 1 Mcf	$17.86	$23.77	**33%**	4%	22%	50%
Next 49 Mcf	$2.51345	$2.67950	**7%**	48%	43%	24%
Next 950 Mcf	$1.94282	$2.10887	**9%**	48%	34%	25%
Over 1,000 Mcf	$1.56935	$1.73540	**11%**	2%	1%	1%

Q. How do NFG's customer charges compare to those in other jurisdictions?

A. The Company's current residential rate falls toward the high end of the range of what other utilities around the country have been charging, while the current general service rate is closer to the middle of the range. In May 2015, the American Gas Association ("AGA") published a report entitled Natural Gas Utility Rate Structure: The Customer Charge Component – 2015 update ("AGA Report") that concluded that the nationwide median residential customer charge was just $11.25 per month, and the median rate for commercial customers was $22 per month. As shown in table 2 of the AGA Report (below), New York gas utilities have some of the highest customer charges in the United States.

AGA Report Table 2 – Average Gas Utility Customer Charges by Region

Census Region	Residential	Commercial
New England	$13.50	$28.41
Middle Atlantic	$14.60	$23.60
East North Central	$11.38	$24.00
West North Central	$13.16	$24.40
South Atlantic	$10.00	$22.00
East South Central	$14.00	$16.96
West South Central	$13.24	$18.51
Mountain	$10.80	$20.00
Pacific	$4.95	$14.90

More detailed data are also available in Appendix 1 to the AGA Report. These data show that as of 2015, customer charges spanned a wide range both across jurisdictions and within jurisdictions. The report includes many examples from around the country of gas utilities with much lower customer charges than the Company, including AGL – Florida City Gas in Florida ($8.00 customer charge), Alliant – Interstate P&L in Minnesota ($5.00), Avista Corp. in Idaho ($8.00), Avista Corp. in Oregon ($4.25), Centerpoint Arkla in Arkansas ($9.75), Chesapeake Utility Corp. in Maryland ($8.75), Coserv Gas in Texas ($7.00), Dominion – Hope Natural Gas in West Virginia ($8.99), Integrys – Wisconsin Public Service Corp. in Michigan ($5.00), Liberty Utilities in Iowa ($7.95), Liberty Utilities in Illinois ($9.90), Middle Tennessee Natural Gas Utility District ($7.00), Montana-Dakota Utilities in North Dakota ($3.50), Montana-Dakota Utilities in South Dakota ($8.40), Northwestern Energy in Montana ($7.30), Northwestern Energy in Nebraska ($8.00), Piedmont Natural Gas in North Carolina ($10.00), Public Service Electric and Gas in New Jersey ($5.46), Questar Gas in Utah ($6.75), Sempra – Southern California Gas in California ($4.90), UGI Penn Gas

in Pennsylvania ($2.19), Washington Gas Light in the District of Columbia ($9.90), Wisconsin Power & Light ($1.51), and many others.

Q. Gas utilities sometime argue that a fixed monthly fee is the correct way to recover costs that are fixed. How do you respond to this argument?

A. Utilities sometimes advocate increasing fixed monthly charges, or matching fixed rates to fixed costs, because it provides them a more predictable revenue stream. However, higher fixed charges shift cost burdens from larger customers to smaller customers (who do not realize a commensurate level of benefit from being connected to the system), and do not provide appropriate long-term conservation incentives for customers. Higher fixed charges thus are not an appropriate policy goal in New York State, and do not advance the public interest.

Although rate design is more of an art than a science, it is nevertheless a very important and controversial part of the overall regulatory process. It is often in this stage of the proceeding where the Commission's decisions will have the greatest short-run impact on customers, and the greatest long-run impact on the Commission's overall policy goals. We do not believe recovering “fixed costs” through “fixed rates” is a meaningful or appropriate policy goal. Nor do we view rate design as an area where deference can appropriately be given to the utility's preferences, or where “business as usual” is an appropriate philosophy.

The following discussion (in the context of electric rates) from page 5 of the Smart Rate Design for a Smart Future issued by the Regulatory Assistance Project in July 2015 is informative:

> Rate design is important because the structure of prices — that is, the form and periodicity of prices for the various services offered by a regulated company — has a profound impact on the choices made by customers, utilities, and other . . . market participants. The structure of rate designs and the prices set by these designs can either encourage or discourage usage at certain times of the day, for example, which in turn affects resource development and utilization choices. It can also affect the amount of electricity customers consume and their attention to conservation. These choices then have indirect consequences in terms of total costs and benefits to society, environmental and health impacts, and the overall economy.

In our view, some aspects of the Company's current rate structure do not provide the right price signals to encourage energy efficiency and do not sufficiently incentivize customers to invest in energy efficiency. We believe reasonable steps can be taken to improve this situation, strengthening the incentive for energy conservation and more effectively advancing the Commission's policy goals.

To advance the policy goals set forth in the 2015 New York State Energy Plan (system efficiency, carbon reductions, customer empowerment, and energy affordability) as well as the goals underlying the ongoing REV proceeding (Case 14-M-0101), we recommend that the Commission steer the Company away from low tail block rates and high customer charges. Together with customer engagement technologies, customers can take greater control over their utility

bills, and more clearly and effectively reward them for investing in more insulation and energy-efficient appliances and heating systems, as well as making lifestyle adjustments that enable them to use energy more efficiently (such as using automated thermostats to adjust temperatures for maximum efficiency while maintaining comfort).

Q. How do the Company's customer charges compare to its customer costs?

A. The Company's current SC1 customer charge is $15.54 per month, which it proposes to increase to $19.66 per month. The analogous charges for SC-3 general service customers are $17.86 and $23.77, respectively. As shown on Schedule 2 of Exhibit__(URP-1), all of these charges are significantly higher than the Company's customer costs. Our cost estimates are similar to the ones developed by the Company with two important exceptions: we have excluded distribution mains and services.

We excluded distribution mains for the same reasons explained earlier in the context of the class ECOS results. We excluded services for similar reasons: service lines are sized to accommodate the maximum anticipated demand on the line, and a single service can be shared by multiple customers of varying sizes. For example, the same service may deliver gas to retail stores and offices of widely varying sizes located in the same building. Similarly, the same service may be used by apartments of widely varying sizes, placing different demands on the service. Considering that the installed cost of a service can vary depending on anticipated demands, and considering that customers of varied sizes can share the same service, we do not think it appropriate to include services in the

customer cost analysis, or require these costs to be recovered through a fixed monthly charge.

Q. What do you recommend with respect to gas customer charges and volumetric delivery block rates for residential and commercial customers in this proceeding?

A. We believe the customer charge for residential and commercial customers (SC-3 general service) should not be increased in this proceeding. This is consistent with some recent proposals of other New York State gas utilities (see page 39 of Consolidated Edison's Direct Testimony of Gas Rate Panel in Cases 16-E-0060 *et. al.* and page 28 of Keyspan Gas East Corporation d/b/a National Grid Direct Testimony of Rate Design Panel in Cases 16-G-0058 *et. al.*). Depending on the revenue requirement ultimately approved by the Commission in this case, it may be appropriate and feasible to modestly decrease the customer charge. If so, the remaining revenue increase would be collected in the volumetric delivery rates. For residential customers and SC-3 general service consumers, it would also be appropriate to take some modest steps toward a block structure that declines less steeply by applying a larger percentage increase to the tail block rates than is applied to the other blocks.

Improved price signals can be achieved by recovering more of the Company's revenues through the tail block. If this change is introduced gradually, it would prevent rate shock and yet still move towards rates that provide stronger incentives for customers to conserve energy. This will be more consistent with other policies which are intended to encourage greater energy

efficiency (e.g., outreach and customer education to encourage better weatherization; rebates for the installation of high efficiency heating systems), and it will treat small commercial customers more equitably relative to larger commercial customers served under the SC-3 rate schedule.

To mitigate the degree to which this flattening could increase bill volatility for heating customers, while still achieving the goal of improving price signals, we recommend introducing a seasonal rate structure, which retains a somewhat more steeply declining block rate structure during the months of January through March, while flattening rates to a greater degree during other months. This will reduce the degree to which bill volatility would increase during three of the coldest months, while still ensuring that customers are provided with stronger price signals and an increased incentive to conserve energy.

Q. Does this conclude your direct testimony, which was prefiled with the Commission on August 26, 2016?

A. Yes.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service	Case 16-G-0257

REBUTTAL TESTIMONY

OF

UIU RATE PANEL

Dated: September 16, 2016
Albany, New York

UTILITY INTERVENTION UNIT
DIVISION OF CONSUMER PROTECTION
NYS DEPARTMENT OF STATE
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I. INTRODUCTION AND OVERVIEW

Q. Would the Utility Intervention Unit ("UIU") Rate Panel please state their names and business address?

A. **(Johnson)** My name is Ben Johnson, and my business address is 5600 Pimlico Drive, Tallahassee, FL 32309.

(Panko) My name is Danielle M. Panko and my business address is 99 Washington Avenue, Suite 640, Albany, NY 12231.

Q. Are you the same panel members that filed direct testimony on August 26, 2016?

A. Yes, we are.

Q. What is the scope of this testimony?

A. We are providing UIU's response to the direct testimonies of Jeffry Pollock on behalf of Multiple Intervenors ("MI") and of the Department of Public Service's Staff Gas Rates Panel. In the event that we do not respond to specific issues raised by, or statements made by these witnesses (or others), that should not be construed as agreement with those statements.

Q. Have you prepared any exhibits to be filed with your rebuttal testimony?

A. Yes, Exhibit ___ (URP–2) accompanies our testimony.

Q. Would you please describe your Exhibit?

A. Exhibit ___ (URP-2) contains five schedules. Schedule 1 compares the results of the proposed Embedded Cost of Service ("ECOS") studies presented by National Fuel Gas ("the Company"), MI, and Utility Intervention Unit ("UIU"). Schedule 2 shows the effects of using MI's and the Company's revenue allocation proposals, as well as the effects of using MI's general revenue allocation approach in conjunction with UIU's proposed ECOS study (as shown in Exhibit ___ (URP-1)) and Staff's proposed revenue requirement. Schedule 3 displays the current and proposed customer charges and volumetric delivery rates for SC-1 residential and SC-3 commercial in comparison with the rates proposed by the Company and Staff, as well as rates we developed to illustrate the effect of our rate design recommendations. Schedules 4 and 5 provide similar comparisons in the context of typical monthly bills. These schedules show the monthly delivery and total bill impacts for residential and small commercial customers, respectively – thereby providing further insight into the impact of the positions taken by the Company, the Staff Gas Rates Panel, and UIU.

II. EMBEDDED COST OF SERVICE

Q. A significant portion of your direct testimony concerned the Company's ECOS study. Did other witnesses also discuss the Company's ECOS study?

A. Yes. Both Mr. Pollock (on behalf of MI) and the Staff Gas Rates Panel discussed the Company's ECOS study.

A. Would you please briefly explain Mr. Pollock's position concerning the Company's ECOS study?

Q. Mr. Pollock generally agrees with the Company's ECOS study, with one minor exception – he contends the Company made a mistake in classifying FERC Accounts 378 (Measurement and Regulation Station Equipment), 385 (Measurement and Regulation Industrial Station Equipment), and the corresponding expense accounts. In response to MI's Information Request MI-I-1, which the Company provided prior to Mr. Pollock's filing of his direct testimony, the Company acknowledged that Account 385 "should have been classified as customer related since these are installations in place at large customers' premises, in order to provide service to specific customers." However, the Company explained that "the allocations to classes does [sic] not change since it was completed via a special study" and that allocation of the corresponding O&M costs also "does not change." Similarly, in its IR response, the Company acknowledged that Account 378 should have been classified as demand-related, since this account includes the costs of equipment used in measuring gas other than the measurement of gas deliveries to customers. However, the Company argued that "Account 378 was also properly allocated to customer classes, since it used the peak demand allocator."

In his testimony, Mr. Pollock does not mention the Company's explanation that Account 385 was allocated using a special study, so the misclassification has no direct impact, nor does he elaborate on the

Company's explanation that Account 378 was “properly allocated to customer classes, since it used the peak demand allocator.” He does, however, acknowledge on page 5 that his proposed correction does “not change how these specific accounts are allocated to service classes” so any potential impact is limited to indirect effects through “internal allocation factors that are used to allocate general and intangible plant, labor expenses and other 'downstream' plant and expenses.”

Q. Did Mr. Pollock provide an alternative to the Company’s ECOS study, reflecting his proposed changes to these internal allocators?

A. Yes. The rate of return results are nearly identical for all classes, as shown in Schedule 1 of Exhibit ___ (URP-2). A comparison of the results in the first two columns shows that MI's modification to the internal allocators has no practical significance, because all of the classes with a below-average return in the Company's study has a similar below-average return in MI's version, and all of the classes with an above-average return in the Company's study have similar above-average returns in MI's version. The lack of any significant difference between the Company's originally filed study and MI”s “corrected” version is clear from a comparison of the class unitized rates of return, as shown in the same schedule.

Q. What conclusions can be drawn from these rate of return comparisons?

A. First, the Company and MI class rate of returns are very similar. The only nominal differences are in the internal allocators in both ECOS studies. As such, we refer to the Company and MI ECOS studies together as the "Company/MI study." Second, the Company/MI study and the UIU study both show an above-average return for the SC-3 General Service class, and a below average (negative, in fact) return for the Cogen class. Third, the returns for the other classes are, in a sense, mirror images. For instance, the Company/MI study shows a moderately below-average return for the SC-1 Residential class, while the UIU study shows a slightly above-average return for this same class. Similarly, each of the Transportation Charge ("TC") subclasses within the SC-13 class show well above-average returns in the Company/MI study, and each of these subclasses show well below-average returns in the UIU study.

Q. What conclusions did Mr. Pollock draw from the Company/MI study?

A. Primarily, Mr. Pollock claims the SC-1 Residential class is "producing returns that only are 60% of the system average" and "all of the SC-13 subclasses are producing returns well in excess of the system average."

Q. Do you agree?

A. No. These conclusions are dependent upon the Company's inappropriate treatment of distribution mains which, as we discussed in our direct testimony, is invalid. If distribution mains were instead allocated based 100% on

demand – as we recommended in our direct testimony and Staff has recommended in other New York gas rate cases – the disparity in class rates of returns from the system average is generally reduced, with the SC-1 Residential class showing a rate of return that is similar to the system average. As well, all of the SC-13 TC subclasses show rate of returns well below the system average, rather than above the average.

Q. What comments did the Staff Gas Rate Panel testimony offer regarding the Company's ECOS study?

A. Staff did not discuss the Company's ECOS study in detail, instead stating: "Generally speaking, we believe the [E]COS study to be reasonable." However, Staff then went on to express concerns regarding the Company's ECOS, including as follows:

> Q. Do you agree with use of a zero intercept study to determine the allocator to classify distribution mains?
>
> A. Not necessarily. We believe that the results may under-allocate costs to classes that have large demands placed on the system and few customers.

Direct Testimony of Staff Gas Rates Panel at p. 74.

The Panel also suggested at page 75 of its testimony that the Company's ECOS was not to be relied upon for the purposes of revenue allocation. We discuss the role of the ECOS in revenue allocation in Part III of this testimony.

Q. Did Staff further articulate why the zero intercept approach may under-allocate costs to customers with large demands?

A. No; however, as we explained in our direct testimony, the zero intercept approach suffers from many shortcomings – both in concept and in the context of the Company's ECOS study. The overall impact of the combined flaws of the Company's approach would be to allocate an excessive share of the cost of distribution mains on a uniform per-customer basis, thereby under-allocating costs to customers with large demands.

Q. Can you please explain why you believe this approach tends to under-allocate costs to customers with large demands?

A. Yes. To understand the problem, consider a hypothetical example of a small business owner who operates a 1,000 square foot retail store. In this example, the small retailer competes with several other retailers, including a 50,000 square foot department store down the street. In this example, the department store uses about 50 times more natural gas to heat its store (compared to the small retailer), but its peak demand is only 40 times as large. This translates into a moderate cost advantage for the department store, when comparisons are made on an apples-to-apples, per-square foot

basis – a pattern that applies to most of the items included in their respective utility bills. This would also hold true for the cost of distribution gas mains if they are allocated using the demand-based ECOS methodology – the department store would be allocated a share of the distribution gas mains in proportion to its larger peak demand, which works out to a net 20% cost savings on a per-square foot basis.

In contrast, under the Company's approach, the department store would be allocated the same "zero-intercept" portion of distribution main costs as its much smaller competitor, despite using 50 times more energy and having a peak demand that is 40 times larger. This would clearly be inequitable, as one store receives 50 times as much natural gas from the system. The inequitable nature of this cost allocation methodology becomes even clearer when their respective shares of these fixed infrastructure costs are compared on an apples-to-apples basis: the department store would pay 98% less per square foot than its smaller competitor. Considering that the fixed overhead costs of the distribution main system cannot be directly attributed to, and are not caused by, either store, this extreme disparity in cost burden is clearly inequitable.

To consider a similar analogy, it is hard to imagine anyone arguing that the smaller store (or its landlord) should pay the same dollar amount of property taxes as the department store. The fact that the smaller retailer would be required to pay 50 times more per square foot than its larger competitor would surely dissuade the taxing authorities. In reality, of course,

the tax burden is spread much more equitably, because virtually all local, state and federal taxes are calculated as a function of property value, sales volume, income, or some other appropriate factor that varies with the size of the taxpayer – thereby ensuring that the tax burden is equitably spread across small and large firms.

Q. Does the same concern apply to residential gas customers?

A. Yes. If the Company's approach were fully implemented, the Company would collect at least the same amount for its "minimum system" costs from a hypothetical 400 square foot studio apartment as it would collect from a 3,500 square foot house – even if the latter residence uses more than five times as much gas.

Indeed, the Company's zero intercept approach may lead the Company to collect <u>more</u> in "minimum system" costs from a two-family building than from a twenty-unit building down the street. This inequitable result would occur if the landlord of the larger building obtains gas for all of its tenants through a single meter, so each tenant counts as only 1/20th of a "customer," while the owner of the smaller building installs separate meters for each unit, so that each apartment in the smaller building is billed as a separate individual customer.

It is thus easy to see why the Staff Gas Rate Panel might have concerns about the potential for under-allocating costs to customers that

place large demands on the system (like the hypothetical department store and master-metered apartment building) under the Zero Intercept approach.

Q. Has Staff expressed similar concerns in any other recent cases?

A. Yes. In the Central Hudson rate cases 08-E-0887 and 08-G-0888, Staff proposed the same approach we are recommending in this case for Central Hudson's gas ECOS study. On pages 14-15 of its direct testimony in that case, the Staff Gas Rates Panel rejected Central Hudson's zero intercept analysis, stating:

> For the purpose of revenue allocation and rate design, we propose that all mains be allocated as demand in the classification step. The purpose of this change is to more closely identify the minimum customer costs for each service class. In the Panel's view, the result of the revised study will more closely indicate costs associated with a basic level of service, which is more representative of the costs saved when a customer leaves the system.

Similarly, in the recent Orange and Rockland rate case (15-G-0494), Staff proposed to allocate gas distribution mains as 100% demand, rather than utility's proposed customer/demand split. Staff's approach was ultimately adopted by the Commission Order in that case. Staff also supported a similar allocation in the recent NYSEG and RG&E rate cases (15-G-0283 and 15-G-0286), where the Staff Gas Sales and Revenue Panel accepted NYSEG and RG&E's proposal to allocate 100% of gas distribution mains to demand.

III. REVENUE ALLOCATION

Q. How did the Company use its ECOS study in developing its revenue allocation proposals?

A. The Company largely disregarded the results of its ECOS study for the purposes of revenue allocation.

Q. How did Staff respond to this approach?

A. The Staff Gas Rates Panel accepted the Company's revenue allocation proposal <u>because</u> that proposal did not rely on the Company's ECOS study. At page 75 of its direct testimony, the panel stated:

> The Company did not propose to shift revenues to correct for return imbalances as shown in the [Company's E]COS study. We, therefore, believe the [revenue allocation] methodology is reasonable.

This is similar to Staff's approach in the recent Keyspan Gas East Corporation d/b/a National Grid ("KEDLI") and Brooklyn Union Gas Company d/b/a National Grid ("KEDNY") (or combined "the Companies") gas rate cases (16-G-0058 and 16-G-0059), where Staff gave no weight to the Company's ECOS study and instead advocated a uniform percentage rate increase for firm gas customers.

Q. How did MI respond to this approach?

A. Mr. Pollock advocated stricter adherence to the Company's ECOS study for the purposes of revenue allocation, in conjunction with a +-15% tolerance band around the system average rate of return. He urged the Commission to impose higher rate increases to classes with rates of return below the 15% tolerance band and much lower increases to classes with rates of return above the 15% tolerance band.

Specifically, Mr. Pollock proposed to increase rates for the SC-1 Residential and the Cogen class by at least 1.25 times the system average percentage increase, and to increase rates for other classes by only 0.25 times the system average percentage. The bill impacts of this approach depend somewhat on the magnitude of the revenue requirement, but the general effect would be to increase rates for residential (and Cogen) customers by at least five times more than for other classes. On page 14 of his direct testimony, Mr. Pollock further proposed an even larger discrepancy between the rate increase applied to SC-1 and that applied to other classes if the Commission reduces the Company's requested revenue requirement by 50% or more. As Page 2, Schedule 2 of Exhibit ___ (URP–2) shows, if the Company's proposed revenue requirement and Mr. Pollock's revenue allocation proposal were both accepted by the Commission without modification, SC-1 rates would increase by 19.23%, while rates for most other classes would increase by just 3.63%.

Q. What is your response to Mr. Pollock's revenue allocation approach?

A. We strongly disagree with his proposal because it is based on a flawed ECOS study and it is too extreme. Even if one were to accept the results of the Company's flawed ECOS study, Mr. Pollock's proposal to increase rates for SC-1 customers by five times more than for other customers would be excessive.

Q. What would be the impacts of Mr. Pollock's general revenue allocation approach if it were applied in a less extreme manner in conjunction with a more reasonable ECOS study?

A. In Exhibit ___ (URP–2), Schedule 2, Page 1, we compare the effect of using Mr. Pollock's revenue allocation proposal to that of the Company. Then, in Exhibit ___ (URP–2), Schedule 2, Page 2, we illustrate the effect of using a more moderate version of Mr. Pollock's general approach in conjunction with the results of the ECOS study we presented in our direct testimony and the Staff's adjusted revenue requirement of approximately $1.9 million. Since this ECOS study shows that SC-1 and SC-13 TC 1.1 have class rates of return that are close to the system average, these classes would be given a rate increase that is approximately equal to the system average percentage increase. Since the rate of return for SC-3 is above average, this class would receive an increase of 0.75 times the average percentage rate increase (rather than 0.25 times, as Mr. Pollock proposed). The remaining classes would receive above-average percentage increases in order to bring them

closer to the system average rate of return. Importantly, under this much less extreme approach, no service class would receive a rate increase that differs widely from that of any other service class, consistent with the principle of gradualism.

IV. RATE DESIGN

Q. Can you please briefly respond to the testimony of Staff with respect to the rate design applicable to residential and small commercial customers?

A. The Staff Gas Rates Panel accepted many of the Company's rate proposals with minimal explanation or commentary, modified to fit Staff's revenue requirement. We disagree with the Staff's proposed rate design for essentially the same reasons we disagree with the Company's proposed gas rate design – we do not think those proposals go far enough toward improving price signals.

Q. Have you developed exhibits that can help clarify your rate design recommendations as compared to the rates proposed by the Company and Staff?

A. Yes. Schedule 3 of Exhibit ___ (UGRP-2) illustrates our rate design recommendations, under the assumption that Staff's revenue requirements and billing determinants will be adopted by the Commission. Our

recommended rates can therefore be compared directly to the rates proposed by the Staff Gas Rates Panel.

Our rate design recommendations are illustrated in the far right column of each page of Schedule 3. Our illustrative delivery rates can be compared to the Company's existing and proposed delivery rates (shown in the first and second columns) and the delivery rates developed by the Staff witnesses (shown in the fourth column).

Q. If customer charges are reduced, as you recommend, will they still be in excess of your estimate of the corresponding customer costs?

A. Yes. For convenience, the following table directly compares our cost estimates, as shown on Schedule 5 of Exhibit ___ (UGRP-1) accompanying our direct testimony, to our recommended customer charges, as well as the current charges, as set forth on Schedule 3 of Exhibit ___ (UGRP-2).

Customer Class	Current Rate	Estimated Cost	UIU Recommended Rate
SC-1 Residential	$15.54	$7.49	$14.75
SC-3 General Service	$17.86	$16.93	$17.00

As this table demonstrates, our recommendations take a reasonable step toward setting customer charges closer to the level of actual customer costs, while also recognizing the principle of rate continuity.

Q. Have you developed exhibits that illustrate the impact of your recommended rate design on monthly customer bills?

A. Yes. Schedules 4 and 5 of Exhibit ___ (UGRP-2) illustrate the impact of our rate design recommendations on monthly bills (delivery and total) for SC-1 residential and SC-3 commercial customers. On pages 1 through 2 we present bill impacts that are primarily focused on the portion of the delivery charges that we discussed in our direct testimony. These comparisons include the majority of the delivery portion of the bill and the billing and payment charge, and exclude portions of the bill that recover commodity costs, gross receipt taxes, and other miscellaneous items that are not the primary focus of our testimony. This approach provides a clear representation of the true impact of the different rate designs presented by the Company, Staff, and UIU with respect to these rate elements. Pages 3 through 4 of Schedules 4 and 5 compare current and proposed total monthly bill impacts excluding sales tax based on the rates presented by the Company, Staff, and UIU.

Q. Does this conclude your rebuttal testimony, which was prefiled with the Commission on September 16, 2016?

A. Yes.

A.L.J. LECAKES: And that is all of the witnesses from UIU. Is that correct?

MR. ZIMMERMAN: Yes, Your Honor. We do have two exhibits --

A.L.J. LECAKES: Oh yeah, I'm sorry.

MR. ZIMMERMAN: -- on the bid that UIU Rate Panel's testimony. It's URP1 filed with the direct testimony and URP2 of the rebuttal testimony.

A.L.J. LECAKES: Okay. So URP1 filed with the direct testimony will be marked for identification as Exhibit 166 and URP2 will be marked for identification as Exhibit 167. PULP?

MS. JORGENSEN: Yes, thank you, Your Honor. I have one affidavit of William D. Yates -- I mean D. Yates. He is the Director of Research for the Public Utility Law Project. He prepared a 36 page type-written series of questions and answers along with a cover page labeled as Corrected Testimony of William D. Yates, CPA for the Public Utility Law Project of New York, Inc. He also prepared a five-page type-written series of questions and answers along with a cover page labeled as Supplemental Testimony of William D. Yates, CPA for Public Utility Law Project of New York, Inc. Finally, he prepared a five-page type-written series of questions and

answers along with a cover page labeled as Rebuttal Testimony of William D. Yates, CPA for the Public Utility Law Project of New York, Inc. May I request that they be incorporated into the record as if they were spoken orally today?

A.L.J. LECAKES: Granted. They will appear on the CD labeled PULP Testimony and in the folder PULP Testimony for Hearing. It will be -- the first one should be the Corrected Direct Testimony of William D. Yates for PULP, the second one should be the Supplemental Testimony of William D. Yates, and then the third file should be the Rebuttal Testimony of William D. Yates. May I have the affidavit please?

MS. JORGENSEN: Thank you for the brief pause, Your Honor.

A.L.J. LECAKES: That's okay.

MS. JORGENSEN: Yes, William D. Yates has exhibits --.

A.L.J. LECAKES: Wait, do I have your affidavit please?

MS. JORGENSEN: Oh the affidavit? Oh, I'm so sorry.

A.L.J. LECAKES: Thank you. We will mark the affidavit as Exhibit 168.

STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation (New York), for Gas Service.

CASE 16-G-0257

CORRECTED TESTIMONY OF WILLIAM D. YATES, CPA

FOR

PUBLIC UTILITY LAW PROJECT OF NEW YORK, INC.

Dated: September 2, 2016

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I. INTRODUCTION AND OVERVIEW

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND IDENTIFY FOR WHOM YOU ARE PRESENTING TESTIMONY IN THIS PROCEEDING.

My name is William D. Yates, my office address is at Public Utility Law Project of New York, Inc., 90 South Swan Street - Suite 401, Albany, NY 12210. I am presenting testimony in this proceeding for the Public Utility Law Project of New York, Inc. (PULP).

Q. PLEASE DESCRIBE PULP AND YOUR RELATIONSHIP TO THE ORGANIZATION.

PULP is a New York not-for-profit corporation that was formed in 1981. Its primary focus is to promote and defend the legal rights of residential utility consumers by educating the public, regulators and elected officials about the impacts of utility rates; conducting research on the rights and energy burden of utility consumers; and, advocating with an emphasis on the rights and needs of low-income utility consumers. I have been employed by PULP in various capacities since July 1990. I am currently Director of Research for PULP.

Q. WHAT ARE YOUR EDUCATIONAL BACKGROUND, YOUR PROFESSIONAL QUALIFICATIONS, AND EMPLOYMENT HISTORY?

I am a graduate of Colgate University (B.A. in History, 1982) and a graduate of the New York University Stern School of Business Administration (M.S. in Accounting, 1982). I am a Certified Public Accountant (CPA), licensed to practice in New York State since 1987, and I am a member of the American Institute of Certified Public Accountants (AICPA).

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW YORK STATE PUBLIC SERVICE COMMISSION?

A. Yes, I have provided testimony on behalf of PULP in prior rate proceedings including Cases 12-E-0201, 12-G-0202, 13-E-0030, 13-G-0031, 16-G-0058 and 16-G-0059, and 16-E-0060 and 16-G-0061. In 12-E-0021 and 12-E-0202, I testified regarding the experience of utility customers of Niagara Mohawk who enter into contracts for "commodity" (or "supply") with energy service companies ("ESCOs"). In 13-E-0030 and 13-G-0031, I testified regarding the Joint Proposal's low-income assistance changes, and data reflected in Collection Activity Reports filed monthly by Con Edison concerning its residential customers with arrears who are at risk of actual or threatened interruption of utility service. In Cases 16-G-0058 and 16-G-0059, I testified regarding affordability issues in the KEDNY and KEDLI service areas of National Grid in the rate cases filed on January 29,

2016. In Cases 16-E-0060 and 16-G-0061, I testified regarding affordability issues in the Con Edison service area in the rate cases filed on January 29, 2016.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony presents evidence regarding the difficulties a large number of the Company's low-income customers are having paying their utility bills. I provide analyses of data pertinent to this issue, discuss the relevant Company programs and its recommendations in this case, and discuss and provide recommendations regarding alternate rate designs that would reverse regressive impacts upon low-income and low-usage (i.e., "green") households, and would incentivize excessive energy users to conserve.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring six exhibits. Exhibit ___ (WDY-01) consists of 6 pages of data from the Company's Low Income Program Annual Reports. Exhibit ___ (WDY-03) consists of 8 pages of Company IR responses to Staff.[1] Exhibit ___ (WDY-04) consists of 14 pages of data from the U.S. Census Bureau's American Community Survey. Exhibit ___ (WDY-05) presents the Company's response to information request UIU-3 and comprises 2 pages. Exhibit ___ (WDY-06) consists of 63 pages of data from the OTDA website. Exhibit ___

[1] Exhibit_(WDY-02) intentionally omitted.

(WDY-07) consists of 4 pages of analysis based on data in the Company's Bill Frequency Report (Filing Letter, Attachment B, Page 1).

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE SOURCES YOU REVIEWED THAT LED YOU TO MAKE YOUR FINDINGS AND FORM YOUR RECOMMENDATIONS.

A. As discussed in more detail in the remainder of my testimony, I reviewed information from several sources that provided evidence that a significant, rising majority of the Company's low income customers (households with less than $35,000 of income annually) cannot afford their utility bills. Using these sources, I analyzed indicia of current unaffordability in the Company's service area, and factors that would tend to increase such unaffordability over time, such as:

- Persistently oppressive Housing-Cost Burdens among low income households,
- The absence of any proposal to increase low income discounts during the pendency of the Company's Petition for Rehearing / Reconsideration / Clarification in Case 14-M-0565, *Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers* (the Low Income Order Petition),
- The inclusion of master metered two-to-four family dwellings (Master Metered Residential Customers) and an increasing number of high usage, non-residential

customers (SC1 Non-Residential Customers) in the residential class of service, the presence of whom impedes the ability of the class to be representative of a homogenous group of residential customers for which rates can be properly designed that are just and reasonable, and

- Rate designs that feature high fixed basic costs of service (Basic Service Charges) and declining block rates for gas delivery service.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE AFFORDABILITY PROBLEMS FACED BY THE COMPANY'S LOW INCOME CUSTOMERS?

A. Based on the findings I discuss throughout my testimony; I recommend three actions that should be taken to reduce the affordability problems of many of the Company's customers. In the context of this rate case, the Company should agree, or the Commission should require the Company to:

1) Adopt the eight-month discount for HEAP recipient customers as originally proposed in Company's Customer Service Panel testimony, should the Company's Low Income Order Petition not be answered by the effective date of the order in this proceeding,

2) Create one or more new service classes for the accounts of master metered two-to-four family dwellings (Master Metered Residential Customers) and those non-residential customers currently included in Service Class 1 (SC1 Non-Residential Customers).

Consider whether it is appropriate to mix these two types of customers in the same class. If not, create separate classes for each, and

3) Establish a multi-party working group to study and prepare a report upon the advisability of having the Company adopt alternative residential class rate designs (Green Rate Designs), the purpose of which would be to achieve greater affordability for all average and lower usage customers, including low income customers, through the implementation of rate designs that incentivize energy conservation and efficiency in support of New York State's declared goal of reducing greenhouse gas (GHG) emissions 40% by 2030 and 80% by 2050. Integral to any new rate design strategy would be a plan to draw upon the Company's demonstrated expertise in energy conservation and efficiency assistance, and proactive engagement with customers experiencing payment problems, including the needs of those of its low income customers whose usage is above average. For example, the Company has pioneered an innovative program to increase the percent of its customers in arrears that negotiate and execute deferred payment agreements (DPAs) on their past-due balances through the use of electronically signed DPAs (e-DPAs), and the Company has effectively used its Low Income Usage Reduction Program (LIURP) to assist its low income customers whose usage is above average. While these efforts are helping to mitigate the unaffordability crises to an extent, programmatic activities do not and cannot replace what comprehensive rate design could achieve in terms of preventing cost shifts and keeping price impacts to a minimum.

II. UNAFFORDABILITY AND THE COMPANY'S LOW INCOME CUSTOMERS

Q. ARE THE COMPANY'S LOW INCOME CUSTOMERS HAVING DIFFICULTY PAYING THEIR BILLS?

A. Yes. There are numerous indicators of long term and increasing unaffordability among the Company's customers whose households receive less than $35,000, which are discernible from the

- United States Census Bureau's American Community Survey (ACS) data on the persistent burden of housing costs, including utilities, upon households in the Company's service area whose annual income is less than $35,000, and
- Discovery responses obtained by PULP, New York State Department of Public Service (Staff), and the Utility Intervention Unit of the New York State Department of State (UIU), and the
- Low Income Customer Affordability Assistance Program (LICAAP) and HEAP Residential Assistance Service (HRAS) Program reports (collectively, Low Income Program Reports) filed by the Company with the Commission.

In the remainder of my testimony, I will utilize the above evidence to support my finding that utilities are unaffordable for the Company's low income customers, a situation that must be addressed in this rate case proceeding.

A. ECONOMIC FACTORS

1. Persistently Oppressive Housing-Cost Burdens among Low Income Households

Q. WHAT ECONOMIC FACTORS DID YOU DISCOVER THAT ARE CAUSING THE COMPANY'S LOW INCOME CUSTOMERS TO HAVE DIFFICULTY PAYING THEIR UTILITY BILLS?

A. In the counties served by the Company, the most significant economic factor causing low income customers to have trouble paying their bills is that a large and persistent majority of households with income less than $35,000 are spending at least thirty percent (30%) of their income on housing costs, which include utility costs. Further, a significant minority (36%) are spending at least 50% of their incomes on housing costs. The U.S. Census Bureau refers to "at least 30% of income on housing costs" as the "Housing Cost Burden"; 30 percent being the maximum amount that a household can devote to housing costs before the household is considered to be "burdened." Most average-size households in the Company's service area (approximately 2.6 persons) with incomes less than $35,000 that experience such a Housing Burden qualify for income-based assistance programs such as HEAP or Food Stamps, based on the eligibility guidelines of those programs. They are also very likely to comprise the majority of customers enrolled in one or more of the Company's low income assistance programs (Exhibit ___WDY-04, Pages 1-14).

In response to Information Request (I/R) UIU-3 (Exhibit ___WDY-05), requesting the Company to provide the number of low income residential heating and non-heating customers in the Company's service territory who are currently enrolled in the low income discount program, the Company provided the following table:

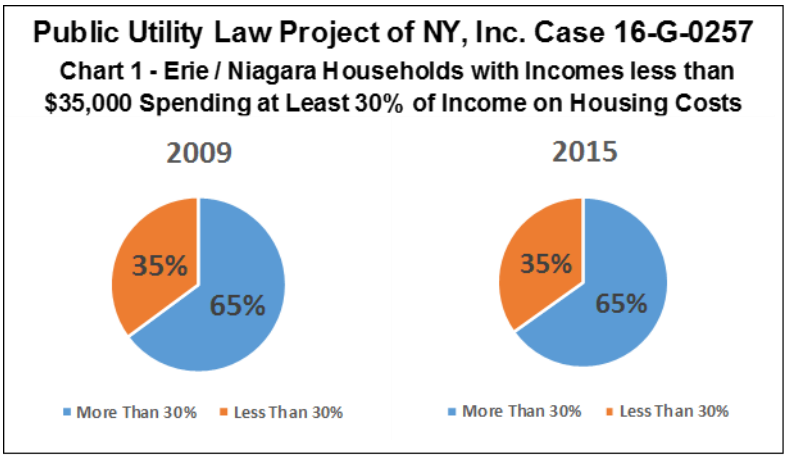
National Fuel Gas Distribution Corporation
New York Division
Low Income Discount Customers by County

County	Total	Heating	Non-Heating
ALLEGANY	2,016	2,009	7
CATTARAUGUS	2,415	2,411	4
CHAUTAUQUA	8,095	8,064	31
ERIE	63,811	63,704	107
GENESEE	1,403	1,400	3
LIVINGSTON	65	65	0
MONROE	55	55	0
NIAGARA	8,362	8,348	14
ONTARIO	212	211	1
STEUBEN	1,373	1,370	3
WYOMING	574	571	3
TOTAL	**88,381**	**88,208**	**173**

Source: Company Response to I/R UIU-3

As explained in Chart 1 below, the Housing Cost Burden on low income households in the Company's service area persisted between 2009 and 2014. Additionally, in the two counties comprising 80% of the enrolled customers in the Company's low income discount program (Erie and Niagara), 65% of low income households experienced a Housing Cost

Burden in 2009. By 2014, the Housing Cost Burden of low income households in these counties remained at 65% (Exhibit ___WDY-04, Pages 1-14).



Source, United States Census Bureau, American Community Survey - 2009, 2014

A more detailed look at this situation is presented in Table 1 below, which breaks down the persistence of the low income Housing Cost Burden from 2009 – 2014 by county, and among renters and homeowners:

Public Utility Law Project of New York, Inc. - Case 16-G-0257 (National Fuel Gas)

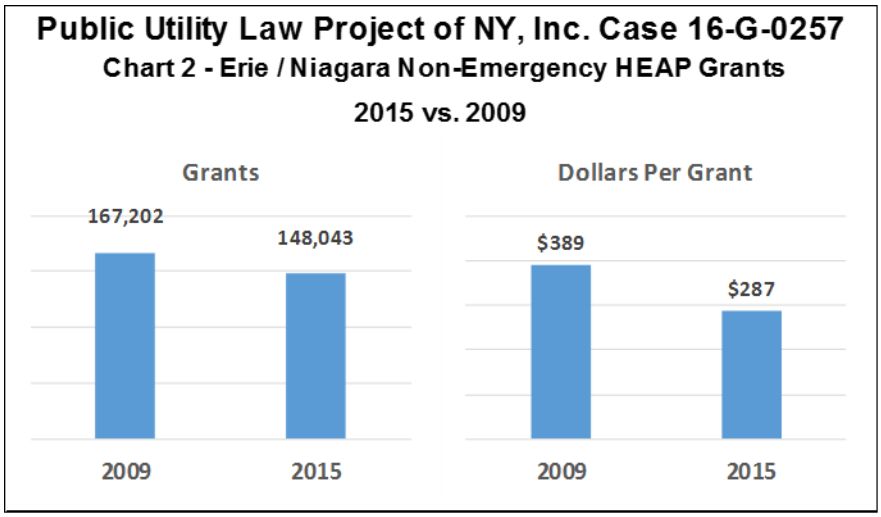
Table 1 - Percent of Erie / Niagara County Households with Incomes Less Than $35,000 Spending at Least 30% of Income on Housing Costs Including Utitlties, 2009 - 2014

Description	Year	Erie County			Niagara County			Total		
		Renters	Owners	Total	Renters	Owners	Total	Renters	Owners	Total
Number of Households with Income Less Than $35,000	2009	82,357	64,309	146,666	17,252	16,890	34,142	99,609	81,199	180,808
	2014	79,638	56,868	136,506	16,976	15,594	32,570	96,614	72,462	169,076
Spend 30% or More on Housing Costs Including Utilities	2009	70.5%	59.2%	65.5%	64.5%	59.5%	62.0%	69.4%	59.2%	64.9%
	2014	72.1%	57.0%	65.8%	67.9%	56.2%	65.0%	71.3%	56.9%	65.1%
Spend 50% or More on Housing Costs Including Utilities	2014	42.9%	29.3%	37.2%	37.7%	27.6%	32.9%	42.0%	28.9%	36.4%

Source, United States Census Bureau, American Community Survey - 2009, 2014

Table 1 also reflects a new measure of low income Housing Cost Burden that the Census Bureau began reporting in 2014: households experiencing a Housing Cost Burden of at least 50%; that is, spending at least 50% of income on housing costs including utilities. In 2014, 36% of low income households in Erie and Niagara counties reported a Housing Cost Burden of at least 50% of income (Exhibit ___WDY-04, Pages 1-14).

A contributing factor to the persistent Housing Cost Burden of the Company's low income customers from 2009 to 2014, specifically tied to utilities, was the sharp reduction in the number and average dollar amount of HEAP grants – funds that low income customers use to pay their heating bills. Chart 2 shows just how steep the cutbacks in HEAP have been for the Company's low income customers in Erie and Niagara Counties (Exhibit ___WDY-06, Pages 26, 58):



Source, New York State Office Office of Temporary & Disability Assistance, Case Load Statistics, September 2009, 2015.

With Housing Cost Burdens persisting and the level of HEAP funding available to low income households in Erie and Niagara counties sharply reduced, it is not surprising that more of the Company's low income customers are struggling to pay their utility bills. This becomes apparent upon a review of the Company's Low Income Program Reports. From 2011 through 2015, the percent of customers participating in the LICAAP program whose accounts were in arrears rose from 39% to 49% (Exhibit ___WDY-01, Pages 2, 4). The result is that almost half of LICAAP customers can't keep up with their utility bills, despite the assistance provided by the program.

B. UTILITY-SPECIFIC FACTORS AND RECOMMENDATIONS

Q. WHAT ARE SOME OF THE UTILITY-SPECIFIC FACTORS CONTRIBUTING TO THE DIFFICULTY THE COMPANY'S LOW INCOME CUSTOMERS ARE HAVING PAYING THEIR BILLS?

A. In this testimony I focus on four factors specific to the Company that currently contribute, or will be contributing to the unaffordability crisis in the Company's service territory:

1. The absence of any proposal by the Company to increase low income discounts during the pendency of the Company's Low Income Order Petition,

2. The inclusion of master metered two-to-four family dwellings (Master Metered Residential Customers) into the SC1 class of service,
3. The increasing number of high usage, non-residential customers (SC1 Non-Residential Customers) in the residential class of service, and
4. Rate designs that feature high fixed basic costs of service (Basis Service Charges) and declining block rates for gas delivery service.

1. No Increase in Low-Income Discounts Proposed

Q. PLEASE DESCRIBE THE ABSENCE OF ANY PROPOSAL TO INCREASE LOW INCOME DISCOUNTS DURING THE PENDENCY OF THE COMPANY'S THE LOW INCOME ORDER PETITION.

A. In its supplemental testimony, the Low Income Order Panel indicated that, during the pendency of its Low Income Order Petition, the Company would not follow through with the Company's original proposal set forth in the Customer Service Panel's testimony to extend the annual period of the HRAS low income discount to eight months from five months. (Low Income Order Panel Testimony at 8) The effect of failing to execute the Company's proposal of extending the HRAS discount on typical low income customers with average usage would be to more than double the proposed increase in their monthly total bill, from the 3.2% calculated in the Comparison of Monthly Bills for the HRAS class,

to 7.0%. (Company Response to DPS-33, JRB-1 Revenue Exhibits.xlsx, "Tabulation" tab; Exhibit_WDY-03, Page 1, Residential-SC1, Page 2, HRAS-SC2).

This change, which may not be recognized by all of the parties in this proceeding because the Comparison of Monthly Bills schedules have not been updated since the filing of the Company's supplemental Low Income Panel testimony, would harm low income customers - the very segment the Low Income Order was intended to assist, and who are already having the most difficulty paying their utility bills.

Q. WHAT ACTION DO YOU RECOMMEND SHOULD BE TAKEN TO ADDRESS THIS SITUATION?

A. In the unlikely event that the Commission does not answer the Company's Low Income Order Petition, the Company's original proposal to adopt an eight-month discount period for HRAS customers should be adopted. In the alternative, rates for customers in the HRAS, LICAAP and any other low income programs should be frozen until the low income order is clarified.

2. Inclusion of master metered two-to-four family dwellings into the SC1 class of service

Q. TO WHOM DOES THE SERVICE CLASS NO.1 (SC1, RESIDENTIAL) APPLY.

A. The Company's tariff for Service Class No. 1 (SC1, Residential) states that this class of service is applicable for:

> *"Any use of gas where consumption is less than 25,000,000 cubic feet per year for residential purposes in a one-family, two-family, three-family, or four-family dwelling, whether such service is individually or master metered, and in separately metered apartments in all other multiple-family dwellings. Where gas used for non-residential and residential purposes is not separately metered, this Service Classification shall apply if more than 50% of the cubical content of the pertinent structure is used for residential purposes.*
>
> *Also for all gas utilized exclusively in connection with any post or hall owned or leased by a not-for-profit corporation that is a veterans' organization; for religious purposes by any corporation or association organized and conducted in good faith for religious purposes; and for community residences as defined in subdivision twenty-eight, twenty-eight-a or twenty-eight-b of Section 1.03 of the Mental Hygiene Law, provided, however, that such community residence shall be operated by a not-for profit corporation and if supervisory staff is on*

site on a twenty-four hour per day basis, that the residence provides living accommodations for fourteen or fewer residents."

(Tariff at Leaf 149)

Q. WHAT ARE THE EFFECTS OF THE INCLUSION OF MASTER METERED TWO-TO-FOUR FAMILY DWELLINGS (MASTER METERED RESIDENTIAL CUSTOMERS) AND AN INCREASING NUMBER OF HIGH USAGE, NON-RESIDENTIAL CUSTOMERS (SC1 NON-RESIDENTIAL CUSTOMERS) IN THE RESIDENTIAL CLASS OF SERVICE.

A. SC1, the residential class of service, has traditionally included both individually metered dwellings - such as single family homes, and individually metered apartments and multi-family dwellings. The class has also included customers that are served by master meters in two-to-four family dwellings. Historically, in terms of the *purpose* of the gas service being delivered – to provide heating and non-heating gas for one's home - it has been perfectly logical to include master metered two-to-four family dwellings in SC1. However, *designing rates* for both directly metered and master metered customers within the same class is problematic: the two types of meters measure gas usage that is not comparable. A customer who is the landlord of a multi-family dwelling served by one (master) meter will pay the same $15.54 monthly basic service charge as a homeowner in a directly metered single-family dwelling (Company Tariff at Leaf 149). Further, since the

number of households in a multi-family dwelling is, by definition, greater than one, the average usage reflected by a master meter is likely to be much higher than the average usage reflected by an individual meter. Table 2 below shows the difference between the monthly delivery charges for an individually metered single family residence and a master metered multi-family dwelling with four households – all of whom consume the same volume of gas monthly:

Public Utility Law Project of New York, Inc. - Case #16-G-0257 (National Fuel Gas)

Table 2 - Average Monthly Delivery Charge Compariosn - Single Family Direct vs. Multi Family Master Metering

A	B	C	D	E	F	G	H	I	J	K
			Monthly Usage (Ccf)		Ccf Block			Total Delivery Charges Per:		
Dwelling	Meter			Per	4	50	Over 50			
Type	Type	Households	Total	Household	$15.54000	$0.37255	$0.10081	Customer	Household	
				(D / C)	**(Note 1)**	**(Note 2)**	**(Note 3)**	**(F + G + H)**	**(I / C)**	
Single Family	Direct	1	89.8	89.8	$15.54	$17.14	$4.02	$36.69	$36.69	
Multi-family	Master	4	359.3	89.8	$15.54	$17.14	$31.18	$63.86	$15.97	**(Note 4)**

Notes

1. The first block of gas is the basic service charge of $15.54, which includes up to 4 Ccf of gas.
2. The second block of gas is priced at $0.37255 per Ccf for up to 46 Ccf.
3. The third (tail) block of gas is priced at $0.10081 per Ccf for all usage over 50 Ccf (4 + 46).
4. In the case of the master metered multi-family dwelling, the individual household is not billed by NFG; the cost of gas service may be included in rent, passed through separately by the landlord, or sub-metered.

Source: Company Tariff at Leaf 149.

As shown in column I, the single family customer who is individually metered incurs monthly delivery charges of $36.69; while the four households occupying the multi-family master metered dwelling each would pay only $15.97 a month (assuming the cost of delivery was passed through by the landlord equally to each tenant). Yet, as shown in column D, all five households in Table 2 (1 single family plus 4 tenants in the multi-family dwelling) consume the same quantity of gas monthly: 89.8 Mcf. Why are single family customers paying more than double for consuming the same amount of gas as tenants in a

multi-family dwelling? The answer lies in the way the two dwellings are metered for gas service: the single family dwelling is served by a meter that calculates one household's gas usage (89.8 Ccf); while the multi-family dwelling is served by one meter that calculates a single total usage amount (359.3 Ccf) for all four households. Meanwhile, the same usage block design and rates are used for both the single family dwelling customer and the landlord of the multi-family dwelling. As a result, the total usage of the individual tenants in the multi-family dwelling is combined (89.8 * 4 Ccf), and the majority of landlord's gas delivery will be priced in the "tail" or last block of energy at $0.10081 per Mcf because all usage over 50 Ccf is priced at that rate. Additionally, the landlord of the multi-family dwelling will pay only one basic service charge for the four tenants. However, the single family dwelling customer's usage will be paid for by that customer alone, and the majority of this customer's bill is priced in the higher cost blocks of energy.

The bottom line is that as explained in Table 2, mixing customers of different meter types makes it nearly impossible to analyze the overall usage characteristics of households in the residential class, and results in disparate utility costs across the residential class based solely on the type of dwelling they live in.

Q. IS THE MIXING OF INDIVIDUALLY AND MASTER METERED CUSTOMERS IN SC1 CONSISTENT WITH STATE POLICY?

A. No. As understandable as this practice has been traditionally, two recent State policy imperatives that require consideration of alternative rate designs are being impeded by the mix of individually and master metered customers in SC1. The first is the need to implement the Commission's May 19, 2016 *Order Adopting Low Income Program Modifications and Directing Utility Filings* in Case 14-M-0565 (the Low Income Order). As the Low Income Order Panel points out in testimony, the Company's increased revenue requirement resulting from the Low Income Order is either $2.8 million or $3.9 million, depending upon the Commission's answer to the Company's Low Income Order Petition. (Low Income Order Panel testimony at 4 – 5). The mix of individually and master metered customers in SC1 hinders the implementation of alternative rate design strategies that could help the Company provide the additional level of benefits for low income customers required by the Low Income Order.

The second policy imperative being impeded by the mix of individually and master metered customers in SC1 is that of the State's "Clean Energy Goals" of reducing greenhouse gas (GHG) emissions by 40% from 1990 levels by 2030, and 80% by 2050 (2015 New York State Energy Plan Overview at 2), the gas utility implementation aspect of which was contemplated in the Commission's Order Adopting Regulatory Policy Framework and Implementation Plan (the Track One Order) in Case 14-M-0101 (the REV Proceeding):

> *"Utility programs should also become more oriented toward demand reduction. Efficiency measures that produce demand reduction less expensive than equivalent capacity purchases should be pursued where possible.* ***We note here that although REV concentrates on the electric industry, it is our expectation that utilities also continue and evolve their gas energy efficiency efforts.****"*
>
> (Track One Order at 79, **emphasis added**)

The mix of individually and master metered customers in SC1 hinders the implementation of alternative rate design strategies that could help achieve gas emission reduction consistent with the Clean Energy Goals of the State Energy Plan and contemplated by the REV proceeding's Track One Order. Because of the inherent non-homogeneity of the members of the SC 1 class, new rate design strategies would be highly problematic. For example, the adoption of inclining block rates for SC1 would unduly harm those class members who were served by a master meter, since at very low levels of their own *household* usage they would likely be charged much higher volumetric delivery rates than they currently experience. Conversely, the opposite is now experienced by individually metered low usage members of SC1 (many of whom are low income customers) because they are unfairly penalized based on how metering is billed for their dwelling type while non low income SC1 customers occupying residences served by master meters in multi-family dwellings might easily pay less than half the delivery charges for the same overall usage in the dwelling.

3. Increasing number of high usage, non-residential customers in the residential class of service

Q. WHAT ARE THE EFFECTS OF THE INCREASING NUMBER OF HIGH USAGE, NON-RESIDENTIAL CUSTOMERS (SC1 NON-RESIDENTIAL CUSTOMERS) IN THE RESIDENTIAL CLASS OF SERVICE?

A. In Case 07-G-0141, changes in rate design that, among other things, lowered the tail block delivery rate for SC1 significantly below the second block rate in SC3, incentivized many religious and not-for-profit customers who had been eligible for service under SC1, but historically obtained their service under Service Class No 3 (SC3, General) to switch to SC1. (Direct Testimony of Thomas J. Clark, Case 07-G-0141 at 26-29). Since 2007, the result has been that SC1 customers whose annual usage is greater than 1,000 Mcf has increased from 0 to 2,021 customers. By 2015, non-residential customers obtaining service in SC1 likely consumed at least 8.6% of the energy delivered under SC1, although they only comprised .5% of SC1 customers in 2015. (Filing Letter at 14)

Q. WHY IS THE MIGRATION OF ELIGIBLE NON-RESIDENTIAL CUSTOMERS FROM SC3 TO SC1 IMPORTANT?

A. The purpose of my testimony is not to determine whether eligible non-residential customers migrating from SC3 to SC1 are achieving a "windfall" at the expense of other ratepayers. Rather, it is to bring to light an important consequence of mixing an increasing

percentage of non-residential customers with traditional residential customers under the SC1 classification. If mixing master metered with individually metered customers complicates any future effort to redesign SC1 rates, mixing in non-residential customers on top of that makes SC1 rate re-design virtually impossible. Imagine the example in which inclining block rates were adopted: such a re-design would be disastrous for SC1 non-residential customers – not because they are inherent wasters of energy, but because they are in the wrong class. Conversely, traditional residential customers could realize substantial savings if they responded to a new inclining block rate design by further reducing energy usage. It should therefore be evident that, at least in the long run, a growing mix of residential and non-residential customers within the SC1 class is not likely to be compatible with efforts to update rate designs that are logical, just and reasonable for all the members of the SC1 class.

Q. WHAT ACTION DO YOU RECOMMEND SHOULD BE TAKEN TO ADDRESS THIS SITUATION?

A. I recommend creating one or more new service classes for master metered two-to-four family dwellings and (current) SC1 non-residential customers. Consideration should be given as to whether it is appropriate to mix these two types of customers in the same class. If not, separate classes should be created: one for master metered two-to-four family dwellings; the other for (current) SC1 non-residential customers.

4. Rate Design

Q. PLEASE DISCUSS THE PROBLEM OF RATE DESIGNS THAT FEATURE HIGH FIXED BASIC COSTS OF SERVICE (BASIS SERVICE CHARGES) AND DECLINING BLOCK RATES FOR GAS DELIVERY SERVICE.

A. The Company's rate designs feature high fixed costs of basic service and declining block rates for delivery service.

(i). High Fixed Costs of Basic Service.

The Company's monthly fixed charge for basic service (known officially as the "monthly minimum charge") is currently $15.54, which in its filing in this proceeding the Company proposes to raise to $19.66, representing a 27% increase. (Exhibit ___WDY-03, Page 1). If granted, basic service charges would comprise 20% of the typical bill for customers at a monthly usage level of 100 Ccf, up from 17% currently. (Exhibit ___WDY-03, Page 1)

(ii). Declining Block Rates.

The Company's volumetric charges for delivery vary with the amount of gas a customer consumes. The volumetric charge is significantly lower (73%) for all monthly usage over 50 cubic square feet of gas (Ccf) than it is for the first 50 Ccf. This design sends customers the "price signal" that the cost of delivery declines as more gas is used, and thus arguably incentivizes higher usage rather than conservation. According to the United States Environmental Protection Agency (EPA):

"Some rate designs, such as declining block rates and bill adders, send price signals that mask the true cost of incremental units of energy and thus can encourage more rather than less energy consumption."[2]

It is also well established that rate designs based on high fixed basic service charges and flat and declining block rates for delivery service create affordability problems for low income customers, and act as a disincentive to conservation and energy efficiency initiatives.[3]

Q. IS THERE A SPECIFIC PROBLEM CREATED FOR LOW-INCOME CONSUMERS BY THE COMPANY's PROPOSED RATE DESIGN?

A. Yes. The specific problem with the Company's rate design that its low income customers face in this proceeding is that they will have little opportunity to mitigate the cost of the proposed increase in volumetric delivery rates and no opportunity to avoid the cost of increased basic service charges. Consider the example of a low income customer whose monthly usage is 89.8 Ccf of gas. As the previous example in Table 2 makes clear, that customer would have to reduce monthly consumption by 39.8 Ccf (44%) before reaching the highest volumetrically-priced block of gas; the "penultimate", or second-to-

[2] National Action Plan for Energy Efficiency (2009). *Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design*. Prepared by William Prindle, ICF International, Inc. www.epa.gov/eeactionplan.
[3] National Consumer Law Center, *Utility Rate Design: High Utility Fixed Charges Harm Low Income, Elders and Households of Color*, av'l here: http://www.nclc.org/energy-utilities-communications/utility-rate-design.html.

last block at $0.37255 per Ccf. Worse, they would have no ability to use conservation measures to mitigate the proposed 27% increase in fixed cost of basic service.

The unresponsiveness to conservation and efficiency measures embedded in the Company's high fixed cost of basic service / declining block rate design, as proposed in the Company's filing in this proceeding (Exhibit__(COSRD-11) Schedule 1 Page 1 of 10) is illustrated in Table 3:

Public Utility Law Project of New York, Inc. - Case #16-G-0257 (National Fuel Gas)

Table 3 - Savings? Reduced Consumption vs. Total Delivery Charges at Proposed Rates

A	B	C	D	E	F	G
Monthly Usage (Ccf)		Ccf Block			Total Delivery Charges	
		4	50	Over 50	Amount	Percent
(Ccf)	Reduction	$19.66000	$0.38845	$0.11671		Savings
		(Note 1)	**(Note 2)**	**(Note 3)**	**(C+D+E)**	**(Note 4)**
89.8	0%	$19.66	$17.87	$4.64	$42.17	0.0%
80.8	-10%	$19.66	$17.87	$3.60	$41.13	2.5%
71.8	-20%	$19.66	$17.87	$2.55	$40.08	5.0%
62.9	-30%	$19.66	$17.87	$1.50	$39.03	7.5%
53.9	-40%	$19.66	$17.87	$0.45	$37.98	9.9%
44.9	-50%	$19.66	$15.89	$0.00	$35.55	15.7%

Notes

1. The first block of gas is the basic service charge of $19.96, which includes up to 4 Ccf of gas.
2. The second block of gas is priced at $0.388449 per Ccf for up to 46 Ccf.
3. The third (tail) block of gas is priced at $0.116708 per Ccf for all usage over 50 Ccf (4 + 46).
4. Savings calculated by subtracting total delivery charges at reduced consumption from total delivery charges at 89.8 Ccf.

Source: Exhibit__(COSRD-11) Schedule 1 Page 1 of 10

Plainly, high fixed costs of basic service combined with the steeply declining block rates for delivery proposed by the Company would make it extremely difficult for conservation-

minded customers to achieve meaningful savings on their delivery charges. Such customers would be required to reduce monthly consumption by over forty percent (40%) just to achieve a ten percent (10%) reduction of their delivery charges. On top of that, any investment that a customer might make in energy efficiency measures automatically incurs a significantly higher payback period than would be the case under a rate design that sent price signals that truly encouraged conservation and energy efficiency.

Q. DO THE COMPANY'S PROPOSED RATE DESIGN AND BASIC SERVICE CHARGE INCREASE HAVE DISPROPORTIONATE NEGATIVE EFFECTS UPON LOW INCOME CUSTOMERS?

A. Yes. The stakes for the Company's low income customers in this regard are very high. As already described, by the Company's count there are at least 88,208 low income customers served in the eleven counties of its service territory (Company response to UIU-3). For low income households – those with less than $35,000 of income – the 30% Housing Cost Burden has persisted at 65% (Chart 1). Fully 36% of low income households in the Company's service area spend at least 50% of their income on housing costs (Table 1). With such high percentages of Housing Cost Burden it's almost certain that they would be disproportionately harmed by the rate increases proposed in this case. The magnitude of the increase is bad enough; worse is that high fixed costs of basic service and declining

block rates make it nearly impossible to use conservation or energy efficiency measures to reduce delivery charges.

Q. WHAT ACTION DO YOU RECOMMEND SHOULD BE TAKEN TO ADDRESS THIS SITUATION?

A. Recognizing that current rate designs have been in place for decades, and that I and other non-Company parties lack much of the information needed to make fully informed recommendations, I recommend that a multi-party working group be established in the context of this rate proceeding to consider the advisability of having the Company adopt alternative residential class rate designs (Green Rate Designs), the purpose of which would be to achieve greater affordability for all average and lower usage customers, including low income customers, through the implementation of designs that incentivize energy conservation and efficiency and support New York State's declared goal of reducing greenhouse gas (GHG) emissions 40% by 2030 and 80% by 2050.

In the following two examples (Exhibit ___WDY-07) I present alternative rate designs based on inclining block rates. My intent is to illustrate how rates could be re-designed to:

1) Help solve the revenue requirement problem the Company faces in implementing the Low Income Order, and
2) Encourage energy conservation and efficiency which would in turn help achieve the State's GHG reduction objectives for 2030 and 2050.

The first example keeps the monthly basic service charge at $15.54; the second lowers the basic service charge to $10.00, in order to achieve greater alignment between the Company's rate design(s) and the State's goal of achieving a maximum energy burden of 6% of income for low-income customers. The Company's revenue de-coupling mechanism (RDM) is also considered as it could act as a potential offset to the savings that would be achieved by lower usage customers due to the price signals sent to all (especially higher usage) customers to conserve energy.

In both examples, I also make the following assumptions:

1. All SC1 customers with usage levels above 500 Mcf of annual consumption, most-if-not-all of whom are not directly metered single household residential customers, are transferred to another class of service.
2. Though the SC1 class includes master metered customers, none are considered as I was unable to find information in the Company's filing in this proceeding to account for these customers. I have submitted follow up I/Rs to the Company which may shed some light on how these customers can be identified. However, it is clear that this is one way in which a collaborative effort as described above would help provide the further information needed to determine the usefulness of exploring alternative rate designs.

I used the above assumptions and the Company's Bill Frequency Report of SC1 customers with twelve months of billing as included with its filing letter in this proceeding (Filing

Letter, Attachment B, Page 1) to test both examples of inclining block rates. Exhibit ___WDY-07, Page 1 re-creates the Bill Frequency Report and adds a column calculating monthly Ccf block. Exhibit ___WDY-07, Page 2 calculates the monthly and annual delivery revenues that would be generated by current rates under the current rate design for the customers included on the Bill Frequency Report. Exhibit ___WDY-07, Page 3 re-calculates delivery revenues retaining the current basic service charge of $15.54, but changes the second block rate to $0.10081 per Ccf (the current tail block rate). In this exhibit I also add an additional third (new penultimate) block, the rate of which is set to $0.37255, the existing second (current penultimate) block rate. Finally, I set the tail block rate to $0.54765, 147% of the current penultimate block.

As can be seen from Exhibit ___WDY-07, Page 3, all customers whose annual usage is at or below 120.9 Mcf (monthly usage of 100.8 Ccf) experience lower delivery charges under the alternative rate structure. Importantly, 120.9 Mcf of usage is within the Bill Frequency Report's 100 – 150 block of usage, which, cumulatively, includes 334,414 out of 394,444 (about 85%) of customers on the Bill Frequency Report. Given, however, that the average usage of customers in this block is 120.9 Mcf, I estimate that roughly 40% of the customers in the block experience lower total annual delivery charges under the alternative rate design of this example, which leads me to estimate that about 258,313 out of 394,444 (about 65%) of the customers on the report would experience annual delivery rates lower than those they experience under the current rate design.

Other results from the re-design under this alternative include:

1. The revenue requirement for the class is achieved – at least as reflected by the billing of customers included on the Bill Frequency Report (total delivery revenue = $169,217,219 versus $169,153,115 for the current rate design).

2. The annual savings to the 65% of customers who average less than 120.9 Mcf of consumption is $20,007,605 – approximately 15% less than they pay under the current rate design.

3. The annual percentage savings for the usage block comprising the largest number of the Company's residential customers (169,229 or 43% of the report total) is far higher: 25%. It is likely therefore that the savings of the median number of customers (50% or 197,222) is comparable.

4. Crucially, to the extent that low income customers would experience savings under this alternative due to consumption below 120.9 Mcf, they would experience rate relief that could serve to reduce the revenue required to provide them discounts under the Low Income Order's requirements. In fact, depending upon the forthcoming Commission ruling on the Company's Low Income Order Petition, the net savings to low income customers under this rate design could exceed the Company's estimate of the revenue required to implement the Low Income Order: $3,334,467 (versus the Low Income

Order's funding cap based on 2% of sales, which would equal $2,768,308). The net savings due to rate re-design in this first example would also equal about 85% of the Company's higher estimate of the revenue required to implement the Low Income Order: $3,334,467 (versus the Low Income Order's funding cap based on 6% of energy burden, which would equal $3,919,464).

5. The delivery revenue necessary in this example to generate savings to customers with annual usage of less than 120.9 Mcf is entirely made up by charging higher volumetric rates to high usage customers. Which is consistent with the State's goal to promote conservation and reduce demand. To reiterate, however, substantially all high usage, non-residential customers are assumed to have been transferred to another class of service for the purposes of this example. Some of the remaining customers in this experimental SC1 block whose usage is above 120.9 Mcf are likely to be master metered two-to-four family dwellings that would also need to be excluded from SC1 in a fuller study of this subject, and thus the revenue generated by higher volumetric charges to high usage customers is likely to be less than $3,334,467. However, it is still reasonable to assume a substantial contribution to rate relief for low income customers, and therefore a reduction in the revenue requirement that would need to be generated to carry out the Low Income Order could be made by this rate re-design.

6. If re-designing rates using inclining block rates is to achieve the two policy objectives I have set forth; that is, both savings to low usage (including low income) customers and the fostering of energy conservation and efficiency by high usage customers responding to the price signals sent by higher volumetric tail rates, then it must be assumed that such customers will, in some measure, respond in ways that reduce their consumption. In this regard, it is critical to understand how the Company's revenue decoupling mechanism, or RDM, could impact the assumed outcomes of redesigning rates under this alternative. Through the RDM, the Company is provided a mechanism that ensures it will achieve its authorized revenue requirement (in this example, the total revenue under the existing rate design - $169,153,115). The Company's RDM is designed so that any shortfalls in a class's revenue requirement are charged at the tail block rate. Under this alternative, the tail block has the highest rate: $0.54765. Therefore, every Ccf of revenue requirement shortfall will be added to customer bills at that highest rate. Obviously, the risk is that some of the savings realized by customers under the alternative set forth in this example could be offset, perhaps materially, by RDM adjustments that make up the revenue the Company lost because customers responded to higher volumetric tail rates by reducing consumption. Herein lies another aspect of this topic that requires further information and study by a larger, preferably collaborative, group.

Example 2 (Exhibit ___WDY-07, Page 4) differs from the Example 1 (Exhibit ___WDY-07, Page 3) in that the monthly fixed cost of basic service is reduced to $10.00. To achieve the revenue requirement under such a scenario, the penultimate (third) block rate is increased to $0.54020, 147% of the current penultimate (second) block rate of $0.37255. The tail block is raised to $0.63334, 170% of the current penultimate block rate.

Once again, all customers whose annual usage is at or below 120.9 Mcf (monthly usage of 100.8 Ccf) experience lower delivery charges under the alternative rate structure. The revenue requirement for the class is achieved, with total delivery revenue of $169,334,514 versus $169,153,115 for the current rate design. For the 65% of customers who average less than 120.9 Mcf of consumption – i.e., conservation-focused "low-usage" customers – the annual savings generated is approximately 18% less than they currently pay the Company (i.e., a savings of $25,330,666). Additionally, 43% of the Company's residential customers would experience annual percentage savings of 34% on their bills (this group of 169,229 households comprises the Company's largest usage block). The savings of the median number of customers covered by the report (50% or 197,222) is likely comparable.

The net savings to low income customers in Example 2 could exceed the Company's estimate of the revenue required to implement the Low Income Order under either outcome of the Company's Low Income Order Petition: $4,221,609 versus $2,768,308 - the cap based on 2% of sales, or $3,919,464 - the cap based on 6% of energy burden of $3,919,464.

It is important to note that in Example 2, the delivery revenue necessary to generate savings to customers with annual usage of less than 120.9 Mcf, was derived by charging higher volumetric rates to customers with large usage. Consequently, those affected higher usage customers are more likely to respond in ways that would reduce their consumption significantly. Therefore, there is likely to be more of an RDM offset to savings, and in this example, the tail block rate is even higher than in the first alternative: $0.63334. Example 2 thus presents a greater risk that a material amount of the savings realized by lower usage customers could be offset by RDM adjustments to make up revenue lost to the Company through the rational responses of the heaviest users moving to conservation measures to lower their bills.

In summary, the two examples above illustrate ways that alternative approaches to rate design could help address the State policy imperatives of improving utility affordability for low income customers and reducing the State's GHG emissions 80% by 2050. The examples presented in Exhibit ___WDY-07 are for illustrative purposes and would require significantly more study and access to more granular information to be proposed to be implemented as alternatives to the Company's current rate design. The recommendation arising here from these two examples is simply that the advisability of using such alternative rate designs should be the subject of a collaborative study among the parties to this proceeding because of the potential benefits and heightened alignment with two of the State's key energy policies. In that way, the benefits of a wider range of viewpoints and of fuller information and expertise can be brought to the discussion.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation (New York), for Gas Service.

CASE 16-G-0257

REBUTTAL TESTIMONY OF WILLIAM D. YATES, CPA

FOR

PUBLIC UTILITY LAW PROJECT OF NEW YORK, INC.

Dated: October 4, 2016

Q. ARE YOU THE SAME WILLIAM D. YATES WHO SUBMITTED DIRECT TESTIMONY ON AUGUST 26, 2016 IN THIS PROCEEDING ON BEHALF OF THE PUBLIC UTILITY LAW PROJECT OF NEW YORK, INC. (PULP)?

A. Yes.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. My rebuttal testimony discusses the performance incentive mechanism proposed by Staff to reduce residential service terminations and arrears. I conclude that this proposal is incomplete because it does not require independent verification that all terminations used to establish the mechanism's baseline data comply with the Home Energy Fair Practices Act (HEFPA); nor does it require independent verification that terminations conducted in subsequent measurement periods comply with HEFPA. I assert that no performance incentive mechanism should be implemented without requiring such independent verification.

Q. ARE YOU SPONSORING ANY EXHIBITS IN SUPPORT OF THIS SUPPLEMENTAL TESTIMONY?

A. No.

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE STAFF'S PERFORMANCE INCENTIVE MECHANISM TO REDUCE TERMINATIONS.

A. The Staff's proposal for the Company recommends a maximum positive revenue adjustment (PRA) of $0.6 million if the Company achieves both of the following targets for the rate year: an uncollectible level of no more than $4.6 million and residential service terminations for nonpayment of no more than 12,700 customers. If uncollectibles rise to $14.8 million or more and terminations rise to 25,000 customers or greater, Staff recommends a maximum negative revenue adjustment (NRA) of $0.6 million should be applied. Staff proposes partial positive or negative revenue adjustments are possible if targets are partially met (Staff Consumer Services Panel Testimony, Page 34 and Exhibit ___ (CSP-6)).

Q. DO YOU THINK STAFF'S PROPOSED PERFORMANCE INCENTIVE MECHANISM TO REDUCE TERMINATIONS SHOULD BE ADOPTED IN ITS CURRENT FORM?

A. No. The Staff proposal is not satisfactory because it would implement an incentive mechanism to reduce terminations without first demonstrating that all terminations conducted by the Companies are already in compliance with HEFPA. PULP has expressed this same concern about similar proposals made by Staff in the recent National Grid gas and Con Edison rate cases[1].

[1] Rebuttal testimony of William D. Yates, CPA, Cases 16-G-0058/16-G-0059 at 6-14; Cases 16-G-0060/16-G-0061 at 5-10.

As a generic principle, PULP has expressed support for incentive mechanisms for reducing terminations that require an independent verification that all terminations conducted during a measurement period were in compliance with HEFPA and represent a reduction from fully-compliant terminations in an appropriate baseline or prior measurement period (Case 14-M-0101, *Reply Comments in Response to the Staff White Paper on Ratemaking and Utility Business Models (Track Two)* at 11). If such verification could be achieved, PULP would be supportive of a suitable incentive mechanism to enhance customers' ability to retain essential service beyond the statutory payment agreement and termination provisions of HEFPA. However, it would be inappropriate to reward the Companies for "reduced" terminations in any years that either 1) included non-HEFPA compliant terminations or, 2) were lower than prior years because prior years included non-HEFPA compliant terminations.

Q. ASSUMING AN INDEPENDENT VERIFICATION DETERMINED THAT ALL TERMINATIONS DURING A SUITABLE BASELINE PERIOD WERE HEFPA-COMPLIANT, WOULD YOU APPROVE OF THE INCENTIVE MECHANISM PROPOSED BY STAFF?

A. Yes. The approach Staff recommends in this proceeding is sound for several reasons:

1. It includes both PRAs and NRAs based on annual targets for terminations and uncollectibles, thereby setting incentives that reward good performance while discouraging poor performance.

2. It includes both terminations and uncollectibles. Staff requires that terminations be reduced without creating more uncollectibles. To achieve such a goal, the Company must ultimately work with customers who are having difficulty paying their bills by, for example:
    a. negotiating affordable DPAs,
    b. enrolling them in payment assistance programs (if applicable), and/or
    c. providing the customer with information about HEAP or energy assistance (one-shot) grants.

   In this way, Staff's proposal aligns with PULP's position that *positive incentive mechanisms must be based on performance that exceeds the statutory protections required by HEFPA.*

3. It sets targets for terminations and uncollectibles based on four standard deviations from normalized seven year averages. (Staff Consumer Services Panel Testimony, Exhibit ___ (CSP-5)), better aligning incentives with the Company's terminations and uncollectibles behavior over a full business cycle. By setting targets four standard deviations above or below "average" over such a period, the Staff proposal would require performance that "deviates" meaningfully from average before the Company could be eligible for a PRA in the case of positive results or subject to an NRA in the case or poor performance.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation (New York), for Gas Service.

CASE 16-G-0257

SUPPLEMENTAL TESTIMONY OF WILLIAM D. YATES, CPA

FOR

PUBLIC UTILITY LAW PROJECT OF NEW YORK, INC.

Dated: August 30, 2016

Q. ARE YOU THE SAME WILLIAM D. YATES WHO SUBMITTED DIRECT TESTIMONY ON AUGUST 26, 2016 IN THIS PROCEEDING ON BEHALF OF THE PUBLIC UTILITY LAW PROJECT OF NEW YORK, INC. (PULP)?

A. Yes.

Q. WHAT IS THE PURPOSE OF THIS SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to report on my findings after review of Company response to PULP-14 Attachment 1 (Redacted) (Exhibit ___WDY-08) which support a recommendation I made in my direct testimony. Judge Lecakes approved the filing of this supplemental testimony by e-mail distributed to all parties on Friday, August 26, 2016.

Q. ARE YOU SPONSORING ANY EXHIBITS IN SUPPORT OF THIS SUPPLEMENTAL TESTIMONY?

A. Yes. I include two exhibits with this testimony. Exhibit ___WDY-08 is the Company's response to I/R PULP-14. I/R PULP-14 requested the Company to provide a copy of any analysis prepared by the Company within the last year comparing charges of ESCOs with charges for default gas service, for both residential and non-residential customers. Exhibit ___WDY-09 analyzes further the data presented in the Company's response to I/R PULP-14.

Q. DOES THE COMPANY'S RESPONSE TO I/R PULP-14 SUPPORT YOUR RECOMMENDATIONS PROVIDED IN YOUR DIRECT TESTIMONY?

A. Yes. In my direct testimony, I recommended that the Company should extend the HEAP customer discount to eight months as it originally proposed in its customer service panel testimony should the Low Income Order petition not be answered by the effective date of the order in this proceeding. This recommendation is now further supported after my review of the Company's response PULP-14 Attachment 1 (Redacted) (Exhibit ___WDY-08). The Company's response PULP-14 Attachment 1 (Redacted) shows that low income customers obtaining gas supply from an ESCO paid ever-increasing percentages more for their gas than they would have from the Company. By extending the HEAP customer discount to eight months as the Company originally proposed, and as I continue to recommend, the Company will help ameliorate some of the effects of the unaffordability crisis, as driven by the economy and utility, as explained in my direct testimony, as evidenced by the Company's data in response PULP-14 Attachment 1 (Redacted), and as further explained in my supplemental testimony below.

Q. PLEASE EXPLAIN THE DATA IN COMPANY'S RESPONSE PULP-14 ATTACHMENT 1 (REDACTED).

A. The Company's response PULP-14 Attachment 1 (Redacted) (Exhibit ___WDY-08) shows that, over consecutive twelve month periods (TMEs) ending from December, 2014 through April, 2016, low income customers obtaining gas supply from an ESCO paid ever-increasing

percentages more for their gas than they would have from the Company. ESCO supplied gas cost 14.2% more than Company supplied gas for the TME ending December, 2014. By March, 2016, ESCO supplied gas was higher priced by 25.6%. And for the TME ending April, 2016, the cost of ESCO supplied gas was $2,637,783 or 25.0% more than Company supplied gas. (Exhibit ___WDY-08, Pages 3-4). Exhibit ___WDY-08 also shows that for the TME ended April, 2016, most of the ESCO gas volume sold to low income customers was at least 44% higher in price than Company supplied (Page 6). In its description of that fact, the Company highlights that "*10.32% of Low Income residential NGS customer usage has paid 55.1% more than NFG costs*" and "*50.17% of Low Income residential NGS customer usage has paid 44.6*% more than NFG costs". <u>In other words, more than half of the gas volume ESCOs supplied to the Company's low income customers during the period in question was priced at least 44.6% higher than gas supplied by the Company</u>.

Q. PLEASE EXPLAIN HOW THE ANALYSIS YOU PROVIDE IN EXHIBIT ___WDY-09 SHOWS THAT ESCOS ARE A CONTRIBUTING FACTOR TO THE UNAFFORDABILITY CRISES EFFECTING LOW INCOME CUSTOMERS.

A. In Exhibit ___WDY-09, I provide analysis of the data in Company's response PULP-14 Attachment 1 (Redacted) to support my conclusion that the vast majority of low income customers obtaining their supply from an ESCO paid more than they would have if they had purchased it from the Company. Using average monthly bills as a proxy for monthly customers, I calculated

that 11,728 customers (77.1% of the total of 15,219 average monthly customers) paid $2,787,591 (34.9%) more to an ESCO for gas than they would have if they had been supplied by the Company. Monthly, the typical customer in this group paid $19.81 more by choosing ESCO supply. Only a small minority saved money: 3,491 customers (23%) saved an average of 5.8% or $149,808. In this group, the typical customer saved $3.58 monthly.

In sum, the Company's response PULP-14 Attachment 1 (Redacted) shows that ESCOs are charging the Company's low-income customers an ever-increasing percentage more for their gas supply each month. These exorbitant prices on more than half the volume of gas the ESCOs sell are contributing to the utility affordability problems of the Company's low income customers because they result in an increase to monthly bills of the vast majority of low income customers by an average of almost $20 per month. This amount exceeds, on an annualized basis, the total assistance provided by the Company's low income discount to HEAP recipients by 284% ($20 * 12 = $240 divided by $12.50 * 5 = $62.50). Therefore, for these customers, ratepayer funded low income discounts serve merely to subsidize ESCO overcharging of low income customers - and only partially at that.

Q. WHAT ARE YOUR CONCLUSIONS BASED UPON REVIEW OF THE COMPANY'S RESPONSE PULP-14 ATTACHMENT 1 (REDACTED)?

A. Company's response PULP-14 Attachment 1 (Redacted), as analyzed by me in (Exhibit ___WDY-09), demonstrates that ESCO actions are exacerbating utility unaffordability for the

Company's low income customers. This finding adds significant support for my recommendation made in direct testimony that the Company should adopt the eight-month discount for HEAP recipient customers as originally proposed in its customer service panel testimony, should its Low Income Order Petition not be answered by the effective date of the order in this proceeding in a manner that would provide more assistance for low-income customers. Overcharging by ESCOs is a material additional factor compounding the problems the Company's low income customers are having paying their bills. Without the kind of additional assistance rendered by the Company's proposal to extend HEAP customer discounts to eight months, more of these customers are likely to fall into arrears and face increased risk of termination for nonpayment. Although the three months of additional discounts are likely to primarily act as a further subsidy of ESCO overcharging, remedies for this problem are beyond the scope of this testimony and proceeding, and the alternative of no extension wouldn't provide sufficient assistance to the Company's HEAP discount customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

A.L.J. LECAKES: Now we can turn to Mr. Yates's exhibits.

MS. JORGENSEN: Yes. The corrected testimony has five exhibits titled WDY-01, WDY-03, WDY-04, WDY-05, WDY-07.

A.L.J. LECAKES: I have on my exhibit list one -- WDY1, 3, 4, 5, 6, and 7. Is that correct?

MS. JORGENSEN: My apologies, Your Honor. WDY6 is also requested to be added to --

A.L.J. LECAKES: Marked for identification?

MS. JORGENSEN: -- incorporated into the record.

A.L.J. LECAKES: Okay. We will mark WDY1 as 169, WDY3 as 170, WDY4 as 171, WDY5 as 172, WDY6 as 173, and WDY7 as 174. Other exhibits?

MS. JORGENSEN: Yes, with the supplemental testimony there are two exhibits, WDY8 and WDY9.

A.L.J. LECAKES: On the exhibit list that PULP provided, WDY9 was listed before WDY8. Was there any particular reason why it was done that way?

MS. JORGENSEN: No.

A.L.J. LECAKES: Is there any reason to have it in that order instead of the numerical order of 8

and 9?

MS. JORGENSEN: No, Your Honor. I tried to fix that. I'm not sure --.

A.L.J. LECAKES: Okay. Well --

MS. JORGENSEN: Check --

A.L.J. LECAKES: We'll mark WDY8 as 175 and WDY9 as Exhibit 176. Does that conclude PULP's offer of affidavits and exhibits for now?

MS. JORGENSEN: Yes, Your Honor.

A.L.J. LECAKES: As I noted earlier, Multiple Intervenors is not here. We will accept their affidavits later in the hearing. At this point, I would like to call forward to the stand Mr. Richard Ford. Mr. Richard Ford, please approach and take a chair here. We're going to take a quick recess while he does that so that the court reporter can adjust the microphones. How about we reconvene in five minutes.

(Off the record)

A.L.J. LECAKES: Okay. Let's go back on the record. I call to the stand Mr. Richard Ford. Could you please identify yourself by your name and your -- either your business address or the address by which you are representing yourself in this case.

MR. FORD: My name is Richard W. Ford.

I'm an individual residential customer of National Fuel. I live at 7601 Transit Road in East Amherst, New York.

A.L.J. LECAKES: Mr. Ford, could you please stand and raise your right hand? Do you swear or affirm that the testimony you're about to give in this proceeding is the whole truth?

MR. FORD: Yes, sir.

RICHARD FORD; Sworn

A.L.J. LECAKES: Thank you, you may be seated.

EXAMINATION

BY A.L.J. LECAKES:

Q. Good afternoon Mr. Ford. I'm going to ask you some questions to get the documents that you previously filed into our hearing record. As you mentioned, you're a residential customer of National Fuel Gas. Correct?

A. Yes.

Q. And you are appearing in this case as an NFG customer?

A. Yes, Your Honor.

Q. Could you tell us briefly about your educational background?

A. I started out in engineering at

Northeastern University in Boston. I have a mathematics degree from Eastern Nazarene College in Quincy, Massachusetts. I have an MBA from Keller Graduate School of Business.

Q. And do you have any work background or professional experience that's relevant to your analysis that you've done in this case?

A. I'm a certified energy manager for the Association of Energy Engineers and I've worked for about 25 years as an Energy Conservation Consultant.

Q. Your particular interest in this case involves the magnitude of NFG's requested rate increase and the amount of the customer fixed charges. Is that correct?

A. Yes, Your Honor.

Q. On August 26, you filed 3 documents in this proceeding. Correct?

A. Yes, Your Honor.

Q. And then by email to me and the parties this past Monday, October 3rd, you served an additional excel file. Is that correct?

A. It was an update of one of the previous files.

Q. Okay. Mr. Ford, I took the liberty of

printing out your documents and putting them together in one file packet and I've now distributed that file packet to everyone including you. Do you have that packet before you?

A. Yes, Your Honor.

Q. And have you had a chance to look at -- through those documents?

A. Yes, Your Honor.

Q. And is that a correct list of the -- a correct printout of the documents that you supplied to me?

A. Yes, they're well done in order.

Q. Thank you. And what exhibit number did we leave off of? 177? Okay. We'll mark this packet as Exhibit 177 for identification.

Now Mr. Ford, for Exhibit 177, did you prepare these documents yourself?

A. Yes, Your Honor.

Q. And what did you do to prepare these documents or how did you prepare them?

A. I started out with four years of my own utility bills, put them all into excel spreadsheets and then did a lot of different analyses on them.

Q. And some of the analyses that you used were files or information that you obtained from discovery

responses that the company gave to other parties in this proceeding. Is that correct?

A. Yes, Your Honor.

Q. And those are marked on the pages that are in this exhibit where that happens?

A. Yes, Your Honor.

Q. Now the first two sets of spreadsheets that you supplied back when testimony was filed in August, you explained what they are on this first page here that has the title Customer Charges. Is that correct?

A. Yes, you -- you asked some questions about the embedded costs of service and National Fuel responded with Exhibit COSD-1 Schedule 1. So the first two columns of figures are the exact figures that were copied from National Fuel and I added a third column where I put a zero if I thought the cost item was not a legitimate part of the customer charge. It should be related to the cost for CCF and if it looked like it was possible that it was -- it was a legitimate part of the customer charge, I copied the same number that National Fuel had used. I ended up with the lower figure than they did.

Q. Now you mentioned that the file that you sent this past Monday, October 3rd, was an update to

one of these files?

A. Yes, sir. The latest one -- it says revision three at the end. It has different places of the similar document with the same name as revision one.

Q. Okay. Now your position in this case is that the customer charge -- the fixed charge should be reduced to zero. Is that correct?

A. That is what I'd like to see because that would totally be in agreement with the state's energy policy conformed to the energy vision that would maximize the incentive for people to conserve energy. The previous case with New York State Electric and Gas, the public service commission took a position that there are some genuine costs which are related to the number of -- of residential customers so I did attempt to calculate it -- a figure in several ways of what costs could logically be included as a fixed customer charge.

Q. Okay.

A.L.J. LECAKES: I have no further questions for this witness. Do any of the parties here have any cross examination for Mr. Ford?

MR. FAVREAU: No, Your Honor.

A.L.J. LECAKES: All right. Thank you, Mr. Ford. You are excused. Your documents have been

marked as Exhibit 177 and I will make sure they get on DMM as a single packet so the pre-filed exhibits will no longer be referred to. It will just be this Exhibit 177 for the parties' reference. Thank you.

MR. FORD: Thank you.

A.L.J. LECAKES: Let's go off the record.

[Off the Record]

A.L.J. LECAKES: I turn to the company to call its first witness.

MR. MILLER: Company calls Kevin House.

A.L.J. LECAKES: Thank you. Mr. House, could you please identify yourself by name and your business address?

MR. KEVIN HOUSE: Yes. Kevin House. 6363 Main Street, Williamsville, New York.

A.L.J. LECAKES: Now Mr. House could you please stand and raise your right hand. Do you swear and affirm that the testimony that you're about to give in this proceeding is the whole truth?

MR. HOUSE: I do.

KEVIN HOUSE; Sworn

A.L.J. LECAKES: Thank you. You may

be seated. Mr. Miller, will you be conducting the direct to get the testimony into the record?

MR. MILLER: Yes, Your Honor.

A.L.J. LECAKES: You may proceed whenever you're ready.

THE REPORTER: How do you spell your last name?

THE WITNESS: H-O-U-S-E.

DIRECT EXAMINATION

BY MR. MILLER:

Q. Mr. House, you have in front of you a 26 page document entitled Direct Testimony of Kevin D. House.

A. Correct.

Q. Do you have any changes or corrections to make to that document?

A. No.

Q. If I were to ask you the questions in that document, would your answers be as set forth therein?

A. Yes.

Q. And do you also have in front of you a 54 page document entitled Rebuttal Testimony of Kevin D. House?

A. Yes.

Q. Do you have any changes or corrections to make to that document?

A. No.

Q. If I were to ask you the questions contained in that document, would your answers be as set forth therein?

A. Correct.

MR. MILLER: Your honor, may we have the prepared direct and rebuttal testimony of Mr. House copied into the record as if given orally?

A.L.J. LECAKES: Yes. So for the reporter's purposes that will fall on the company's testimony disk again and that will be House Direct Testimony in the folder Company Direct Testimony as well as in the folder Company Rebuttal Testimony House Rebuttal Testimony.

Revised Direct Testimony of Kevin D. House

Q. Please state your name and business address.

A. My name is Kevin D. House. My business address is 6363 Main Street, Williamsville, New York 14221-5887.

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

A. I am employed by National Fuel Gas Distribution Corporation (“Distribution” or "Company") as an Assistant Vice President with responsibility in the Engineering Services Department.

Q. Please describe your educational background.

A. In 1984, I graduated from Grove City College with a Bachelor of Science degree in Chemical Engineering.

Q. Please describe your experience at Distribution.

A. In August 1984, I began my career with Distribution in the Pennsylvania Division Operations Department. I worked in the Operations Department for 14 years as a Staff Engineer, Construction and Customer Service Supervisor, District Manager and Assistant Superintendent. I transferred to the Pennsylvania Division Engineering Department in 1999 as Staff Engineering Manager. In 2002, I was transferred to New York Distribution Engineering and served as Staff Engineering Manager for both New York and

Pennsylvania Engineering. I was promoted to General Manager in the Engineering Services Department in 2007 and to Assistant Vice President in October 2013.

Q. Please describe your responsibilities as it relates to this testimony.

A. I am responsible for the development and oversight of Distribution's capital budget and for the management of the Company's system modernization effort, generally referred to as its Leak Prone Pipe ("LPP") Replacement Program. I am also responsible for the Company's Distribution Integrity Management Program ("DIMP") and for reporting the Company's Gas Safety Performance Measure results to New York Department of Public Service Staff ("Staff").

Q. Have you previously testified before the New York State Public Service Commission ("Commission")?

A. Yes. I provided rebuttal testimony before the Commission on behalf of Distribution regarding proposed safety penalty mechanisms in Case 07-G-0141.

Q. Have you testified before any other commission?

A. No, I have not.

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

A. I am providing testimony regarding Distribution's Capital Budget and LPP Replacement Program as well as the safety penalty mechanisms that Staff and the Commission have imposed on the Company.

Q. What types of pipe material are included in the Company's LPP Replacement Program?

A. The Company has included unprotected bare steel, unprotected coated steel, protected bare steel, cast iron, wrought iron and certain earlier vintage plastic piping that has exhibited or may be prone to leakage, in its LPP Replacement Program. Inclusion of these materials is consistent with the Commission definition of leak prone pipe in Case 15-G-0151 - Proceeding on Motion of the Commission to Consider Implementation of a Recovery Mechanism to Support the Accelerated Replacement of Infrastructure on the Natural Gas System.

Q. Please describe Distribution's LPP Replacement Program.

A. Distribution began accelerating LPP replacements in the mid-1990's when we implemented our Systematic Replacement Program. The Company designed and developed the program to identify and

prioritize pipeline replacements on a system-wide basis using a comprehensive planning process and planning tools, including our Geographic Information System ("GIS") and Pipeline Replacement Evaluation Program ("PREP"). The Company's LPP Replacement Program is robust and carefully designed to insure the safety and reliability of its system and to control leakage rates on LPP by prioritizing pipeline replacements system-wide. Since 1997, the Company has made significant and consistent progress in this effort, having eliminated approximately 1,795 miles or 47.6% of its leak prone bare steel, cast iron and wrought iron mains and approximately87,030 or 64.2% of its bare steel services under its Systematic Replacement Program.

Q. How does the Company identify projects under its LPP Replacement Program?

A. Each Fall, at the conclusion of the annual leak survey cycle, the Company utilizes its GIS to perform a geographic leak analysis of the entire distribution system to identify areas of concentrated leakage. This analysis assigns a risk factor to each area based on the number and grade of leaks. Our Engineering and Operations management

then review maps of higher priority areas during annual planning meetings held at each operating location, to identify potential pipeline replacement projects, for further development. The planning meetings also identify any system reliability concerns and potential conflicts with planned highway and municipal construction work. A review of standing agenda items insures that all relevant system issues are considered in the Company's pipeline replacement plan for the upcoming construction season. It should be noted that projects containing leaks that pose a potential safety concern, or that are associated with the interruption, or potential interruption, of service to customers, are expedited throughout the year, consistent with the Company's high service standards and commitment to safety.

When selecting projects, smaller scope projects are identified for construction using Company construction crews or the Company's Blanket Pipeline Contractors who are contracted, by geographic area, to supplement Company crews during peak construction periods. For larger scope projects, the Engineering Services Department develops construction plans and cost estimates and prepares a Systematic

Replacement Presentation, including a proposed Bid Plan, which is presented to executive management. The presentation consists of a prioritized project listing including important metrics used in project prioritization such as; PREP scores, outstanding and repaired leaks, number of service interruptions, bare steel services on the project, cast iron footage, etc. After review and approval by executive management, the Engineering Services Department implements the Bid Plan.

Q How has the Company managed its pipeline replacement program to control costs?

A. The Company's philosophy with respect to its Systematic Replacement Program was developed to reduce unit costs, thereby maximizing LPP replacement. In designing pipeline replacement projects, the Company looks to develop larger scope projects with better economies of scale than multiple smaller projects. The Company also maximizes medium pressure replacements to reduce pipe size, which allows insertion of new medium pressure mains, into the larger low pressure mains being replaced, thus reducing excavation and restoration costs. Smaller diameter mains have lower

unit costs in general and medium pressure mains eliminate the need for costly road crossings and tie-ins, to establish back feeds, that are required in low pressure systems. An additional benefit to expanding the medium pressure system, is the relocation of gas meters from inside of homes and businesses to the outside, resulting in easier access for meter reading and for operation and maintenance. The Company also looks to maximize its retire to install ratio by avoiding cross country installations and installations across open areas where there are no customers.

In addition to its cost-effective design philosophy, the Company also controls costs through the use of multiple qualified contractors and competitive bidding procedures. The Company has a comprehensive contract administration program which includes standard bid conditions and procedures and includes online bidding and invoicing for efficiency. Contractor invoices submitted to Distribution for payment undergo multiple levels of review and approval to insure that quantities invoiced are proper and consistent with bid documents. The Company also performs a Post Investment Analysis on each bid project to explain project cost and quantity

variances, with a goal of reducing future variances. Finally, the Company tracks and reports unit cost trends to executive management in an Annual Unit Cost Study.

Q. Does the Company establish completion dates on projects and track schedule performance?

A. Although firm schedules may be established for certain time sensitive projects, in general, for bid projects, bid schedules and conservative completion dates are established to allow contractors latitude in scheduling awarded work. This gives qualified contractors flexibility to bid on multiple projects, keeping bid prices competitive throughout the year. The Company has found that flexible schedules result in lower unit costs. Engineering reviews the status of outstanding bid projects, with executive management, at monthly capital budget review meetings. For Company and Blanket Contractor projects, the Company generally does not establish firm completion dates on projects due to the fact that schedule priorities can change frequently based on weather conditions, emergency work, new services and customer complaints. The Company's Operations Managers maintain project schedules that are formally reviewed on a daily and

weekly basis to insure the timely completion of projects and to manage work backlogs.

Q. Does the Company have any plans to further accelerate its LPP Replacement Program?

A. Yes. In Case 15-G-0151 - Proceeding on Motion of the Commission to Consider Implementation of a Recovery Mechanism to Support the Accelerated Replacement of Infrastructure on the Natural Gas System, the Commission stated, "Our goal will be to reduce the statewide average replacement timeline to 20 years and is based on reasonable assumptions that LDCs will ramp up their removal and replacement programs". The Company's top priority is safety, and we firmly believe we are presently maintaining a safe and reliable system with our current approach to LPP replacement. However, the Company is also very interested in achieving and surpassing the Commission's stated LPP replacement goal. Beginning in 2017, the Company is proposing to further accelerate its LPP replacements beyond its already aggressive 95 mile annual replacement rate, increasing LPP replacements over the next two years to reach a 105 mile average annual replacement rate by 2018. This rate would

result in an 18 year program to replace the Company's remaining 1,897 miles of leak prone mains and 48,552 associated leak prone services, excluding large diameter mains (defined as 16" or greater in diameter) and high pressure mains (defined as operating at 125 Psig. or greater). Beginning in 2018, the Company is proposing to accelerate the replacement of its remaining 81.3 miles of large diameter and high pressure leak prone mains by an average of 5 miles annually over the following 16 years.

Q. Has the Company estimated the cost of accelerating its LPP Replacement Program.

A. Yes, the Company is forecasting an average cost of $403,750 per mile to replace leak prone mains and associated services in 2017 and $420,950 per mile in 2018, excluding large diameter mains ≥16" and high pressure mains operating at ≥125 Psig. For 2018, the Company estimates the average cost to replace approximately 4 miles of its remaining 61.8 miles of high pressure mains operating at ≥125 Psig. at $1,525,000 per mile and the cost to replace approximately 1 mile of its remaining 20.5 miles of large diameter mains ≥ 16" at $2,400,000 per mile.

Q. How did the Company determine its anticipated LPP replacement costs?

A. The Company started with its spending on pipeline replacement activities in 2015 and normalized that amount per mile of leak prone mains replaced in 2015, resulting in an average cost of $359,732 per mile of LPP reduction, including the cost of service replacements. This cost also includes the replacement of non-LPP mains and services that are replaced under the same budget activities and that are often replaced in conjunction with LPP mains and services. The Company then factored in a 15% increase[1] in pricing on 40% of its work performed under blanket pipeline contracts and applied a 5% increase to cover additional costs for ramping up pipeline replacements plus 2% annual inflation on the remaining 60% of its work performed by Company construction crews and under bid contracts. The resulting forecasted replacement costs for 2017 are 12.2% higher than actual 2015 replacement costs.

Q. Why does the Company include the cost of replacing non-LPP mains

[1] The Company competitively bid its Blanket Pipeline construction contracts for 2016-2018 with the expiration of the previous 3 year contracts bid in 2013. The Company estimates a 15% increase in overall pricing based on bid prices. Approximately 40% of the Company's pipeline construction is completed under Blanket Pipeline contracts.

and services in its average cost per mile?

A. The Company's LPP Replacement Program is imbedded in its total capital replacement budget along with replacements for system improvement and replacements due to conflicts with highway and municipal construction projects. In 2015, the Company installed 105 miles of main and retired 113 miles, including 96 miles of LPP mains, under its pipeline replacement program. It is not uncommon for projects targeting LPP replacement to have a percentage of non-LPP replacement involved on the project.

Q. Are other capital budget activities affected by the Company's Pipeline Replacement Program?

A. Yes, accelerating pipeline replacement also increases spending for right-of-way acquisition, meter purchases, and measuring and regulator station replacements.

Q. How did the Company determine the cost to replace its remaining large diameter and high pressure mains?

A. The Company estimated the replacement of high pressure mains at $34 per diameter-inch-foot and the replacement of large diameter mains at $24 per diameter-inch-foot, which is consistent with the

Company's observed replacement costs on these types of projects.

Q. Is the Company forecasting increasing costs for leak prone pipe replacement?

A. Yes. The Company anticipates and is budgeting for higher pipeline replacement costs due to continued increasing competition for contractor resources and increasing material costs as other utilities in the Northeast continue to ramp up their LPP replacements. The Company also anticipates an increase in costs due to new regulatory requirements.

Q. Can you provide some examples of new regulatory requirements that are impacting pipe replacement costs?

A. Yes. Within the past year, the Company has revised its pressure testing procedures to eliminate soap testing of short sections of pipe and tie-in sections. These segments now require a 1-hour pressure test as a result of a 2015 regulatory change to 16 NYCRR §255.507 adopted in Case 14-G-0357. In regards to Case 14-G-0212, Proceeding on Motion of the Commission to Investigate the Practices of Qualifying Persons to Perform Plastic Fusions on Natural Gas Facilities, the Company implemented new procedures to inspect

electrofusion joints, on new construction, with a second qualified individual. Also in Case 14-G-0212, the Company was ordered to document the location and inspection of all plastic fusions in an electronic database. This requires additional documentation and record keeping by construction personnel so that plastic joints and inspection information can be mapped in the Company's GIS. In addition, the U.S. Department of Transportation's Pipeline and Hazardous Material Safety Administration ("PHMSA") has pending rule changes to (1) increase inspection requirements, (2) make the installation of excess flow valves on service lines mandatory and (3) to require tracking and traceability of materials used in natural gas pipeline construction.

Q. Aside from pipeline replacement and inflation, are there any other areas of the Company's capital budget where the Company is forecasting increased spending?

A. Yes, the Company is forecasting increased spending of $1.9 Million annually for the installation of new mains and services on gas expansion pilot projects. In 2017, the Company is forecasting $6 Million for the potential acquisition of a transmission pipeline that runs

from a major interstate pipeline to a point that could interconnect with a large market area served by the Company. If the purchase occurs, it could potentially result in a system benefit that would provide a second source of gas supply to the market which is currently served from a single source. The acquisition could also potentially offset or reduce the cost of replacement of a portion of LPP transmission pipeline currently serving the market area. Also, in 2017 the Company is forecasting $2.8 Million to install 6 miles of new main to Olean, NY from a proposed new interconnect with National Fuel Gas Supply Corporation in Hinsdale, NY. The project would provide for future expansion opportunities in the Hinsdale area and it would allow the Company to abandon 8.4 miles of LPP currently serving the Olean market. In 2017 and 2018, the Company is forecasting $3.3 Million over a two year period to replace its mainframe Pipeline Facilities Inspection and Leak Management Systems with a server based software solution.

Q. Please describe the safety penalties that are currently in place as a result of the Joint Petition ("JP") adopted by the Commission in the Company's most recent rate proceeding in Case 13-G-0136.

A. The Company has penalty mechanisms in place for leak prone pipe removal, leak management, damage prevention, emergency response and gas safety violations. Failure to reach the agreed upon targets in a given year results in a negative revenue adjustment.

For leak prone pipe removal, the Company must remove a minimum of 95 miles of leak prone pipe annually or suffer an eight (8) basis point penalty. For leak management the Company is subject to a penalty for failure to maintain leak backlogs of repairable (Type 1, 2A and 2) leaks at or below 40 leaks, and total leak backlog (Type 1, 2A, 2 and 3) at or below 3,500 leaks, at calendar year end. Failure to do so would subject the Company to a four (4) basis point penalty for each metric. For damage prevention, the Company is subject to a total penalty of eighteen (18) basis points for failure to reach established targets in three areas, as follows: four (4) basis points for failure to meet 2.48 *Total Damages per 1000 Tickets*, ten (10) basis points for failure to meet 0.44 *Mismark Damages per 1000 Tickets* and (4) basis points for failure to meet 0.10 *Company and Company Contractor Damages*

per 1000 Tickets. For emergency response, the Company is subject to a total penalty of twelve (12) basis points for failure to reach established targets at three levels of response to gas leaks and odor calls; 75% within 30 minutes (6 basis points), 90% within 45 minutes (4 basis points) and 95% within 60 minutes (2 basis points). For gas safety violations, the Company is subject to a penalty of up to one-hundred (100) basis points for violation of certain gas safety regulations identified during Staff's field and records audits.

Q. Do you agree that it is reasonable to continue the penalty mechanisms that were adopted in the JP?

A. No, I do not believe that these penalty mechanisms are necessary or reasonable. Distribution has a comprehensive DIMP that manages all of the significant potential risks in its distribution system. The penalty mechanisms overemphasize improvement in only a few areas, whereas the Company's safety programs must focus on continuous improvement in all areas of pipeline safety. Furthermore, the penalty mechanisms have continued to raise the performance bar on these same metrics, over time, with no

consideration for the benefits or the cost or impact to other areas of pipeline safety, driving up the cost of compliance for diminishing returns. I would also note that a penalty mechanism only provides an incentive to reach a certain level of performance with no incentive for continuous improvement. In fact, a penalty mechanism can actually create a disincentive for improving beyond the target.

Q. Isn't it true, however, that the Company agreed to various safety criteria and penalties in the past and has, in fact, implemented such a program?

A. Yes, the Company implemented such programs solely as a result of settlements. The Company does not believe, however, that such punitive programs are either necessary nor do they enhance safety in any way. Moreover, I am advised by counsel that the Company has serious reservations as to whether such programs may be imposed absent the agreement of the Company.

Q. Do you agree with the way that penalties have been established?

A. No, I do not. The penalty thresholds represent an all or nothing approach. In the case of LPP mains, for example, replacing 94.9

miles of LPP main vs. 95 miles will bring about an eight (8) basis point penalty. One too many mismark damages will result in a ten (10) basis point penalty, regardless of the level of improvement from the previous year. In each case, compliance would be essentially achieved but significant penalties would be incurred, nevertheless. In fact, the Company would incur the same penalty as if it had not made any improvement at all. The idea that a non-hazardous leak discovered on December 31st vs. January 1st could cost the Company hundreds of thousands of dollars seems unreasonable, especially given that the leak may not even need to be repaired at all under current regulations. In addition, circumstances throughout the year may require the Company to focus its attention on more pressing system needs, but the Commission's financial penalty mechanism would provide a contradictory incentive that would have the Company improperly divert resources solely to avoid a penalty.

Setting performance targets is understandable, but any penalties should be graduated, logical and reasonable, if they are assessed at all. Another option would be to allow the Company to

make up for the shortfall in the next year before a penalty would be assessed. Of course, I do not believe that any form of penalty mechanism is warranted at all, but if the Company were to agree to such a mechanism, it would need to include an incentive, by rewarding the Company with increased earnings, for improvement beyond established targets and to permit reasonable opportunities to cure based on system requirements.

Q. Has the Company stopped improvement once it has reached a required level of performance?

A. Absolutely not. To the contrary, the Company has continually strived to improve in the area of pipeline safety and performance metrics. For example, in 2015 the Company's repairable (Type 1, 2A and 2) leak backlog at the end of the year was zero, while our penalty mechanism target stood at 40 leaks. Likewise, its total leak backlog was 2,066 while the target was 3,500. In 2015 the Company also improved well beyond established targets in the area of damage prevention with 2.20 *Total Damages per 1000 Tickets* versus a target of 2.48 and 0.23 *Mismark Damages per 1000 Tickets* versus a target of 0.44. The Company has always

been a leader in Emergency Response, significantly exceeding targets at all response levels. In the area of Leak Prone Pipe Replacement, the Company's 95 mile replacement rate is one of the highest in the state, and includes the accelerated replacement of 10 miles of, high replacement cost, cast iron mains annually, with a goal to remove these mains from our system over the next 8 years.

Q. Does the Company have any specific areas of concern with its current performance metrics?

A. Yes. The Company has an overall concern with the lack of uniformity and consistency statewide in the measurement of gas safety performance metrics.

In the area of Leak Management, over the past two years, at Staff's insistence, the Company has focused on reducing year-end repairable leak backlogs below established targets. In 2014 the Company had a year-end backlog of only one (1) repairable leak and no leaks in 2015. It should be pointed out that the leaks included in Staff's metrics do not pose an immediate safety risk and in the case of Type 3 leaks, they do not require a repair. Such

leaks are monitored within the scope of the regulations to ensure that a potential safety hazard is not present. In the Company's replacement process, unrepaired leaks not posing a potential safety risk, that are within the scope of a planned replacement project, are typically deferred for repair by replacement. The Company has pointed out to Staff that repairing such leaks in advance of pipeline replacement, to achieve lower year-end leak backlogs, is costly, redirects resources from other safety related work, and presents an inconvenience to customers.

In the area of Damage Prevention, the Company has always been concerned with being penalized for the actions of excavators that ignore long-standing state requirements applicable to excavators to avoid damaging underground facilities (see Protection of Underground facilities, 16 NYCRR Part 753). Although Staff has conceded that damages caused by excavators are not totally within the control of the Company, they contend that penalties are necessary in order for the Company to try to influence the behavior of excavators. The Company is fully compliant with the training and public advertising requirements of the One-Call

regulations. In addition, the Company works closely with contractors, especially those that have created problems in the past, to help them understand how to comply with the regulations and avoid damaging our facilities. The Company is also vigilant in recovering the cost of repairs from excavators that damage our facilities, which has a deterrent effect on recurrences. In addition, excavators who damage our facilities and did not call 811, and repeat offenders are referred to Staff for follow-up action. The Company has adopted the Common Ground Alliance Best Practices, participates in AGA Damage Prevention Best Practices Benchmarking, participates on the Board of Dig Safely NY and participates on statewide and local damage prevention committees. In this way, the Company keeps current on all trends and best practices to help improve its damage prevention program. In addition, the Company employs a full time damage prevention coordinator, who spends considerable time training contractor excavators and our line locators. The coordinator also follows up on every line hit to perform a root cause analysis in an effort to avoid recurrences. This past year, the Company implemented a

"Look Out for the Mark Out" program that rewards employees who report a homeowner or contractor who is digging without a one-call ticket. Although the Company has maintained a downward trend over the past few years in damages per ticket, the Company completely opposes any penalty that is based on the actions of others. The Company's goal is to maintain our vigilance in this area because it is in the public's and the Company's best interest to minimize excavation damage.

Finally, the Company has significant concerns with Staff's method for identifying and counting alleged violations under the Gas Safety Violations Metric. In recent field and records audit findings, Staff has cited multiple occurrences of alleged violations that prior to the adoption of this metric had been reported as a single violation. In addition, Staff has cited multiple violations and occurrences for the same alleged infraction. For example, in one instance the Company was issued four (4) separate alleged violations with eight (8) occurrences[2] for a single record. This situation involved a leak that was initially properly classified by the

[2] Staff's interpretation of the JP, which is disputed by the Company, would apply a penalty for each occurrence.

Company as a non-hazardous Type 3 leak but upon reinvestigation, the leak was not properly upgraded to a Type 2 leak based on new readings. The Company was cited for two occurrences each for both a code and procedure violation for not properly classifying the leak. The Company was also cited for two occurrences each for both a code and procedure violation for not performing surveillance based on the correct classification.

To reiterate, the Company's top priority is safety and although the Company has been critical of Staff's approach to assessing field and record audit penalties, we do believe that a collaborative approach which Staff has also pursued in discussing audit findings and corrective actions represents a best practice in ensuring the safest possible system for our customers and all stakeholders, and is more likely to yield positive results than the penalty mechanism discussed above.

Q. Do you have any other comments regarding the Company's commitment to safety?

A. Yes. James D. Ramsdell, the Company's Senior Vice President and Chief Safety Officer testified before the New York Assembly

Standing Committees on Corporations, Authorities and Commissions and Energy Subcommittee on Infrastructure, on Friday, December 4, 2015. I have included his complete testimony as Exhibit___(KDH-1), but I think Mr. Ramsdell summed it up best when he said, *National Fuel has been building and operating natural gas infrastructure for more than a century. Our highest priority is the safety of our customers, employees and the communities we serve. While we are proud of our safety record, we are also experienced enough to know that one can never become complacent. We recognize that there is always room for improvement. Our pipeline system is sizable, complex and it requires our constant attention. This is why we have worked hard to establish a culture that embraces continuous improvement in all aspects of safety.*

Q. Does this conclude your testimony?

A. Yes, at this time.

Q. Please state your name and business address.

A. My name is Kevin D. House. My business address is 6363 Main Street, Williamsville, New York 14221-5887.

Q. Are you the same Kevin House who offered testimony regarding National Fuel Gas Distribution Corporation's ("Distribution" or "the Company") Capital Budget and Leak Prone Pipe ("LPP") Replacement Program as well as testimony on the gas safety penalties imposed on the Company by New York Department of Public Service Staff ("Staff") and the New York State Public Service Commission ("Commission")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I am providing rebuttal testimony in response to testimony filed by Staff's Policy Panel, Gas Safety Panel and Gas Rates Panel.

Rebuttal to Staff Policy Panel

Q. What areas of concern do you have with the Policy Panel's testimony?

A. I have several areas of concern related to the Panel's proposals for a net plant true up penalty mechanism, additional leak reporting requirements, methane detector deployment, gathering system odorization, and plastic fusion and qualification.

1. Staff's Net Plant True up Proposal

Q. What concerns do you have with the Policy Panel's net plant true up proposal?

A. The Policy Panel states that "the Commission has established net plant true up mechanisms to protect customers from paying delivery rates that are too high because of slippage in project in-service dates or overall inflated cost estimates". Distribution does not agree that a net plant true up penalty mechanism is necessary in Distribution's case given the fact that Distribution consistently spends its capital budget as exhibited in the Company's response to UFR-83 attached as Exhibit___(KDH-2). The Gas Rates Panel recognized in their testimony regarding Distribution's historical capital spending that "without large unexpected expenditures like the increased LPP replacement target or special projects, the actual spending is close to the budget".

Q. Are there any potential negative consequences that could result from the Policy Panel's net plant true up penalty mechanism proposal?

A. Yes. In the Company's situation, where significant capital spending increases are being proposed by the Company to ramp up LPP replacements and system expansion, a net plant true up penalty mechanism is ill advised.

Unintended negative consequences can result if Staff establishes a net plant target that does not consider the time lag in converting capital spending to plant in service, and merely establishes the target based on dividing the capital budget by twelve, to establish monthly plant additions, as was done in the Company's latest rate settlement in Case 13-G-0136. In order to meet its net plant target in Case 13-G-0136, the Company had to ramp up replacements very quickly and continue bidding as unit costs escalated significantly above historical averages. The timing of the rate settlement shifted spending in fiscal 2014 to later in the fiscal year, causing the Company to actually over commit to work in order to insure that a sufficient number of projects and spending went into service by the end of the fiscal year in order to meet its net plant true up target. The Company also had to shift a portion of its capital spending to high cost, large diameter replacements since these projects tend to increase net plant totals faster than multiple smaller projects, and also to hopefully engage a different group of contractors in an attempt to stem the tide of increasing costs on traditional replacement work.

Ramping up LPP replacement spending typically results in a 6-9 month time lag before spending on capital projects is converted to plant in

service. This time lag will be considerably longer for the Company's proposed large diameter and high pressure pipeline replacement program because the planning and construction timeline for these projects is considerably longer than traditional LPP replacements. In addition, the timing of high pressure pipeline replacements is heavily dependent on state and federal agencies issuing environmental permits for construction. Any delays in obtaining project approvals will have a significant impact on monthly average net plant totals. Therefore, the Company is opposed to a net plant penalty mechanism that could force the Company to make spending decisions that may not result in the optimal use of available capital dollars, merely to meet an ill conceived net plant target, to avoid a penalty. Such a true up penalty mechanism might be an appropriate response where a company had a record of chronic under spending of its construction budget allowed in rates. That, however, as I pointed out previously, is not the case for Distribution. In our situation, the penalty mechanism is actually a deterrent to properly managing our construction budget as it results in an inefficient allocation of resources.

2. PRAs for Increased Efficiency

Q. Does the Company agree with the Staff Policy Panel's proposal to increase

efficiency and control costs?

A. Yes, in theory we do. Where an incentive proposal is properly structured and voluntary, Distribution applauds Staff's concept of rewarding innovation and efficiency through positive rate adjustments ("PRA's") for controlling unit costs and for exceeding certain targets in the areas of damage prevention and leak management. Notwithstanding the Company's currently high level of performance, Distribution welcomes the opportunity to work with Staff to develop fair and meaningful metrics that, in the appropriate circumstances, could provide an incentive (as opposed to penalties) for further improvement. However, the Company does not agree with basing PRA's on the targets proposed by the Gas Safety Panel in the areas of leak management and damage prevention. The Company's objections to the Gas Safety Panel targets will be addressed later in this testimony.

The Company also does not agree with the Policy Panel's proposal to require the Company to file an initial report within 90 days of the Commission's Order in this proceeding, which ranks all existing Type 3 leaks by the volume of methane emitted, and on an annual basis, beginning one year after that initial report, file a report detailing which leaks were actually repaired, the costs of the repairs and which technology is being used

to quantify the emissions of individual leaks. The Company objects to any new reporting requirements as unfunded mandates that unnecessarily increase costs and divert resources from performing and coordinating leak repairs and other safety related work. Furthermore, Staff's proposal for a one basis point PRA, inclusive of the cost to repair 500 additional leaks and including the proposed research, cost tracking of individual leak repairs, and reporting is unsubstantiated and unsound. The Company would require a minimum of several basis points of additional revenue to modify its accounting system to track the cost of individual leak repairs and several more basis points of additional revenue to research the available methane detection devices that might be suitable to quantify methane emissions, purchase the equipment and survey leaks on an ongoing basis to determine the level of methane emissions from each leak, plus submit an annual report to Staff detailing all of this information - all of this before a single leak is repaired. It would seem a better use of this money to simply repair more leaks.

3. Residential Methane Detectors

Q. The Policy Panel is proposing an incentive for Distribution to encourage the advancement of residential methane detectors by requiring Distribution to

develop a proposal in consultation with Staff to deploy residential methane detectors within its service territory. Does Distribution have any concerns with the Policy Panel's proposal?

A. The Company has several concerns with the Policy Panel proposal. The Company does not believe that installing methane detectors in urban housing developments, multi-family residences and apartment buildings is the responsibility of a gas utility. Similar to existing requirements for the installation of smoke alarms required by the Residential Code of New York State, the Property Maintenance Code of New York State and the Fire Code of New York State, this responsibility should reside with the property owner. The responsibility for continued maintenance and replacement and the liability for equipment misuse or failure should also not be the responsibility of a gas utility. Gas utilities are responsible for the operation and maintenance of gas piping, including periodic leak surveys, to the outlet of the customer meter, the connection to a customer's piping, or the outside of the building foundation wall, whichever is further downstream. The Company's obligations beyond that point are generally limited to those duties set forth in 16 NYCRR Part 261, Piping Beyond the Meter, none of which remotely address the concept of utilities installing,

owning, operating or maintaining residential methane detectors. The Company cannot agree to a Policy Panel proposal that could potentially result in expanding the Company's responsibilities to include monitoring for leakage on customer owned piping beyond the limited requirements of Part 261.

The Policy Panel proposal would also have the Company consider the installation of methane detectors to monitor Company owned indoor natural gas facilities between the building wall and the meter. It should be pointed out that the Company takes the issue of leaks on customer-owned facilities and gas appliances seriously as demonstrated by its effective Warning Tag procedures implemented in accordance with 16 NYCRR 261.51 and already has programs in place to mitigate the risk of leaks from Company owned indoor piping. Over 78% of Distribution's meters are located outside of buildings and the Company has a policy to relocate existing inside meters outside at the time of service renewal. In addition, Company meter readers wear personal methane detectors to monitor for leaks around Company piping when reading meters.

According to the Policy Panel's testimony residential methane detectors are commercially available, however, new technologies for

detecting methane are being researched and tested to improve the overall effectiveness of detectors and to eliminate a common problem of false positives, or alarms in reaction to common household chemicals, The Panel also states that methane detectors on the market today alarm at methane levels much higher than the human nose detects, and the newer technology being developed will alarm at lower levels.

Based on the fact that the new methane detector technology is not available yet it would seem premature to develop implementation plans until the technology has been proven under real world conditions. A large-scale implementation of an unproven new technology could be costly and may do more harm than good if problems, like those encountered with first generation detectors, start to occur down the road. The Company recommends that this initiative be reevaluated in the future, preferably on a statewide basis and not in an individual company's rate proceeding.

4. Gas Gathering Line Odorization

Q. In order to encourage the Company to assist in Staff's gas safety efforts to odorize any gas gathering line within 150 feet of a residence or operating at 125 pounds per square inch or higher, the Staff Gas Policy and Supply Panel

recommends providing the Company with an incentive for ensuring that gathering systems directly connected to the distribution system meet the appropriate standard for odorized gas. What are the Company's concerns with such an incentive?

A. First of all, the authority and responsibility for enforcement of regulatory requirements for odorization in gathering systems lies with the New York Department of Public Service Office of Electric, Gas and Water, and not with the downstream gas utilities. Second, Staff spends a significant amount of time auditing the Company's records and field operations, including auditing odorization records, in order to identify areas of non-compliance. Distribution respectfully submits that Staff should audit local producers in a similar fashion and implement penalty mechanisms or incentives for local producers to comply with regulatory requirements.

The Gas Policy and Supply Panel proposes that: the Company should file a survey of the gathering lines for all 971 meter connections identified previously with the Secretary to the Commission within 60 days of the order in this case. This survey should include the responsible entity for each meter, the status of the annual production through each meter, and the status of compliance with the rules and regulations regarding odorization of gas. The

Company should also recommend a possible incentive for itself to implement this effort for odorized gas at the same time it ensures that the production facilities can remain on the distribution system, eliminating the possible threat of shutting in wells. Based on Distribution's experience in odorizing its own gathering system, this is a significant undertaking that would require a major commitment in time, money and resources to complete such a survey. The Company would most likely need to locate, survey and map producer gathering lines in order to determine areas requiring odorization, within 150' of a residence and on lines operating above 124 Psig. The Company would then need to perform periodic inspections to monitor the producers' systems for proper odorant levels. The Company could not simply monitor odorant levels at interconnections with Distribution since this would not guarantee that all of the areas requiring odorization on the producer's system are properly odorized. This effort would require Distribution to hire additional personnel to monitor and oversee such a program. It is the Company's belief that the responsibility for enforcing pipeline safety regulations is best left with regulators and should not be delegated to gas utilities. In addition, as explained in greater detail in the Rebuttal Testimony of the Company's Gas Supply Administration Panel,

Staff's proposal raises numerous issues regarding the legal ability of the Company to enter private property to inspect third party facilities without the landowner's or the producer's permission.

5. Plastic Fusion Penalty

Q. Earlier in this testimony you stated that you had concerns with the Policy Panel's proposal related to plastic fusion and qualification. What are your concerns?

A. The Panel proposes a penalty of $1,680,000 arising out of Case 14-G-0212 that I believe is unwarranted for a number of reasons. First, I have some concerns with the factual accuracy of the Policy Panel testimony, particularly its effort to tie a completely unrelated event in our Pennsylvania territory in 2004 with the circumstances in Case 14-G-0212. At page 39 of the Policy Panel testimony related to an incident that occurred on the Company's system in Dubois, Pennsylvania in 2004, the Panel states that "Investigators determined that the electrically fused joint was poorly aligned, which indicated workmanship concerns for Distribution." The Company disputed Staff's claims which Staff has since corrected in their responses to Information Requests NFG-DPS-176 and NFG-DPS-177 attached as Exhibits___(KDH-3) and Exhibit___(KDH-4). For the record, the fusion in

question was a 2" plastic butt fusion joint and investigators never indicated a workmanship issue for Distribution. Furthermore, the Company never agreed with the National Transportation Safety Board's ("NTSB") finding of probable cause in the incident and contends that the probable cause was a third-party excavation that undermined and placed an undue bending stress on a butt fusion joint causing a failure in the pipe adjacent to the butt fusion joint. See attached Exhibit___(KDH-5) and Exhibit___(KDH-6). Moreover, Staff's attempt to tie the two incidents is entirely misplaced. The issue in Case 14-G-0212 arose because there was an apparent lapse in the Company's fusion qualification program that omitted destructive testing of specimen joints between 2011 and 2014. The Dubois, PA incident occurred in 2004 and the NTSB neither identified training lapses nor even mentioned destructive testing. Furthermore, the 2004 incident occurred well before the training lapse apparently began in 2011. The incidents simply are not even remotely connected. Nor, as I mentioned, does the Company believe the NTSB report is accurate.

Q. Do you agree with the Policy Panel's proposed penalty of $1,680,000?

A. No. The Panel is proposing a penalty based on their assertion that Distribution's customers were put in added safety risk because the Company

was out of compliance with its training procedures. The Company contends that the Panel's claim in this regard is totally unfounded and not supported by the facts. In fact, Distribution took prompt action to eliminate any potential risk that may have resulted from the lapse in its qualification program, as follows:

1.) In response to the Commission Order in Case 14-G-0212, issued on June 27, 2014, Distribution promptly performed an evaluation of its plastic fusion qualification program and discovered a lapse that omitted destructive testing of specimen fusions. Upon discovering the lapse, Distribution immediately notified Staff, on June 30, 2014, that it had stopped work on all plastic fusions and that it was commencing an effort to requalify its employees and contractors with destructive testing. The Company would point out that its employees have always been trained and qualified on an annual basis to perform plastic fusions, including during the time when destructive testing was omitted from the Company's program.

2.) Due to the fact that the Company maintained detailed records on the location and joiner of plastic fusions in its system, a practice that it began in 2006 following the Dubois incident, the Company was able to

identify the location of plastic fusions that were performed by individuals who were not properly qualified or who failed a requalification test.

3.) Distribution filed a comprehensive remediation plan and completed a risk assessment as required in Case 14-G-0212. The Gas Safety Panel in their testimony stated that "Distribution's risk assessment plan consisted of targeted fusion inspections, random fusion inspections, normal course of business fusion inspections, destructive testing of fusions, and quarterly leak surveys." The Gas Safety Panel also stated that "Distribution inspected 644 fusions and performed 129 destructive tests, all of which passed. Leak surveys of over 763 miles were conducted to address the risk from the period of noncompliance." When asked to describe Distribution's performance in addressing the noncompliance, the Gas Safety Panel stated "Distribution took immediate action to address the noncompliance, fully assessed the risk posed by the noncompliance, took timely actions to mitigate possible risk during its assessment, and promptly eliminated or remediated every noncompliant plastic fusion found. To highlight Distribution's commitment to addressing the noncompliance, we note that 316 inspections and 83 destructive tests of the inspections and tests performed were a result of Distribution following up on the results of one

targeted fusion inspection".

4.) The Gas Safety Panel estimated that 31,500 fusions were performed by under-qualified persons during the period 2011 through 2014. A review of Company leak records, however, cannot find any reports of leaking fusions that were installed during this period.

5.) The Company has had in place since 2006 a program for the inspection of butt fusions by a second qualified individual and a comprehensive plastic fusion inspection and remediation program that requires a remediation plan for any projects where a visually questionable or leaking fusion is discovered during normal operation and maintenance activities.

6.) Since discovering the lapse in its fusion qualification procedures the Company has not only corrected the lapse but has significantly improved its plastic fusion training and qualification program and its plastic fusion joining and inspection procedures.

Distribution has fully cooperated with Staff in complying with the Commission Orders in Case 14-G-0212 and has demonstrated through inspections and remediation that its customers are not at risk as a result of a lapse in its qualification procedures that omitted destructive testing for a

period of time. Based on the facts, the Policy Panel's proposed penalty is unwarranted.

Q. Do you have any other concerns with the Staff Policy Panel proposed penalty of $1,680,000?

A. Yes. Aside from the fact that the penalty is unwarranted, the Company does not agree with Policy Panel calculation of its proposed penalty. The Panel based their penalty on the penalty mechanism in the Company's Gas Safety Violation Metric established in the joint proposal in Case 13-G-0136, for a violation of 16 NYCRR §255.603(d). The Panel calculated their proposed penalty by applying a 1/2 basis point penalty ($28,000) capped at a maximum of 15 occurrences per year, over the four year period 2011-2014 when destructive testing was omitted from the Company's qualification program ($28,000 x 15 x 4 = $1,680,000). See the Policy Panel response to Information Request NFG-DPS-178 attached as Exhibit___(KDH-7).

As stated previously, the Company does not agree to the Policy Panel proposed penalty, however, the Company would point out that a penalty under the Company's Gas Safety Violation Metric established in the Joint Proposal in Case 13-G-0136 can only be applied beginning in 2014 when the Company, also, in fact, corrected the lapse in its qualification program.

Therefore there should be no penalty under this mechanism. There is certainly no arguable basis for a penalty in 2011-2013 because the penalty for regulatory non-compliance was not in effect in those years.[1] Furthermore, if a penalty can be assessed for a procedural violation under 16 NYCRR §255.603(d), in 2014, then there would only be one occurrence of a violation resulting in a 1/2 basis point penalty.

Q. Are there any other penalties that have been proposed by Staff as a result of Case14-G-0212?

A. Yes, the Gas Safety Panel has proposed that the Company be prohibited from recovering any costs associated with Case 14-G-0212 from ratepayers and that any such costs be normalized out of the historical period.

Q. Does the Company agree with the Gas Safety Panel proposal?

A. The Company agrees that its ratepayers should not bear the cost for the Company to identify and correct any deficiencies arising out of its lapse in destructive testing. The Company supports the Gas Safety Panel position that the remediation costs be absorbed by Distribution in the interest of fairness to our customers. We do not agree, however, that it is appropriate

[1] The Commission Order in Case 07-G-0141 directed the Company to comply with the Safety Metrics recommended by Staff. Those metrics did not include a regulatory compliance metric. The metrics were replaced by those adopted in the JP in Case 13-G-0136, which were effective only for years commencing in 2014.

for the Company to be double penalized as proposed by the Policy Panel, with both the remediation costs having to be absorbed by the Company and an additional penalty being imposed on top of that.

Q. Do you have any additional concerns with the Policy Panel's testimony?

A. Not at this time.

Rebuttal to Staff Gas Safety Panel

Q. What are your comments or areas of concern with respect to the Staff Gas Safety Panel testimony?

A. I have several comments and concerns related to the Gas Safety Panel's proposals in the areas of Infrastructure Enhancement, Leak Management, Damage Prevention, Emergency Response, Non-Compliance with Pipeline Safety Regulations, Integrity Management, Inactive Accounts and Annual Reporting.

1. Infrastructure Enhancement

Q. What are the Company's comments and concerns with the Gas Safety Panel's proposals for Infrastructure Enhancement?

A. First of all, I would like to comment on a statement in the Gas Safety Panel testimony on page 12, which states that " Typically, the Company only proactively removes and replaces pipe, beyond the requirements of the

pipeline safety regulations found in 16 NYCRR Part 255, because of significant customer complaints, or as a result of municipal or state construction projects." This statement is incorrect and does not accurately portray the Company's aggressive and long standing pipeline replacement program. The Company's "Systematic Replacement" program began in 1997 and has resulted in the replacement of approximately 1,795 miles or 47.6% of the Company's leak prone bare steel, cast iron and wrought iron mains and approximately 87,030 or 64.2%, of the Company's bare steel services, since that time. The Company's "Systematic Replacement" program is described in detail in the Company's response to Utility Filing Requirement ("UFR") Question 84, Attachment C, attached as Exhibit___(KDH-8).

Q. In its rate request, Distribution is proposing to ramp up its already aggressive LPP replacement program to 100 miles in 2017 and 110 miles in 2018, including 5 miles of large diameter and high pressure LPP replacement. Has the Gas Safety Panel proposed any penalties if Distribution fails to meet these targets?

A. Yes, the Panel has proposed an annual penalty of 8 basis points if Distribution fails to meet its LPP replacement targets. In 2017, Distribution

would be subject to an 8 basis point penalty for failure to replace 100 miles of LPP. Each year thereafter Distribution would be subject to a 6 basis point penalty for failure to replace 105 miles of LPP and a 2 basis point penalty for failure to replace 5 miles of larger diameter and high pressure LPP pipe. The Panel is also recommending that the Commission should require the Company to replace leak prone services in conjunction with the associated mains. As the Company replaces the mains and services, it should also be required to install meters in a readily accessible location, preferably located outside and protected from corrosion and other damage.

Q. Does Distribution agree with the Gas Safety Panel's proposal for an LPP replacement penalty mechanism?

A. No, Distribution is opposed to any such penalty mechanism and we are certainly opposed to a penalty mechanism with an "all or nothing" approach as proposed by Staff. Under Staff's proposal, Distribution would have to pay the same 8 basis point penalty for failing to meet its LPP replacement target by 1/2 mile as by 20 miles. Staffs proposal has no gradation of the penalty amount and no flexibility to allow the Company to make up a mileage shortfall in the following year. The problem with a penalty mechanism of this nature is that it may have unintended consequences of creating an

incentive for the Company to make decisions that may not be in the best interest of the rate payers, such as potentially overpaying for pipe replacements in order to avoid a penalty. A penalty mechanism should never be so severe, or structured in a way that it could force an individual to prioritize work with the knowledge that selecting one project over another could result in a penalty for the Company. Distribution has consistently met or exceeded its LPP replacement targets in the past and therefore a penalty mechanism is unwarranted. The Company has committed to ramping up its LPP replacement program and we believe that we can do it in a way that will improve safety and reliability in a cost effective manner, however, introducing a penalty mechanism will bring other factors into the decision making process.

Q. Do you have any concerns with the Gas Safety Panel's proposals for replacing service lines and relocating meters outside?

A. No. The Company has been diligently upgrading services and relocating meters outside in conjunction with main replacements for many years without a Commission order.

Q. Does the Company have any concerns with the new reporting requirements proposed by the Gas Safety Panel related to LPP replacements?

A. Yes. The Panel is recommending that Distribution submit a quarterly report to the Secretary of the Commission detailing its leak prone pipe replacement progress. The recommendation requires that the report should include material type, mileage, project location, rank of the segment replaced at the time of replacement using the risk based model, project cost, and include a forecast of the scheduled leak prone pipe replacement projects and their rank on risk based replacement model for the upcoming quarter, at a minimum. Staff further recommends that the report should also be required to include a reconciliation of proposed replacements versus what was actually replaced and that the Company should be required to submit these quarterly reports no later than thirty days after the end of the quarterly reporting periods ending March 31st, June 30th, September 30th, and December 31st.

These added reporting requirements are burdensome and wholly unwarranted. First of all, the Company does not currently have a computer system that is capable of supporting this added reporting requirement. To create this report will either require a new system designed to pull this information from various other reporting systems and manual reports, or the Company will need to add staff to manually maintain the data and create the reports. A new system will need to be flexible to accommodate the changing

nature of reporting requirements in each new rate case or rate settlement. Second, in the absence of standardized reporting for all New York utilities, the Company does not believe that Staff or the Company will use these reports in any meaningful way other than to check the box that we have completed a mandated requirement each quarter. The Company has been able to maintain its LPP replacement program, meeting replacement targets, and reducing leak rates and outstanding leaks, using our existing systems and internal reports. We already submit semi-annual reports to Staff on the status of our LPP replacements, as required under the joint proposal in Case 13-G-0136. Therefore, we do not believe that this significant new reporting requirement is warranted or cost effective.

2. Leak Management

Q. What are the Company's comments and concerns with the Gas Safety Panel’s proposals for Leak Management?

A. The Company does not agree with the total leak backlog target established by the Gas Safety Panel. Over the past four years Distribution has been able to reduce its total year end leak backlog by nearly 55% to a total of 2,066 leaks at year end 2015, based on the year-end Statewide Performance Measure report to Staff, exceeding the Company's latest rate settlement

target of 3,500 leaks by a considerable margin. These reductions have been achieved through our continued commitment to the Company's LPP replacement program and a considerable allocation in Company employee resources and O&M spending on leak repairs. The Gas Safety Panel is now proposing a NRA if the Company does not achieve another 22% reduction to 1,600 total leaks in 2017, essentially penalizing the Company for its good past performance. The overly aggressive target proposed by the Panel, which is based on the Company's excellent past performance, now puts the Company at risk for a Panel proposed 4 basis point penalty. Distribution would have been better off, from a potential penalty standpoint, stopping leak repairs when it reached its previously established rate case backlog target of 3,500 leaks. This point highlights why penalty mechanisms establish a disincentive for significantly exceeding targets in the future.

Q. If Staff prevails in establishing a penalty mechanism, how would Distribution reach Staff's proposed target?

A. This is a good question. The Staff Policy Panel is under the impression that Distribution can achieve this 22% reduction in total leak backlog in 2017 as a result of its modest 5% increase in LPP replacements and, therefore, Staff has not allowed any additional funding for this initiative. Staff's position is

highlighted in their response to Information Request NFG-DPS-170, attached as Exhibit___(KDH-9). Contrary to Staff's opinion, the Company can only achieve a limited number of leak repairs and leak reductions through its LPP replacement program. In 2015 the Company only repaired 1,027 leaks or 23% of its total leak repairs through LPP pipeline replacement or abandonment. All things being equal, the Company's proposed increase in LPP replacements may possibly result in an estimated reduction of 54 leaks. The remaining reduction of 412 leaks will need to come at the expense of reducing other safety related work or through additional funding – funding that has not been recognized by Staff.

Q. Does the Company have any other concerns with the Gas Safety Panel's leak backlog penalty mechanism or targets?

A. Yes. The Panel has proposed an 8 basis point penalty if the Company fails to meet a repairable leak backlog of 25 leaks at year-end. Distribution is proud of the fact that we were able to reduce our year-end repairable leak backlog in 2014 to one leak and in 2015 to zero leaks. Distribution plans to continue to strive for a zero year-end repairable leak backlog, however, we recognize that there may be circumstances beyond the Company's control such as an early frost at the end of the year or a natural disaster such as

flooding or an earthquake, that could result in a significant number of new leaks, that could prevent the Company from reaching the Panel proposed target. In the past, Staff has said that they would make allowances for a significant event, however, there is nothing guaranteeing that in the Panel's proposal and therefore the Company cannot agree to the Panel's proposed penalty mechanism. Another area of concern for the Company is that there is no penalty gradation in the Panel's proposal. The Company would be subject to the full 4 or 8 basis point penalty by missing the proposed targets by one leak or by 100 leaks, thus evidencing a lack of proportionality.

In light of the inherent problems with a leak backlog penalty mechanism discussed above, the Company would encourage Staff to eliminate their proposed NRA for leak backlog in favor of a PRA as proposed by the Policy Panel although beginning with a more reasonable total leak backlog target of 1,800 leaks for a PRA.

3. Damage Prevention

Q. What are the Company's comments and concerns with the Gas Safety Panel’s proposals for Damage Prevention?

A. The Gas Safety Panel is recommending that Distribution be required to maintain the 2015 statewide averages of 0.42 for damages due to

mismarks, 0.09 for damages due to Company and Company contractors, and 1.87 in total. In the area of total damages the Panel is recommending that a three year approach be implemented to allow the Company to progressively work towards the 1.87 level. The targets for total damages proposed by the Panel are shown in the following table along with Distribution's most recent performance for comparison.

Damage Prevention Metric	Actual Company Results Damages/1000 Tickets			Panel Proposed Targets Damages/1000 Tickets		
	2015	2016 YTD Old Guidelines	2016 YTD New Guidelines	2017	2018	2019
Mismarks	.23	.18	.18	.42	.42	.42
Company	.02	.01	.01	.09	.09	.09
Total	2.20	**2.01**	**2.50**	2.17	2.02	1.87

The Panel has also proposed that Distribution's reporting of Company performance on these measures be in compliance with the most recent Gas Safety guidance letter dated December 11, 2015, issued by the Deputy Director of the Office of Electric, Gas, and Water.

Q. Does Distribution have any concerns with the targets established by the Gas Safety Panel?

A. Aside from the fact that I am advised by counsel that imposition of such penalty mechanisms are beyond the Commission's power, in practical

terms, Distribution does not have any concerns with the targets proposed by the Panel for mismark damages and Company and Company contractor damages because the Company already meets or exceeds the performance targets proposed by the Panel and these metrics are unchanged by Staff Gas Safety reporting guidance issued December 11, 2015.[2] Distribution does not agree with the targets established for total damages since this metric has been significantly changed by Staff's new reporting guidance. Reporting guidance that was previously in place for 2015 Performance Measure reporting excluded hand digging damages and homeowner damages, when there was no locate request. These damages are now included under the new reporting guidance. The impact of this change is significant as highlighted by the difference in the Company's 2016 YTD total damage performance using both the new and old reporting guidance (2.50 vs. 2.01) as shown in red in the table above. The new reporting guidance results in the Company including 30 additional damages YTD (168 vs. 135) in calculating its performance. Based on the new reporting guidance it is improper for the Gas Safety Panel to establish targets for the

[2] I am also advised by counsel, however, that the Company rejects the notion that compliance standards can lawfully be established in guidance documents, rather than in notice and comment rulemaking proceedings in keeping with the State Administrative Procedure Act.

Company based on the 2015 statewide average performance which was reported using old reporting guidance and which would now be higher simply based on the reporting differences.

Q. Does the Company have any concerns with the damage prevention penalties proposed by the Gas Safety Panel?

A. Yes. The Panel is recommending that Distribution be subject to a negative revenue adjustment totaling18 basis points should the Company fail to achieve the recommended damage prevention targets. Specifically, the Panel is recommending penalties of 7 basis points for damages due to mismarks, 7 for damages due to Company and Company contractors, and 4 for total damages.

Consistent with the Company's previous testimony, Distribution is opposed to any penalties associated with gas safety performance measures for the same reasons as outlined previously. In addition, damages caused by excavator error and no call damages are not within the Company's control and the Company's ability to influence excavators is limited. Therefore a penalty associated with total damages is completely unwarranted. With that said, Distribution is not opposed to Staff setting goals and expectations for Company performance that are reinforced with

PRA's as proposed by the Staff Policy Panel which is recommending a new positive incentive of 4 basis points should the Company be able to maintain fewer than 1.50 damages per 1,000 one-call tickets in a given calendar year.

Q. Do you agree with the Gas Policy Panel target for earning the proposed PRA?

A. No, the Panel's target is too aggressive to be meaningful, especially given the impact of new reporting guidance on total damage performance levels. Based on the new guidance, Distribution would recommend a target starting at 2.40 for a PRA of 1 basis point, 2.30 for 2 basis points, 2.20 for 3 basis points and 2.10 for 4 basis points.

Q. Do you have any other comments in the area of damage prevention?

A. Yes. The Gas Safety Panel stated in their testimony that the Company can minimize damages caused by no-calls and excavator error by influencing excavator activity through education and outreach efforts to excavators, by continuing to bill excavators for repair costs when the excavator is at fault, and by referring problem contractors to Department Staff for enforcement purposes. In addition, the Panel contends that Distribution should consider

developing best practices, in conjunction with other companies affiliated with the Northeast Gas Association and/or other trade associations.

Based on Panel's testimony, someone could conclude that the Company does not already take these steps to minimize damages. In fact the Company takes all of these steps and more as highlighted in the Company's response to Staff's Annual Performance Measure Report to the Commission, that is attached as Exhibit___(KDH-10).

4. Emergency Response

Q. What are the Company's comments and concerns with the Gas Safety Panel proposals for Emergency Response?

A. Distribution is opposed to any penalties associated with the Company's failure to meet the Panel proposed emergency response targets. Distribution has been a leader in statewide performance in emergency response for many years. The Company continually evaluates its performance and makes adjustments as needed to ensure that we respond to all emergency calls in the shortest time possible. We adjust staffing levels on various shifts to better respond to emergency calls and we work to remove any and all impediments that could potentially slow down a first responder. It is the Company's firm belief that the most hazardous condition is the unknown condition, so we

strive to respond to any emergency situation in the least amount of time. Despite the Company's excellent performance in this area, we recognize that there may be circumstances beyond the Company's control, such as a natural disaster or severe weather event, that could prevent the Company from meeting the Panel's proposed targets. In the past Staff has said that they would make allowances for a significant event, however, there is nothing guaranteeing that in the Panel proposal and therefore the Company cannot agree to the Panel's proposed penalty mechanism. Regardless, the Company will continue to strive for a high level of performance in this area, as the Company strongly believes that a rapid emergency response coupled with a thorough investigation is essential to operating a safe system.

5. Non-Compliance With Pipeline Safety Regulations

Q. What are the Company's comments and concerns with the Gas Safety Panel proposals for Non-Compliance With Pipeline Safety Regulations?

A. The Company has several comments and concerns in this area, however, I will begin by affirming that Distribution's first priority is to ensure the safety of our customers and the communities we serve. To that end, we support a comprehensive approach to gas safety, as reinforced by the field and records audits conducted by Staff. The Company takes Staff's findings in such

audits very seriously, and we immediately implement corrective action to rectify any instances of non-compliance and to prevent a reoccurrence in the future. Staff's findings are also used to enhance our training and quality assurance programs.

In their testimony, the Panel states that they do not find Distribution's compliance performance acceptable and that "any number of violations can indicate a lack of the Company control, an issue with internal quality assurance, or a Company culture that is willing to accept a level of non-compliance with the regulations". The Company assures the Panel that the Company suffers no "lack of control," maintains a vigorous program for quality assurance, and has a proactive culture of safety compliance that begins at the top and is integral to the Company's operations, planning and resource deployment. Distribution categorically denies any such assertion that the Company has a culture willing to accept non-compliances. To the contrary, the Company's culture is one that is not willing to accept any level of non-compliance.

The Company has taken many proactive steps to reduce the possibility of violations such as beginning an initiative to replace its mainframe based Pipeline Facilities Inspection system and hardcopy

inspection records with a new system that will accommodate electronic field data collection that should significantly help reduce human error. In the meantime, the Company has established many new manual reviews to act as safety nets to catch and correct any human errors that could negatively affect our compliance. While these reviews require additional resources to complete, the fact that we are performing them now exemplifies Distribution's commitment to safety and compliance.

Q. In their testimony, the Panel states that "on average, from 2010 through 2014, Staff has cited Distribution for 36.6 high risk and 8.4 other risk violations of the minimum pipeline safety regulations". Does the Company agree with the number of violations cited by the Panel?

A. No, we do not. The Company questioned the Panel on the development of the number of violations to which the Panel affirmed in their response to Information Request NFG-DPS-130, attached as Exhibit___(KDH-11), that "The data as reported within Appendices G, and H of the 2015 Gas Safety Performance Measures Report, Case 16-G-0254, were extrapolated from the record and field audit compliance letters". At the conclusion of each audit, Staff issues record and field audit compliance letters to which the Company is given 30 days to respond outlining any actions the

Company will take or has taken to prevent similar violations from occurring in the future. The Company's responses to Staff's compliance letters during the period 2010 through 2014 disputed many of Staff's alleged violations, however, there is no evidence that Staff considered the Company's objections in the number of reported violations in the 2015 Gas Safety Performance Measures Report. Therefore the number of violations reported by Staff in the 2015 Gas Safety Performance Measures Report and in their testimony are actually only alleged violations that have not considered the Company's objections and that have not been subject to any formal dispute process other than a post-audit compliance meeting with local Staff.

Q. What are some of the reasons that the Company has for disputing violations identified by Staff?

A. Each alleged violation has its own set of unique circumstances that need to be evaluated to determine if the Company's actions violated a regulatory requirement. Many regulatory requirements are general in nature and therefore they require the Company to develop specific procedures to meet the intent or meaning of the regulation. The majority of the reasons for disputes can be categorized in a few primary areas.

1.) Over-counting: Staff often times will cite several violations stemming from a single infraction. One example of this would be a situation where a Company gas mechanic reinvestigates a leak and when sampling the area for gas readings the gas mechanic fails to recognize that the new readings require an upgrade to the leak classification to a higher grade. This would result in a violation, if discovered by Staff during a records audit. In this situation, however, Staff will typically document several violations since an upgraded leak would then be subject to more frequent surveillance and a shorter mandated time frame for repair. In the case of leak management, the Company has procedures that have the same requirements for classification, surveillance and repair, as the regulatory language in 16 NYCRR Part 255. Therefore the Company may also be cited for procedure violations for classification, surveillance and repair, resulting in a minimum of six violations for a single infraction. If more than one surveillance frequency would have been missed at the higher classification, or if the higher graded leak required a recheck after repair, then there could be eight or more alleged violations stemming from a single infraction. In many cases, an infraction of a regulation results in two violations, one for the regulation and one for a violation of a Company procedure that implements that regulation.

2.) Interpretation: As mentioned before, many regulatory requirements are general in nature and therefore subject to interpretation as to whether or not the Company's actions met the intent of the regulatory requirement.

3.) Incorrect or Missing Documentation: Almost every action taken by the Company requires documentation. During the course of an audit, Staff may discover a record that is missing information or that has incorrect information. Disputes in this area generally arise when Company personnel have taken the appropriate action for compliance, but did not document the action correctly or completely.

4.) Interpretation of Company Procedures: Disputes will sometimes occur when Staff inspectors have a different interpretation of a Company procedure than the Company does. These situations are especially frustrating for the Company when the Company's procedures exceed the regulatory requirement. These types of violations can create a disincentive for the Company to adopt procedures that go beyond regulatory requirements even though they may result in a greater margin of safety.

Q. Does the Company have any concerns with Staff's consistency in conducting audits or determining violations?

A. Yes. The Company has concerns with the consistency of the audit process from year to year, and also, now that Staff is reporting audit statistics in their Annual Gas Performance Measures Report, we are concerned with the consistency of audits from company to company since comparisons will certainly be made in the future.

Regarding the consistency of Staff's audits from year to year, in the Panel's testimony, at page 40, the Panel states "*Historically* [emphasis added], audit letters outlined findings that note a violation of a specific requirement, and then associated it with the total number of occurrences found. The term violation is commonly referred to in discussions and is widely understood within the pipeline industry. Thus, for the purpose of this non-compliance measure, there is no difference between a violation and an occurrence. These words are and can be used interchangeably. Staff considers both terms as an instance of non-compliance with the Commission's pipeline safety regulations". The Company is concerned that Staff has adopted the use of the term "occurrences" in a fashion that increases the total number of violations cited that are subject to an NRA. The Company has raised its concern with Staff on several occasions, including in letters dated February 14, 2014 and November 20, 2015. To

reiterate the Company's position shared with Staff, Distribution entered into the Joint Proposal in Case 13-G-0136, the terms of which were adopted in the Commission's Order dated May 8, 2014, with the understanding – and reasonable expectation – that future audits would be conducted using the same terms, interpretations and practices of prior Staff audits. The Company believes Staff's current approach to be different from Staff's historical approach, which was also the approach relied on when Distribution entered into the Gas Safety Violations Metric in the Joint Proposal.

With regard to the consistency of audits from utility to utility, Appendices G and H of the 2015 Gas Safety Performance Measures Report, (the relevant pages of which are attached as Exhibit__(KDH-12)), compare the number of violations for the major NY utilities along with the number of Operating Headquarters ("OHQ"). The number of OHQ's vary by company, but they do not appear to be proportionate with the size or complexity of their systems. Figure #12, in the same report, shows a graphical representation of historical violations by utility normalized by the number of OHQ's for each utility, a metric where the Company clearly has the lowest non-compliance rate in the state. In Information Request NFG-DPS-134, attached as Exhibit___(KDH-13), the Panel states that,

"Staff conducts record and field audits annually for each operating headquarter found within an LDC. The sampling of records is determined by the specific regulations to be audited in a given calendar year, the population size within each operating headquarter of the regulations to be audited. Sample sizes are selected so that the audit results have a 95% confidence level with a 15% confidence interval." Given Staff's response, it appears that companies with more OHQ's would have a larger number of records sampled and therefore potentially a larger number of alleged violations identified by Staff. This methodology of sampling clearly discriminates against companies with more OHQ's.

Finally, the Company is not aware that Staff has procedures for conducting their audits in order to insure consistency from office to office and among inspectors in the same office. To be valid, a statistical sample should audit a random sample of records. The Company understands that Staff can audit the Company's records as they deem necessary to insure safety, however, to insure consistency in applying penalties under a performance measure, Staff should follow a strict set of rules when conducting their audits by selecting their sample in advance from a list of

available records, and selecting only the number of records required for a 95% confidence level with a 15% confidence interval.

Q. Does the Company have any comments or concerns with how Staff has assigned risk to the various code sections for the purpose of assessing penalties?

A. Yes. The Company believes that Staff's methodology for designating "high risk" and "other risk" code sections is too simplistic and does not accurately assess risk. It does not make sense that missing an annual valve inspection by one day is deemed a “high risk” violation. For instance, was the system really any safer if the valve had been inspected the day before? How is completing a follow-up inspection after repair of a type 2 leak 13 days after repair vs. the code required14 days a high risk violation? If there were no readings on day 13 then it is highly unlikely that there will be readings on day 14. If there are readings on day 13, then a new leak report would be filled out, arguably actually making the system safer than if visited on day 14. Staff should reconsider their methodology for assessing the risk of a violation and consider assigning risk on a case by case basis relative to the circumstances. As it is, save for Staff’s claim that the risk designations were devised by Staff’s “subject matter experts” who were trained in PHMSA

procedures, there is simply no way to ascertain how risk was assigned to a particular violation of a code section. Moreover, the regulations in Part 255 are not denoted for risk and I am unaware of any such designation by PHMSA.

Q. Based on Distribution's experience with Staff's non-compliance penalty mechanism in the Company's current rate settlement in Case 13-G-0136 does the Company believe that the Gas Safety Panel's proposed non-compliance penalty mechanism is in the best interest of its customers.

A. The Company is in full support of the Panel's goal to reduce non-compliance with gas safety regulations. We also applaud the Panel's proposal to reinvest any penalties back into pipeline safety initiatives. However, Staff's non-compliance penalty mechanism is overly punitive given Staff's practice of counting multiple violations for a single action, compounded by intimidating penalty levels that are disproportionate to the risk. We do not believe that it is in the best interest of our customers when the Company is hesitant to write a procedure that exceeds code requirements because it could then be used against us to assess a significant penalty in an audit. The Company is strongly opposed to Staff's practice of citing the Company for both a code violation and a procedure violation when the procedure is written to comply

with the code.

The Company would urge the Panel to rethink their penalty levels and to develop more structure around the audit process to insure a level of certainty in the identification of non-compliances. The goal should be to develop a fair audit process that will be able to measure performance consistently over time.

6. Integrity Management

Q. What are the Company's comments and concerns with the Gas Safety Panel proposals for Non-Compliance With Integrity Management?

A. First of all, the Company would like to correct the record regarding a comment in the Gas Safety Panel Testimony which stated "The completed assessments of Distribution's systems have identified several threats which, if left unrepaired, could directly impact public safety. The rehabilitation projects to mitigate these threats prolong the asset life with lower remediation costs in the future, and avoid the need for costly full pipe replacement." The Company disputed the Panel's statement and Staff has since corrected that statement in their response to Information Request NFG-DPS-127-REVISED attached as Exhibit___(KDH-14). For the record, Distribution has no unrepaired integrity threats from its pipeline integrity

assessments. Distribution has one 6" diameter transmission pipeline, approximately 1.6 miles in length, that requires periodic assessments under pipeline integrity regulations. Distribution uses External Corrosion Direct Assessment as an assessment method since ILI is not possible given the pipeline's current configuration and operating conditions. The latest assessment of this pipeline was performed in 2013 and did discover a minor coating anomaly which was promptly repaired. A baseline assessment was performed in 2006 which also discovered some minor coating anomalies and the potential for AC corrosion. All coating anomalies were promptly repaired and an AC model was developed and Zinc ribbon installed to mitigate the potential for AC corrosion. It should be pointed out that these anomalies would not have been discovered by ILI, the assessment method proposed by Staff, since there was no metal loss present.

7. Plastic Fusions and Qualifications

Q. You previously discussed the Gas Policy Panel's recommendations concerning the plastic fusion situation. Do you also have comments and concerns with the Gas Safety Panel's proposals for Plastic Fusions and Qualifications?

A. Yes. The Company appreciates the Panel's comments regarding the

Company's response in addressing the non-compliance issue and mitigating the potential risks. The Company also appreciates the guidance provided by Staff in this effort.

Regarding the Gas Safety Panel's proposal that the Company be prohibited from recovering any costs associated with Case 14-G-0212 from ratepayers, and that any such costs be normalized out of the historical period, the Company has already stated that we agree that its ratepayers should not bear the cost for the Company to identify and correct any deficiencies arising out of its lapse in destructive testing. The Company supports the Gas Safety Panel position that the remediation costs be absorbed by Distribution in the interest of fairness to our customers. We do not agree, however, that it is appropriate for the Company to be double penalized as proposed by the Staff Policy Panel, with both the costs having to be absorbed by the Company and an additional penalty being imposed on top of that.

The Company has no objections or comments regarding the Panel's proposal for annual reporting of fusion inspection results in lieu of monthly reporting.

8. Inactive Accounts

Q. What are the Company's comments and concerns with the Gas Safety Panel

proposals for Inactive Accounts?

A. The Company is in general agreement with the Panel's recommendation "that all meters and services are required to be installed in a readily accessible location and be protected from corrosion and other damage, including any vehicular damage that may be anticipated." It is an ongoing process to attempt to relocate all meters to the outside where possible and permitted under law and individual circumstances. The Company proposes to continue its existing practices.

9. Annual Reporting

Q. What are the Company's comments and concerns with the Gas Safety Panel proposals for Annual Reporting?

A. The Company agrees with the Panel's recommendation.

Rebuttal to Staff Gas Rates Panel

Q. What areas of concern do you have with the Gas Rates Panel's testimony?

A. I have concerns related to the Panel’s proposed reduction in the LPP replacement budget, annual reporting requirements and proposed unit cost cap.

1. LPP Replacement Budget Reduction

Q. What concerns do you have with the Panel's proposed $1.39 Million

reduction in the Company's Rate Year Budget related to LPP replacement.

A. In their testimony, the Panel accepted the Company's analysis and proposed unit cost for 2016, However, the Panel does not believe that the Company's proposed 4.3% increase in unit costs for 2017 is reasonable . Specifically the Panel does not agree with the additional 5% for “ramp up costs”, for bid contractors and Company crews , due to increasing LPP mileage targets. The Panel believes that because the Company has already replaced 97.35 miles of LPP in CY 2015 and because the target for 2017 is 100 miles, a 5% ramp up cost is not required. The Panel believes the proposed two year ramp-up from 95 to 105 miles should allow a ratable transition for bid contractors to plan for the additional work. As a result, the Panel is only proposing a 2% annual increase to the Company's proposed unit cost, beyond 2016, which was based on 95 miles of LPP replacement.

Basically the Panel is only allowing for 2% annual inflation to the Company's pipeline replacement budget while the Company ramps up its annual LPP replacement rate 10 miles or 10.5% over two years. Other than the proportionate increase in total budget for the additional mileage there is no allowance for ramp up costs from 95 miles to 105 miles of LPP replacement.

The table below shows the Company's main and service replacement spending and unit costs for the recent period which highlights the Company's increasing LPP replacement costs at a 95 mile LPP replacement rate.

Main and Service Replacement Costs	**FY 2014 ACTUAL**	**FY 2015 ACTUAL**	**FY 2016 FORECAST**
Spending	$31,854,679	$34,318,397	$36,789,322
% Increase		10.0%	7.2%
LPP Unit Cost/Mile	$340,328	$359,732	$387,256
% Increase		5.7%	7.7%

The Panel's allowance for only a 2% inflation rate for the Company's LPP budget does not take into consideration our pricing experience over the past three years and it does not consider increasing overheads such as inspection, engineering and design, additional training and qualification, increasing contractor administration costs, etc. Staff's assumption is that these costs will increase proportionate to the LPP mileage replaced, which is simply not the case and has not been our experience.

Staff believes that a two-year ramp up will allow our contractors to plan for the additional work, however, Staff fails to recognize that our contractor workforce has a finite pool of people to draw from when hiring new employees. Utility construction work requires a certain level of aptitude

and not all construction workers qualify. Another dynamic is that some of our contractors do not want to get any bigger and are not willing to add personnel.

In 2015 the Company installed approximately 98 miles of main, to retire 109 miles of main, of which 97 miles was leak prone. The fact that the Company replaced 97.35 miles of LPP main in 2015 does not mean that it will be that much easier to get to 100. Each year you start at zero. The mix of work can vary from year to year. Some years it is a struggle to meet the target and others are easier and result in more mileage. In addition to LPP replacement the Company's construction budget must also accommodate non-leak prone pipeline replacements to relocate mains due to conflicts with highway and municipal construction projects and system improvement projects. The Company is currently working on a relocating a large diameter pipeline for a bridge reconstruction project. The replacement will install approximately 900' of 24" main at an estimated cost of $1.5 Million ($8,800,800/Mile). This project will comprise a significant portion of our 2017 capital replacement budget, but it will not result in any LPP replacement. When the Panel proposes to reduce the Company's construction budget in order to insure that we are controlling unit costs, they

are taking away any flexibility that we have in absorbing this type of project. At a reduced capital budget, the Panel wants the Company to replace more pipe, replace the riskiest pipe, replace the pipe with the highest volume leaks, reduce year-end leak backlogs solely through our LPP replacement program, increase inspections, etc. If we are not able to accomplish all of these items under the proposed reduced budget, then we may be subject to significant negative revenue adjustments for not achieving LPP replacement , leak backlog and net plant targets. The Company simply cannot agree to accomplish all of these items with a reduced capital budget.

2. Annual Reporting

Q. Will the Company be able to comply with the significant new reporting requirements proposed by the Gas Rates Panel?

A. No. The Company does not have the systems in place nor the personnel to comply with the Panel's new reporting requirement at this time. The Company has already testified that it would not be able to meet new reporting requirements proposed by the Gas Safety Panel without investing in a computer system or hiring additional personnel to maintain and report on the requested data manually.

Some of the information being requested by the Gas Rates Panel is

similar or has some of the same elements as existing reports submitted to Staff or that have been proposed in this proceeding by other Panels. The annual report requested by the Gas Rates Panel will take a considerable amount of time to prepare and it will require an ongoing effort throughout the year to track cost and schedule variances for each project. This report will also require a significant effort by our project engineers to develop a narrative on project design, permitting and or construction status (including a detailed construction schedule for each project) for any ongoing projects. Since the Company is in the safety and service business project schedules are constantly changing based on new information and changing priorities. For most capital construction projects in our backlog of approved work, the Company does not establish a project schedule until the project is added to the weekly construction plan. To establish schedules and track variances on a monthly basis, as suggested by the Panel, would be time consuming, impractical and would have little value.

The Company would propose that it continue to submit the semi-annual LPP Replacement Report and Annual Capital Construction Report, in their current formats, as agreed to in the Joint Proposal in Case 13-G-0136. If these reports will no longer work for Staff, the Company would propose

meeting with Staff to develop enhancements that would provide Staff with the information they need to monitor the Company's programs, but that can be accomplished at a reasonable cost and commitment of resources.

2. Unit Cost Cap

Q. The Gas Rates Panel is recommending a cost per mile cap as an incentive for the Company to control costs, incent synergistic opportunities and limit customers' bill increases. Does the Company agree with the Panel's proposal?

A. The Company does not support the reduced unit cost cap calculated by the Panel. The Panel has underestimated the cost for standard LPP replacements and have excluded the substantially higher cost per mile of high pressure and large diameter LPP replacements from their analysis. Therefore, the Company respectfully disagrees with this feature of the proposal as the Company has shown that it has always carefully managed its construction costs; Staff has no reason to believe this will not be the case going forward. Due to the varying nature of unique construction projects, the proposed cap could expose the Company to financial loss despite the fact that the Company may have undertaken the most reasonable and effective construction practices for a particular situation.

Q. Does this conclude your rebuttal testimony?

A. Yes, at this time.

A.L.J. LECAKES: Mr. Miller, Mr. House's exhibits?

MR. MILLER: Yes, Your Honor.

BY MR. MILLER: (Cont'g.)

Q. Mr. House, do you have in front of you a document that was attached to your direct testimony entitled Exhibit KDH1?

A. Yes, I do.

Q. Is that document prepared by you or under your supervision and direction?

A. Document KDH1 was prepared by James D. --. I included it in my testimony.

Q. Yes. Are you also sponsoring Exhibits to your rebuttal testimony?

A. Yes, I am.

Q. And are those Exhibits KDH2 through KDH14?

A. That's correct.

Q. And were they prepared by you or under your supervision and direction including those that you took from other sources?

A. Correct.

MR. MILLER: Your Honor, may we have

Mr. House's exhibits marked for identification please?

A.L.J. LECAKES: Absolutely. So KDH1 we will mark as 178, KDH2 179, KDH3 180, KDH4 181, KDH5 182, KDH6 183, KDH7 184, KDH8 185, KDH9 186, KDH10 187, KDH11 188, KDH12 189, KDH13 190, and KDH14 191.

MR. NICKSON: Your Honor, I just want to note for the record that the testimony of Mr. House both direct and rebuttal testimony that was given to the court reporter is the corrected testimony that was circulated to the parties last Friday, September 30th.

A.L.J. LECAKES: Great. Thank you for that clarification. Were there any corrections to the exhibits?

MR. NICKSON: Not for Mr. House, no.

A.L.J. LECAKES: Okay. Thank you. Is the witness available for cross examination?

MR. MILLER: Yes, he is, Your Honor.

A.L.J. LECAKES: Staff?

CROSS EXAMINATION

BY MS. WOEBBE:

Q. Good afternoon, Mr. House.

A. Hi.

Q. Mr. House, can you please refer to page two, line 19 of your rebuttal testimony. On page

two, line 19, you state unintended negative consequences can result if staff establishes a net plant target that does not consider the time lag in converting capital spending to plant in-service. Do you agree?

A. I am sorry, but on page 19, line 19?

Q. Page two.

A. Oh I'm sorry.

Q. Line 19.

A. I'm sorry.

Q. Of your rebuttal testimony please Mr. House.

A. I'm sorry. Could you state that -- that note again just so I have the right spot?

Q. Page two, line 19 where you state unintended negative consequences can result if staff establishes a net plant target that does not consider the time lag in converting capital spending to plant in-service.

A. Correct.

Q. Mr. House, did Staff adjust the timing of any of the company's capital projects?

A. No, they didn't.

Q. Mr. House, do you oppose this net plant target even though Staff did not adjust the

company's capital plant schedule?

A. Yes, I do.

Q. Isn't it true that since Staff did not adjust the company's schedule that any time lag in converting capital spending to plant in-service could only occur if the company does not deliver its own forecast capital plan?

A. I'm not aware who developed the net plant target and so I -- I assume that it was jointly agreed to by Staff and the company when I wrote this testimony.

Q. So Mr. House, do you agree that the company would be responsible for delivering its own forecast capital plan?

A. I do.

Q. And that any time lag in converting capital spending to plant in-service would only occur if the company does not deliver that forecast capital plan?

A. I don't agree with that. If the -- if the company -- it's very difficult to forecast -- you know -- sitting here today what our spending will be and which projects will come to fruition and when they'll come to fruition. We -- you know -- there's -- there are permit issues that you have -- you have to consider. There are

other projects could move in place of -- of potentially a large project so the large projects that do impact the net plant can be delayed and so it -- it's -- that forecast is just that. It's a forecast, but to tie a penalty to it, if -- if large projects don't come to fruition exactly when we forecast it then I don't -- yes, I don't agree with that. I don't think we should be paying a penalty for that.

Q. Do you agree that the company intends to deliver on its forecast?

A. Yes.

Q. Let's move on Mr. House. Please direct your attention to page 24, line 7 of your rebuttal testimony. On Page 24, Line 7 you state that the company has been able to maintain its leak prone pipe replacement program in part by using internal reports. Correct?

A. That's correct.

Q. In what areas does the company conduct internal reports?

A. Capital spending reports, bid plans, project schedules, completed project reporting. There's a variety of different reports that we use to ensure that we're on target and that we're going to meet our target by the end of the year and that our spending -- you know --

is in line with -- with our replacements.

Q. Mr. House, does the company conduct internal reports of its forecasted capital plans?

A. We don't match -- we don't match them up, the forecast to the actual spend -- we -- we don't like have any reports that compare that variance. We have the capital budget that we do compare variances to our capital budget -- our signed and approved capital budget. We do compare that. We do have reports that look at the variances from actual to capital budget.

Q. Can you please describe the internal reports?

A. Oh yeah, we have -- each -- each month we prepare a capital budget packet that goes through overview of all of our capital spending in the different plant areas and -- and what's remaining in the various areas. That's kind of a high level report and then attached to that we have a more detailed report that is -- that looks at each budget area, spending from budget, actual spending compared to budget and we compare that and then we have a graph that shows that and then we also have our large contractor projects. We have a listing of those and -- and what the remaining -- what the actual spend is, what the remaining spend is so that we can review those

and -- you know -- understand what we have remaining to spend yet on those projects and then we have a forecasted project list appears the projects that are yet to be bid or that have been recently bid and awarded and so we compare those -- we look at those projects and all those reports kind of feed into that first summary page there.

Q. Are these internal reports provided to management?

A. Yes.

Q. To the board of directors?

A. I don't believe they see that report -- the board.

Q. And I believe you did just state this, but can you just clarify, does the company monitor actual capital expenditures by month?

A. Yes.

Q. Okay. And same thing I believe you did just state this, but does the company track the percent of projects complete and the completion dates monthly?

A. No. Just large -- large projects we look at where the large projects are -- what -- where they are -- what point they are in phase of completion.

Q. Does the company have any internal

procedures that verify that projects are implemented in compliance with corporate procedures?

A. Could you ask that a different way?

Q. Sure. Does the company have any internal controls or procedures or quality assurance controls that would verify that projects are implemented in a way that complies with corporate procedures?

A. I'll -- we do a post investment analysis on our large projects and on our contractor projects to explain variances so those reports do -- after all the spending is completed on a project -- you know -- we look -- we do a comparison from budget to actual and then we explain variances in the various areas and we can install more pipe for some reason or we had contingencies that weren't considered -- you know -- in the original or unforeseen contingencies I guess I would say so we do report on those and I guess that kind of fit the mold of that.

Q. Mr. House, if a project significantly over- or under-runs budget forecasts or estimates, what actions might the company take?

A. Okay. Well, it's -- those reports are mainly used to inform future decisions so -- so for instance and we've kind of learned over time there's

certain areas of our system that have rock that you can encounter rock so we might -- we might create a -- an estimate for a project and it's -- you can't see underground so you don't know if you're going to encounter rock for sure.

Sometimes we will do test digs to ensure that we're going to encounter rock and then maybe in those areas, we will actually bid a rock item -- rock removal and select fill item so that we -- so that we're getting a competitive price for that typically though the company uses contingency pricing for those items.

We've got a whole list of contingency item prices that if they should be encountered by any contractor on any contractor project, we pay this price per cubic yard, per square foot, whatever -- whatever the unit is and those are typically -- they're -- they're low. They're not making money on those. They're just to help them recover their cost when they -- when unforeseen conditions are encountered, but sometimes if we think there's going to be an extraordinary circumstance on a project then -- then we will bid additional items -- kind of contingency items just to make sure that we're getting a competitive bid on those.

Q. It sounds like the company plans for

unforeseen circumstances?

A. Yes. Yeah, we do add a contingency to our estimates -- kind of a standard contingency.

Q. At what point in the process might the company know that there's a budget problem?

A. Our invoices have -- our invoices have quite a bit of information on them so you -- so we know exactly the percentage of contingencies and change orders that we're paying on projects and we also know the projected -- you know -- the estimated quantities to the completed quantities so we can see that as -- as it's occurring -- as we're getting invoices we can see those -- those issues.

Q. Can you explain how management reviews and approves project costs and schedule variances during the company's fiscal year?

A. Yes. The -- the company -- so individual project costs do you mean or just accumulated project costs?

Q. Let's start with individual --

A. Yes.

Q. -- and if there's a different procedure then --.

A. Okay. Yes, so -- so individual

project costs are tracked like I said through those invoices that have summaries of project costs and then in that capital budget packet that we -- that we review monthly, all of those contractor large projects are listed and so we're looking at those costs and contingencies percentages and change order percentages so -- so we do that on a monthly basis, but we're also looking at individual projects as the invoices come in. I would point out though that for schedule variances, we -- we -- we don't like to establish hard schedules especially for our contractor projects because it -- it tends to drive pricing up.

If we -- if we bid projects and we say you have to start this on May 1st and complete it on July 15th and if they get that job and now we bid another job that they could do -- you know -- that they could do in the same time frame, but they can't bid on that job because they committed to this very tight time schedule on the first project. Then -- then they can't bid on it so we don't have enough bidders so when we -- when we bid our work at the beginning of the year and through our bid -- bid phase in the late spring and early summer, we're using very liberal completion dates.

We'll use dates like September 15th,

September 30th if we're bidding in early summer we'll use date of October and November just so we can get those projects wrapped up before the heating season because a lot of them are -- you know -- they may be to solve water outages or pressure problems or leakage so we want to make sure that those things get wrapped up before the winter so we want to -- we want to give our contractors as much flexibility as possible by not -- by not -- you know -- holding them to very tight schedules this way they can keep bidding and then they can work those projects into their schedule for the most efficiency essentially and then we feel -- we know we get better prices by doing it that way.

Some projects -- highway projects that have to be done by a certain date, certain system related problems if we have water outages and we want to set a hard date then we will do that for -- for some projects, but typically we don't establish hard schedules.

Q. So Mr. House, for an individual project where there is a hard schedule established, how might management review and prove a project cost variance for that project?

A. Well, every invoice is reviewed to ensure that the -- that the costs are appropriate and in

accordance with the bid documents so -- you know -- they're -- they get -- our contractor bids $15 per foot of 2 inch pipe, that's what they're getting. If there are contingencies and variances like contingencies in change orders on the project, those are approved at -- at the inspector level, the foreman level, the district manager level, the staff engineer level and the engineering manager level so they go through multiple phases of review before that invoice is approved for payment.

Q. A few questions ago you explained how the company plans for unexpected costs or circumstances --

A. Yes.

Q. -- in individual projects. How might the company reconcile an annual budget differential versus an actual performance?

A. Well, when we look at a total budget we're -- we're not even looking at each individual project. We're just looking at all the projects as a group and how is our spending coming in and, for example, then we may delay bidding projects so we'll control our budget to some degree to the extent we can. We may -- if we see our prices are coming in higher or our -- our cost are coming in higher then we can delay the bid and -- and our fiscal year ends September 30th so we can -- we have

some latitude where we still have some construction season after the fiscal year so we can kind of time our bids so that we can try to hit our spending at the end of the fiscal year and I think we do a pretty good job of it based on our exhibits.

Q. Mr. House, how and when does the management report to the board of directors on the status of the current fiscal year capital investment plans in progress?

A. Yes, I'm not totally aware, but I know they do review the budget performance at the board of director's meetings for the -- for the total corporation and for each of the subsidiaries, but I'm not privy to how that's -- how that's done.

Q. Are you aware of how often the board of directors meet?

A. I believe they meet four times a year, but I'm not certain. I'm sure that's --.

Q. Mr. House, can you explain how the company might include changing priorities during a fiscal year?

A. I'm sorry. Could you say that again?

Q. Sure. How does the company include changing priorities during a fiscal year?

A. Again, kind of by delaying those bid schedules. So -- so you could -- highway projects are tough to forecast because of the timing of them and I -- and I mentioned in my testimony right now we're working on a really large one. It's a 1.5 million dollar project and -- you know -- when you're going to get your environmental permits for those and you're balancing that with the highway department says you have to be out of our way by this date, sometimes that can be a moving target so we just -- we do like I had mentioned a little -- you know -- we'll adjust bid schedules to account for that. Sometimes you can't adjust and you just got to do -- you know -- you just got to do it. You got to get the work done and -- and so we'll -- we'll do what we can to adjust schedules, but -- but the work has to get done.

Q. How does the company account for redirecting resources during a fiscal year?

A. How do we account for it? I would say our contractor group is a pretty known quantity and that's -- that's who -- that's who we deal with significantly; however, our company construction crews do -- and -- and if we're talking about leak prone pipe replacement, our company crews do about 30% of our replacement work so they're a big -- a factor in that. Sometimes if you get

inclement weather, bad winters, things like that you can't do as much -- as much construction during that -- that period and those people's focus shifts to leak repair, leak surveys, leak repairs during that cold weather -- during frost conditions so I guess that can throw you off your plan.

This last winter though we had a very mild winter so our -- so our company people were able to continue constructing through the winter doing pipeline placements and things like that so that -- that was a little -- somewhat unexpected that we would have such a mild winter so we did spend capital a lot quicker earlier in the fiscal year and we had to try to make adjustments for that at -- you know -- by -- we have three construction groups that work on our projects: Company crews, blanket contractors, and bid contracts and so the one that we can kind of use as the gas pedal are our blanket contractors. We have to keep our company crews busy all the time. Our bid projects -- you know -- those -- those have -- we've committed to that work. The blanket folks though if we see that we've constructed too much through -- we were able to get a lot of construction work done during the winter months then we'll just slow down the -- the number of projects that we're feeding to

that blanket contractor group, but we only have so much latitude especially -- you know -- with the -- with the leak prone pipe replacement program because in the end, we have to hit the 95 miles. So whatever we have to do to hit that target, we have -- we're going to do so if we have to continue to release work to -- to hit that target then we have to do it.

Q. Similarly, please explain how the company includes process improvements during a fiscal year.

A. Process improvements -- I guess I would say -- I'm trying to think. I'm trying to come up with a good example for you. I guess our -- when we're -- when we're utilizing our pipeline contracts -- I'm not sure if this is -- you would call this a process improvement, but we'll change sometimes the types of work that we'll do during a certain period of time. I -- I gave an example in my -- either testimony or rebuttal testimony, I forget which one it was, but it was -- you know -- to try to hit the net target. We were finding that in that first year of 2014 when we had the -- the -- the additional 15 mile leak prone pipe replacement target and we -- we didn't get the rate settlement until later in the year, we really had to ramp up quickly with our

projects and spending -- you know -- number one to hit the net planned target and number two to hit the 95 mile target.

What we started seeing our -- our contractor pricing really take off because they knew they kind of had us -- they had us over a barrel and the prices started to escalate so we started to look at ways where we could still get this stuff done, but without escalating the cost. So we bid a couple of large diameter projects at that time to -- to get different contractors in the mix -- get -- cause the guys who were doing our -- our -- you know -- our normal leak prone pipe replacements, plastic projects, they had plenty of work. Their prices were escalating. We said we got to get -- you know -- we have to hit this net plant target. We got to hit our 95 mile goal.

Let's bid some projects that will use a different contractor group. Sometimes we will do it. We will shift work. We only have a certain number of contractors who will work in the city in the urban areas -- you know -- maybe a handful of them who are competitive in the urban areas so when we see their pricing start to escalate, then we'll -- we'll stop bidding in that area and -- and then we'll start -- we'll work on projects in

rural areas and then that -- typically what happens then those guys start hey when are you going to bid more work? And then when you release more work, their prices seem to come back in line. So I guess that's a process improvement maybe.

Q. Mr. House, does the company think that it's important for the commission to track the company's leak prone pipe replacement performance?

A. Yes, I mean I -- yeah, with any goal you have to track your performance. I -- I can recognize that.

Q. I have a few yes or no questions Mr. House.

A. Okay.

Q. Perhaps you may want to answer subject to check because they're specific.

A. Got it.

Q. In fiscal year 2013, did the company remove 80.6 miles of leak prone pipe?

A. That sounds correct.

Q. In fiscal year 2014, did the company remove 93.6 miles of leak prone pipe?

A. Yes, now that's 93.6 miles of I believe that's bare, cast, and rod iron pipe and then

there was a couple of miles or a mile and a half of leak prone plastic which does qualify under that.

Q. And that's specific to fiscal year 2014, that type of pipe?

A. That's 2014, yeah. Well, you used -- you gave a number of 93 something and --

Q. 93.6

A. -- and I know we did over 95 for our target so I think the 93 was bare, cast iron and rod iron pipe and then there was additional mileage for leak prone plastic that got us over the 95 miles.

Q. In fiscal year 2015, did the company remove 95.4 miles of leak prone pipe?

A. I think that's probably bare, cast, and rod iron.

Q. Thank you. Sticking with a yes or no answer, in 2015 did the company renegotiate its blanket contracts?

A. At the end of 2015 for prices effective in 2016.

Q. Mr. House, how long of a term is the company's blanket contract?

A. The contracts are 3 one year renewable contracts so at the end of each year the contractor has an

option to -- to not renew essentially so committed to a year. Their prices are good for three years when they bid on the work, but they can get out each subsequent year.

Q. And how often do contractors renew a 3/1 year contract for the full 3 years?

A. They -- it's -- there's very few -- there's very few instances where -- where they don't continue to honor their contract.

Q. Referring back to your direct testimony, please refer on page 9, line 10 through 18, of your direct testimony --.

A.L.J. LECAKES: Counsel, let everybody find it first.

MS. BRIDGET WOEBBE: Sure.

A.L.J. LECAKES: Thank you.

A. I'm sorry. What were the lines again?

BY MS. BRIDGET WOEBBE: (Cont'g.)

Q. Lines 10 through 18 --

A. Okay.

Q. -- of your direct testimony.

A. And could you read the statement cause mine are --

Q. Yes, sir. The company's top priority is safety --

A. Yes.

Q. -- and we firmly believe we are presently maintaining a safe and reliable system with our current approach to leak prone pipe replacement.

A. Uh-huh.

Q. Then a few lines down, Mr. House, you discuss the company's proposal to accelerate leak prone pipe replacements. Correct?

A. Correct.

Q. Does the company follow pipe installation procedures?

A. Yes.

Q. What are some purposes of the company's pipe installation procedures?

A. To ensure safety, number one, and regulatory compliance. There's -- there's -- you know several elements of pipeline replacement that have regulatory requirements associated with them so our procedures address those as well.

Q. If the company and company contractors follow these procedures, do you expect newly installed pipe to leak or fail shortly after installation?

A. No.

Q. Mr. House, how long do you expect

plastic pipe to last in the ground?

A. Age wise if it doesn't have to be replaced for some other reason, I'm -- I don't know. I have no idea what it is -- what the number is. I'm not aware of -- I know they have forecast a lot of it depends on temperature, stress, pressure, things like that. I'm not sure, but I will say we can install pipe -- we can install pipe today and end up having to replace it next year, plastic pipe, because of a highway project or we might do a short replacement on a street with bare steel pipe in the middle -- you know -- and we've got a leak that we've got to -- we don't want to do the whole street at this time. We'll have to do like a 40 foot or 80 foot replacement to get -- take care of the leakage cause it can't be clamped so we'll do a short replacement like that and it'll be say low pressure -- say it's a four inch low pressure main in the urban area. We'll do that short replacement.

Then we'll -- we might come back two or three years later when we're -- there has been more leak history develop on that pipeline and it's part of our bid plan and we'll replace all the pipe on that street. It's actually more expensive to tie back in and upgrade that 80 feet of pipe that we just installed -- it's cheaper to

just run right by. So we'll replace that pipe that we just installed 2 years ago -- that plastic pipe that we just installed 2 years ago.

Q. Mr. House, what's the purpose of the company's quality assurance and quality control program?

A. To ensure that our personnel are following procedures in the field.

Q. Mr. House, compared to cast-iron in the hypothetical that you just ran through having to replace it --?

A. Yes.

Q. How long would you expect the plastic pipe to last as compared to a cast-iron?

A. I hope it lasts as long as the cast-iron because some of the cast-iron was installed in the 1800s and it's still out there so it's been in the ground for over 100 years. I hope it would. I don't know.

Q. Mr. House, please explain how the procedures -- the quality assurance and quality control procedures might prevent future damages to the extent that prevention is possible.

A. Yeah, now when you talk about quality assurance, I think we're talking about where we have a group that goes out and audits our field people to ensure

that they're complying with procedures. I think we're not talking about the procedures themselves.

Q. Both, Mr. House.

A. Okay. Okay. So then could you ask the question again? I lost my --.

Q. Sure. Can you please explain how the procedures prevent future damages to the extent that prevention is possible?

A. Construction -- you mean the construction procedures when we're installing the pipe?

Q. Yeah.

A. Oh, okay. That's great. That's a good one. So yeah, we have -- you know -- especially like with newer plastic mains, you -- you know -- you're installing wire. We're bringing the wire above grade so that we can locate it easier. We're using 3M marking balls. We're taking more measurements then -- you know -- nowadays then we did back in the earlier days when plastic was installed in the 70s and 80s and so I think our construction procedures have certainly improved over time which -- to make our facilities more locatable.

Q. Mr. House, compared to cast-iron, do you expect plastic pipe to leak at the joints after installed?

A. I -- I would have -- I have the expectation that the joints will not leak after they're installed.

Q. For both cast-iron and plastic pipe joints?

A. I can't speak to cast-iron because I -- I wasn't involved in its installation. I mean the cast-iron joints do have a high -- a high tendency to leak.

Q. Mr. House, how many inspectors do you have per construction job?

A. Oh per job? Typically one inspector -- I can see there may be a large job where they might supplement, but it's typically one inspector or we have -- we may have one inspector that watches two or three projects depending on how many projects are going on in that -- in an area so they -- they may not be full time inspection. They may be partial inspection and I did address that in one of the data requests that Staff had.

Q. Thank you, Mr. House.

MS. WOEBBE: Your Honor, I have no more questions.

A.L.J. LECAKES: Is there any other party that wishes to cross? Okay. I have a few questions before I would turn you over for redirect. One of the

subjects the counsel for the staff go into involved the timing and you were talking about how some of the projects that have certain governmental requirements or whatever will force the company to -- to require a hard end, but others have -- have a soft end.

THE WITNESS: Uh-huh.

A.L.J. LECAKES: What procedures does the company have in place to manage a project that a contractor is working on that has a soft end like that to make sure that the contractor is working diligently to complete that project timely irrespective of the fact that the -- the --

THE WITNESS: Right.

A.L.J. LECAKES: -- completion date is many months down the road?

THE WITNESS: Slipping. Right. Yeah, that's a good -- that's a good one. Our -- you know -- our operations folks are very in tune with that because it just costs us more money if contractor A can do it in a month and contractor B takes two months. Well, that costs us more money and overhead and inspection time and so we -- we do -- and our contractors -- we have a good contractor group that's been working for us for many years. It's not -- it's not like -- you know -- they're

in and out constantly so -- so we've worked with them over the years and they know what our expectations are, but if we start to see slippage then we're having meetings with them and -- and periodically we do have to elevate those meetings to -- you know -- ownership -- contractor ownership.

But typically those delays are addressed on the project by the field personnel and then also the contractors get -- they know that they're evaluated after each project too so they -- there's some incentive for them to -- to hit I guess our expected -- they -- contractors have to send in a Gantt chart to us even though the project might only have a -- a September 15th completion date and we bid it in March. When they bid the project, they have to give us a Gantt chart so we're kind of controlling the schedule based on what they originally told us.

Now say they get three or four other jobs, we'll ask them to send us a chart as to how you're going to fit all these projects in and get them all done by September 15th because we may not award that project.

Let's say that fourth job, we might look at it and say man their -- their pricing -- they're only a thousand dollars cheaper than this other contractor. How

are you going to get this -- how are you going to get all of these -- all of these projects completed by September 15th and then they'll give us an overall Gantt chart. If we're not happy with it, we give it to the second bidder.

A.L.J. LECAKES: Thank you. You just eliminated about four additional follow up questions in that answer.

THE WITNESS: Great.

A.L.J. LECAKES: Can you just turn to page 29 of your rebuttal testimony please -- the rebuttal?

THE WITNESS: Okay.

A.L.J. LECAKES: Do you have it?

THE WITNESS: Yes.

A.L.J. LECAKES: Okay. I didn't mark the page line down, but on page 29 at some point you're discussing a change made to the staff gas safety reporting guidance that was issued December 11, 2015.

THE WITNESS: Correct.

A.L.J. LECAKES: There's a previous -- so previous to the change, the reporting excluding hand digging damages and homeowner damages where there was no locate request.

THE WITNESS: Correct.

A.L.J. LECAKES: Can you define for me hand

digging damages and homeowner damages or give me examples of those?

THE WITNESS: Yes, say a contractor was going to put in a fence and they were digging a post hole using a shovel --

A.L.J. LECAKES: Okay.

THE WITNESS: -- and not an excavator or an -- one of those auger powered equipment. That would be a hand damage -- hand digging damage.

A.L.J. LECAKES: Okay. And when you say there was no locate request, is that no call in to the call before you dig hotline?

THE WITNESS: Correct.

A.L.J. LECAKES: Okay. So what kind of damage can a shovel or a post hole digger cause?

THE WITNESS: Yeah, they can -- it can -- well, for some of our plastic services are only 5/8 inch tubing.

A.L.J. LECAKES: Okay.

THE WITNESS: So -- and it's plastic so you can take a shovel and put it right through the -- through a plastic service -- you know -- a one inch or a half inch plastic service. For a main line, it's less likely, but if you hit it hard enough you can put a gouge in it which

could shorten the expected life of the plastic because it will tend to fail at that location. It might last 10 years, but it will eventually fail if they nick it and don't report it.

A.L.J. LECAKES: If I -- if I understand your testimony there correctly, you say that that change has caused an additional 30 incidents in the reported 2016 year to date performance. Is that right?

THE WITNESS: Yes -- yes, so the old reporting and the old reporting guidelines, we were not to include those damages --

A.L.J. LECAKES: Right.

THE WITNESS: -- in the metric. In -- in the new guidelines, we -- there -- we do report those damages in the metric.

A.L.J. LECAKES: And -- and when you say an additional 30 incidents, so that's between January 1st of this year and -- and August/September of this year?

THE WITNESS: Yes, 30 more damages. Correct. Yes.

A.L.J. LECAKES: And the targets are measured on a per 1,000 ticket basis, how many tickets a year does the company get roughly?

THE WITNESS: I could -- I'm going to have

to look that up.

A.L.J. LECAKES: That's fine.

THE WITNESS: I can do that real quick.

A.L.J. LECAKES: Take your time.

THE WITNESS: So in -- in 2015, we had 95,284 one-call tickets. The previous year we had 88,000 -- no, previous year we had 88,724.

A.L.J. LECAKES: Are -- are -- do those happen roughly seasonal because of the ground hardening in the winter or do they happen all year round?

THE WITNESS: The tickets probably mostly occur in -- in the better weather because that's when people are out doing construction projects so typically those -- those tickets -- more tickets I believe occur during the summer months -- spring, summer, fall months when people are constructing.

A.L.J. LECAKES: I have no further questions. If the company wants to consult with the witness as to redirect, we will take a few minutes.

MR. MILLER: Thank you.

A.L.J. LECAKES: Off the record. Thank you.

(Off the record)

A.L.J. LECAKES: All right. Back on the

record. So -- Mr. Miller, do you have any redirect for Mr. House?

MR. MILLER: I do, Your Honor.

A.L.J. LECAKES: Okay. Proceed.

MR. MILLER: Thank you.

REDIRECT EXAMINATION

BY MR. MILLER:

Q. Mr. House, do you recall some questions by Ms. Woebbe about your construction budget versus the amount you actually booked in capital in a given year?

A. Yes.

Q. Staff is proposing a net plant true up, are you aware of that?

A. Yes, I am.

Q. If the company underspends its capital then the true up mechanism would apply. Right?

A. Yeah, if -- yes, if we don't book -- if we don't get into plant a sufficient number of projects onto the books then we could spend the money, but it might -- it might not all go onto the books during the period so -- so yes, we do have to spend the money to get it on the books, but there is a time lag from the time you're -- from your spending for your actual capital spending to

when you actually hit the plant.

Q. So you're talking about the difference between spending and when the plant is actually booked?

A. Correct.

Q. And there's a lab with that?

A. There is and the net plant true-up is based on when -- when the plant hits the books.

Q. What are some of the construction budget during the year that are unforeseen when you make that budget?

A. Well, we talked a little bit about it. Weather can -- can impact us significantly. I mean -- you know -- we're in Buffalo, New York. You get snow storms. You get inclement weather and so it can -- you know -- prior to this last winter, we had some pretty tough winters and so we didn't -- we weren't able to construct through the winter time and with our new -- with our higher targets now -- you know -- more leak prone pipe replacement we really have to try to construct as much as possible all year round and so we do have to bid some winter work and hopefully the contractors can get it done.

So weather is the primary driver with changes to the schedule. If we can't get it done in the winter, then we have to do more during the construction

season and that -- you know -- and that if we can't spread it out, it can tend to drive costs up somewhat and then the other thing or just unforeseen projects like I -- I had mentioned -- you know -- the highway projects or even new business projects -- you know? That takes contractor resources from pipeline replacements. If you get -- you know -- a bunch of new subdivisions or an extension -- you know -- we bid that work to get it completed in a timely manner and -- and so that contractor is busy doing that stuff and they're not doing the leak prone pipe replacement.

So there's a lot of different pressures, but we go into the year with a plan. Here's what we want to do. We have a bid plan, but we know that that's going -- it's -- it's going to change throughout the year based on unforeseen circumstances.

Q. One final line, Mr. House, do you recall a dialogue with Ms. Woebbe about leak prone pipe replacement -- do you recall you were asked questions about certain time periods including fiscal year replacements and calendar year replacements, is the company subject to a metric for leak prone pipe replacement?

A. Yes.

Q. Is that on a calendar year or a fiscal year basis?

A. That's on a calendar year basis.

MR. MILLER: We have nothing further, Your Honor.

A.L.J. LECAKES: Staff, any recross? Mr. House --

MS. WOEBBE: One question, please Your Honor.

A.L.J. LECAKES: Okay.

RECROSS EXAMINATION

BY MS. WOEBBE:

Q. Mr. House, can you please just clarify with what a large project is? Is that measured in terms of the dollars or miles replacement?

A. It could be both. It could be -- for example, I'll use this 1.5 million dollar project that we're talking about. It's - it's one contract that's using -- you know -- a contractor that typically doesn't do our standard distribution work. It's big bucks that come out of our budget. So that -- in that case, it's not such a -- it's not a giant project, but it's a costly project. That impacts us. But then you -- then there are just very large projects that can have an impact as well

like if -- if they're doing a streetscape project -- you know -- in a -- through a town and we have to relocate a bunch of our facilities, those -- those can take months -- you know -- a couple of months to do so you're essentially tying up contractor crews for a long period of time. So it's both. It can be size of project, scope, and cost of project.

Q. Just one more question Mr. House, when is a project manager assigned? Is that at all tied to it being a large or small project?

A. Yeah, I mean we use -- the way we do it at National Fuel, we assign a project engineer to -- to those large projects and -- and they're responsible for -- for -- for bidding the project and for monitoring the invoicing and the spending of the project and then their counterpart in operations is the operation -- is an operations supervisor who is responsible for that project so they kind of work in tandem. If there's technical issues then the engineer gets involved. If there's changes that need to be made on the project, the project engineer gets involved. Other -- otherwise the projects are managed by the operations field supervisors.

Q. Thank you, Mr. House.

A.L.J. LECAKES: Mr. House, I -- I do

have one follow up to Mr. Miller's questions. As far as the lag goes, do the difference between the plant closing and the plant being booked, on the front end of the reporting period though isn't it true that there's plant that can close before the reporting period started that doesn't get booked until after the reporting period?

THE WITNESS: Yes, that's true. If I could add though?

A.L.J. LECAKES: Please do.

THE WITNESS: There -- there's -- that's true as long as the spending is consistent like say you're doing 80 miles every year, every year, every year, that -- that should be fine because you're always getting some spillover from the previous year's spending and some of your spending at the end of this year is going to hit next year, but when you ramp up, that's -- that's where it can become a problem and -- and -- and typically the way our fiscal year operates from October to September 30th, you're not starting those ramp up projects until the spring. You've got 6 months of a fiscal year in typically before you're starting those projects.

On that net plant target goal, you get more credit the earlier you book the costs because it's kind of -- it's an average monthly net book value is my

understanding of how it works and -- and so if you can book it -- if you can book it in in the first month of the fiscal year, you get 12 months of that average. If you book it in the last month of that fiscal year, you get one month in the average so it's better to push the projects earlier in the fiscal year, but because of our construction season it's difficult to do that and then I know we're proposing -- we're proposing to ramp up our large diameter and high pressure pipeline replacements.

Those projects are going to have an uncertain schedule because they -- the high pressure projects are going to require Article 7 filings. They're going to require environmental permitting and we're finding that on those types of projects in our sister companies -- our transmission companies -- it's -- it -- those permits are taking longer and longer to obtain and so it could tend to push that -- push that spending and that getting that project in service to later in the fiscal year.

A.L.J. LECAKES: I appreciate that. Is Mr. House scheduled on a panel after this or is he just appearing by himself as a witness?

MR. JOSEPH DEL VECCHIO: I believe he's just appearing by himself at this point.

A.L.J. LECAKES: Okay. Great. You're excused then.

MR. HOUSE: Thank you.

A.L.J. LECAKES: Thank you very much.

MR. HOUSE: Thank you.

A.L.J. LECAKES: Why don't we take 5 minutes while the Gas Safety Panel from Staff gets up to the stand? Off the record.

(Off the record)

A.L.J. LECAKES: Are we ready? Let's go back on the record. Staff has called the Gas Safety Panel up. Panel, could you please identify yourselves individually by name and your business address?

MR. PATRICK RAICHEL: Patrick J. Raichel, 295 Main Street Room 1050, Buffalo, New York.

MR. CHRISTOPHER STOLICKY: Christopher Stolicky, 3 Empire State Plaza, Albany, New York 12223.

MR. MATTHEW DISALVO: Matthew D. Disalvo, 295 Main Street Room 1050, Buffalo, New York.

MR. MICHAEL PASINELLA: Michael Pasinella, 3 Empire State Plaza, Albany, New York, 12223.

A.L.J. LECAKES: Okay. Panel members, can you please stand and raise your right hands? Panel members do you swear or affirm that your testimony given

today will be the truth and the whole truth?

MR. RAICHEL: Yes.

MR. STOLICKY: Yes.

MR. DISALVO: Yes.

MR. PASINELLA: Yes.

PANEL; Sworn

A.L.J. LECAKES: You may be seated. Mr. Favreau, could you please lead the panel into getting their testimony and exhibits into the record?

MR. FAVREAU: Yes, Your Honor. Initially also I'd just like to state that this is the corrected testimony and the correction was -- I can call it an updated testimony because Bill Wade is not -- was not available for the next couple of weeks so he was taken off the panel and Chris Stolicky was put on the panel so in the testimony is -- where every reference to Bill Wade there's Chris Stolicky and then Chris Stolicky's C.V.

A.L.J. LECAKES: Okay.

MR. FAVREAU: And he adopts the testimony.

A.L.J. LECAKES: Right.

DIRECT EXAMINATION

BY MR. FAVREAU:

Q. Panel, has the 57 page pre-filed

testimony before you been prepared by you or under your supervision?

A. (Stolicky) Or adopted?

Q. Well, we already mentioned it.

A. Yes.

Q. Do you wish to make any changes to that testimony?

A. No.

Q. If I were to ask you these questions in that testimony today, would your answers be the same?

A. No. Yes, there would be no changes. Sorry.

Q. Thank you. That's okay.

A. I think we already did the changes.

A.L.J. LECAKES: For the record purposes, the panel indicates that these questions were asked in the testimony as it appears and the answers were given, there would be no changes and that it would be exactly as it appears in that pre-filed testimony.

MR. FAVREAU: Your Honor, I ask that that testimony with Gas Safety Panel be incorporated into the record as if given orally today.

A.L.J. LECAKES: So granted. At this point in the record in the transcript, it should appear

the file 16-G-0257 Gas Safety Panel Updated Testimony on the Staff supplied testimony disk.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

National Fuel Gas Distribution Corp.

Case 16-G-0257

October 2016

Prepared Testimony of Staff
Gas Safety Panel

Christopher Stolicky
Utility Supervisor (Safety)

Patrick Raichel
Utility Engineer 3

Michael Pasinella
Utility Engineer 2 (Safety)

Matthew DiSalvo
Utility Engineer 1 (Safety)

Office of Electric, Gas, & Water

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

PANEL CREDENTIALS

Q. Members of the Gas Safety Panel, please state your names.

A. Christopher Stolicky, Patrick Raichel, Michael Pasinella, and Matthew DiSalvo.

Q. Mr. Stolicky, do you have knowledge of and adopt the testimony that was filed by the panel on August 26, 2016?

A. Yes.

Q. Mr. Stolicky, please state your business address.

A. My business address is New York State Department of Public Service (Department), Three Empire State Plaza, Albany, New York 12223.

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

A. I am employed by the Department as a Utility Supervisor (Safety) in the Safety Section of the Office of Electric, Gas, & Water.

Q. Please summarize your education and work experience.

A. I graduated from Union College in 2000 with a Bachelor's degree in Civil Engineering. I received a Master's degree in Business Administration from the University at Albany. I have been employed by the Department since January 2001. I work in the Safety Section and am familiar with federal and state gas

safety pipeline codes, statewide risk-based safety performance measures, and with the operations of the major gas utilities in the state. My other duties include interfacing with utility management, working with the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) regarding interstate pipeline issues, engineering support for the Safety Section field staff, supervision of the Albany and New York City field staff, reviewing possible violations relating to 16 NYCRR Part 753 (Damage Prevention), participating in rate proceedings and negotiations, reviewing proposed pipeline designs, processing petitions and waivers relating to code compliance matters, and reviewing proposed updates to utility operations and maintenance procedures. In addition, I have contributed to and led several significant incident investigations. I have also participated in job rotations and work assignments in the Gas Rates and Gas Policy Sections, where I participated in various rate issues and in the review of utility winter gas supply planning.

Q. Mr. Stolicky, have you previously testified in any administrative proceeding?

A. Yes. I have testified in numerous rate and merger proceedings. Most recently were the Niagara Mohawk Power Corporation rate case, 12-G-0202; the Fortis, Inc. and CH Energy Group, Inc. merger case, 12-M-0192; the Consolidated Edison of New York, Inc. rate case, Case 16-G-0061; and the KeySpan Gas East Corporation d/b/a National Grid and The Brooklyn Union Company d/b/a National Grid NY rate cases, Cases 16-G-0058 and 16-G-0059. In addition, I also testified in the National Fuel Gas Corporation rate cases, Cases 04-G-1047 and 07-G-0141.

Q. Mr. Raichel, please state your business address.

A. My business address is New York State Department of Public Service, 295 Main Street, Room 1050, Buffalo, NY 14203.

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

A. I am employed by the Department as a Utility Engineer 3 in the Pipeline Safety Section of the Office of Electric, Gas, and Water.

Q. Please summarize your education and work experience.

A. I am a graduate of the State University of New York at Buffalo with a Bachelor’s Degree in Mechanical Engineering. I joined the Department in December of 1995. I have extensive knowledge of the Federal and

State gas pipeline safety codes, as well as the operations of the major gas utilities in New York State. My duties include supervising the field staff in the Buffalo office, reviewing proposed pipeline designs, reviewing proposed updates to utility operations and maintenance plans, and reviewing proposed changes to Federal and State gas pipeline safety codes. Additionally, I conduct record, field, and construction inspections of local distribution companies (LDCs) and interstate pipeline operators to ensure compliance with Federal and State gas pipeline safety regulations.

Q. Have you previously testified before the Commission?

A. Yes. I have testified in multiple gas and steam rate cases, as well as a petition of public need to construct a natural gas pipeline. Most recently I testified in the application of Dunkirk Gas Corporation for a certificate of environmental compatibility and public need to construct a natural gas pipeline, Case 14-T-0360; the rate case for New York State Electric & Gas Corporation, Case 15-G-0284; and the rate case for Rochester Gas & Electric Corporation, Case 15-G-0286.

Q. Mr. Pasinella, please state your business address.

A. My business address is New York State Department of Public Service, 3 Empire State Plaza, Albany, New York 12223-1350.

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

A. I am employed by the Department as a Utility Engineer 2 (Safety) in the Pipeline Safety Section of the Office of Electric, Gas, and Water.

Q. Please summarize your education and work experience.

A. I graduated from Clarkson University in 2009 with a Bachelor of Science degree in Civil Engineering. I have been employed by the Department since December 2010. I am familiar with Federal and State gas pipeline safety codes, as well as with the operations of major gas utilities in New York State. My duties include reviewing proposed pipeline designs, reviewing proposed updates to gas utility operations and maintenance procedures, reviewing proposed changes to Federal and State gas pipeline safety codes, and preparing citations for enforcement of probable violations relating to 16 NYCRR Part 753, New York's protection of underground facilities regulation. My other duties include conducting record, field, and construction inspections of LDCs and interstate

pipeline operators to ensure compliance with Federal and State gas pipeline safety regulations.

Q. Have you previously testified before the Commission?

A. Yes. I have testified with the gas safety panel in various rate cases, including Central Hudson Gas & Electric Corporation, Case 14-G-0319; New York State Electric & Gas Corporation, Case 15-G-0284; Rochester Gas & Electric Corporation, Case 15-G-0286; KeySpan Gas East Corporation d/b/a National Grid, Case 16-G-0058; and The Brooklyn Union Gas Company d/b/a National Grid NY, Case 16-G-0059.

Q. Mr. DiSalvo, please state your business address.

A. My business address is New York State Department of Public Service, 295 Main Street, Room 1050, Buffalo, NY 14203.

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

A. I am employed by the Department as a Utility Engineer 1 (Safety) in the Pipeline Safety Section of the Office of Electric, Gas, and Water.

Q. Please summarize your education and work experience.

A. I graduated from Clarkson University in 2010 with a Bachelor of Science degree in Civil Engineering. I have been employed by the Department since May 2012. I am familiar with Federal and State gas pipeline

safety codes, as well as with the operations of gas utilities in New York State. My duties include conducting record, field, and construction inspections of, and complaint and incident investigations involving, LDCs and intrastate and interstate pipeline operators to ensure compliance with Federal and State pipeline safety regulations. My other duties include preparing citations for enforcement of probable violations relating to 16 NYCRR Part 753, New York's protection of underground facilities regulation, reviewing proposed pipeline designs, reviewing proposed updates to gas utility operations and maintenance procedures, and reviewing proposed changes to Federal and State gas pipeline safety codes.

Q. Have you previously testified before the Commission?

A. No.

SCOPE OF TESTIMONY

Q. What is the purpose of the Gas Safety Panel's testimony in this proceeding?

A. The purpose of our testimony is to address proposals by National Fuel Gas Distribution Corporation (Distribution or the Company) for safety performance measures in the areas of infrastructure enhancement, leak management, damage prevention, emergency

1 response, and non-compliance with the pipeline safety
2 regulations. Our testimony will also address
3 integrity management, plastic fusions and
4 qualifications, inactive accounts, and annual
5 reporting requirements.
6 Q. In your testimony will you refer to, or otherwise rely
7 upon, any information obtained during the discovery
8 phase of this proceeding?
9 A. Yes, we will refer to, and have relied upon, several
10 responses to Information Requests (IRs) provided by
11 the Company. These responses are contained within
12 Exhibit__(GSP-1).
13 Q. Is the Panel presenting any other exhibits?
14 A. Yes. Exhibit__(GSP-2) provides a breakdown of the
15 high risk and other risk categories associated with 16
16 NYCRR Part 255 and 16 NYCRR Part 261.
17 **INFRASTRUCTURE ENHANCEMENT**
18 Q. What does infrastructure enhancement mean for the
19 purposes of this Panel's testimony?
20 A. By infrastructure enhancement, we mean the Company's
21 efforts to replace leak prone pipe.
22 Q. What pipe is considered leak prone?
23 A. Leak prone pipe generally includes unprotected steel,
24 cast iron, wrought iron, and some early vintages of

1 plastic pipe that can become brittle. Distribution's
2 population of leak prone pipe generally consists of
3 unprotected steel, protected bare steel, cast iron,
4 wrought iron, and some earlier vintages of plastic.
5 Q. What is meant by the term unprotected?
6 A. Unprotected means that the pipe lacks adequate
7 cathodic protection rendering it susceptible to
8 corrosion. Unprotected steel pipe often has
9 inadequate or no coating, rendering efforts to
10 cathodically protect it ineffective and uneconomical.
11 Such unprotected steel pipe is also referred to as
12 bare steel pipe.
13 Q. How do leak prone pipe replacement programs add to the
14 safety of the natural gas systems?
15 A. Leaks on underground piping can create safety risks to
16 the public and potentially lead to incidents. Removal
17 or replacement of such leak prone pipe reduces these
18 safety risks.
19 Q. Please explain the importance of removing unprotected,
20 or bare steel pipe.
21 A. Data collected by the United States Department of
22 Transportation, Office of Pipeline Safety, shows that
23 corrosion is a leading cause of leakage and that bare
24 steel pipe is the type of leak prone pipe most

susceptible to corrosion. This information is publicly available on the Office of Pipeline Safety's "Pipeline Data Mart" website at https://primis.phmsa.dot.gov/comm/FactSheets/FSCorrosion.htm.

Q. How does removing cast iron pipe add to the safety of the natural gas system?

A. In general, cast iron pipe is brittle, susceptible to graphitization, a form of corrosion, and has low beam strength. Beam strength refers to the amount of loading a structure can withstand before it fails. Cast iron pipe's low beam strength means that the material can fail if it is subjected to increased loading or a loss of ground support, which makes the material particularly susceptible to stresses from underground disturbances. Such disturbances can include, but are not limited to, ground settlement, freeze-thaw cycles, soil erosion, or nearby excavation activities. Cast iron pipe's physical characteristics make it more prone to catastrophic failure than cathodically protected steel and plastic pipe. In addition, cast iron lengths are joined by hub joints, also known as bell and spigot joints, with packing material such as jute, which is used when cast iron

pipes are first installed to prevent leakage. Unlike welded joints on steel pipe, these cast iron joints develop leaks over a period of time because they are very difficult to properly seal and join. Cast iron pipe tends to be located in densely populated areas where there are many enclosed structures and continuously paved areas. In the event of a major leak or failure, these circumstances may lead to greater volumes of below ground gas migration and expose the public to an increased risk for fires or explosions. Removing this pipe reduces the potential for leaks and incidents resulting from major leaks and failures, and improves public safety.

Q. What are other benefits associated with removing leak prone pipe?

A. Removing leak prone pipe should drive down the number of active leaks, will lead to a decline in leakage rates on the distribution systems, and also reduce overtime and operating and maintenance costs associated with responding to leak calls and monitoring leaks.

Q. Please describe the leak prone pipe replacement component of the safety performance measures being proposed.

A. This component is designed to ensure that Distribution continues to proactively remove this type of pipe from its system. Typically, the Company only proactively removes and replaces pipe, beyond the requirements of the pipeline safety regulations found in 16 NYCRR Part 255, because of significant customer complaints, or as a result of municipal or state construction projects.

Q. Does Distribution currently have a leak prone pipe removal program?

A. Yes.

Q. How does Distribution prioritize the removal of leak prone pipe?

A. The pipe to be removed from service is identified and ranked using a risk assessment model-based approach.

Q. What is a risk assessment model?

A. A risk assessment model prioritizes all segments of leak prone pipe according to attributes that pose the highest associated risk. The model has several weighted factors to determine a ranking, such as material type, diameter, pressure, date of installation, and other factors. It is important to note that the model that works for Distribution may not be appropriate for other LDCs, because each LDC has unique characteristics and geography that must be

1 considered, which prevents a uniform approach. The
2 risk-based prioritization model ranks segments of pipe
3 for removal so that the pipe that presents the
4 greatest risk to the public is removed from service
5 before lower risk pipe. This allows the Company to
6 focus resources on segments with the highest risk,
7 providing the greatest level of safety to the public.
8 Q. What current leak prone pipe replacement requirements
9 does Distribution have?
10 A. In 2016, Distribution must remove a minimum of 95
11 miles of leak prone pipe. Failure to reach this
12 minimum target will result in Distribution owing eight
13 pre-tax basis points to customers.
14 Q. For the previous two years, 2014 and 2015, how many
15 miles of leak prone pipe has Distribution removed, on
16 average?
17 A. According to DPS-73, Exhibit__(GSP-1), Distribution
18 has removed 96.7 miles of leak prone pipe on average
19 for the previous two calendar years.
20 Q. Has the Company addressed the leak prone pipe program
21 in its rate filing?
22 A. Yes. Distribution proposed to further enhance its
23 leak prone pipe removal program. The enhancements are
24 consistent with the Commission's goal of increased

leak prone pipe replacement rates for all LDCs.

Q. Please explain the proposal.

A. Distribution proposed to remove a minimum of 100 miles of leak prone pipe in 2017, 105 miles in 2018, and will continue at this rate until the remaining mileage has been replaced. Larger diameter mains, defined as 16 inches or greater, and high pressure mains, defined as operating at 125 psig or greater are excluded from this mileage proposal. The company has a separate proposal to remove a minimum of 5 miles of larger diameter and high pressure mains in 2018, and will continue at this rate until the remaining mileage has been removed. The increase in costs associated with these programs are due to the additional mileage being replaced, material costs, increased inspections, availability of contractor resources, and traceability of installed materials.

Q. Did Distribution propose an associated negative revenue adjustment for this measure?

A. No.

Q. Will leak prone services be replaced in conjunction with these newly proposed replacement programs?

A. Yes. When replacing leak prone pipe, it is common for companies to group mains and services together within

a single project. This grouping results in the most cost efficient approach towards the replacement of leak prone pipe, in addition to minimizing the time a customer is without natural gas due to the work.

Q. At this proposed replacement rate, how long will it take Distribution to replace all leak prone pipe?

A. According to the Direct Testimony of Kevin D. House, Distribution has approximately 1,897 miles of leak prone pipe and 81.3 miles of larger diameter and high pressure mains remaining within its system. At the proposed replacement rates of 105 and 5 miles per year, these programs would be completed in approximately 18 and 16 years, respectively.

Q. How does Distribution's leak prone pipe replacement program compare with that of other LDCs?

A. In terms of the remaining mileage, and overall size of the Company, Distribution has been proactive in removing leak prone pipe compared to other LDCs. We commend Distribution for its replacement efforts and for continually striving to provide a safer and more reliable system.

Q. Does the Panel agree with Distribution's proposal?

A. In part. We agree that funding should be increased so that the Company can accelerate the leak prone pipe

1 replacement program. However, we disagree with the
2 Company's proposal to remove an associated negative
3 revenue adjustment for this program. Therefore, we
4 propose that Distribution be required to replace a
5 minimum of 100 miles of leak prone pipe in 2017, and
6 110 miles each year thereafter; 105 miles of leak
7 prone pipe and 5 miles of larger diameter and high
8 pressure mains. Failure to meet the replacement level
9 in 2017 would result in a negative revenue adjustment
10 of eight pre-tax basis points owed to the customers.
11 Failure to meet the replacement levels each year
12 thereafter would result in a negative revenue
13 adjustment of six pre-tax basis points owed to the
14 customers for leak prone pipe and two pre-tax basis
15 points owed to the customers for larger diameter and
16 high pressure mains. The Commission should require
17 Distribution to replace leak prone services in
18 conjunction with the associated mains. As the Company
19 replaces the mains and services, it should also be
20 required install meters in a readily accessible
21 location, preferably located outside and protected
22 from corrosion and other damage.
23 Q. Given that Staff is testifying to a single rate year,
24 why is a multi-year approach to this program

appropriate?

A. Due to the complexity of the leak prone pipe replacement program, and in recognition that external factors may hinder Distribution's efforts in a single year, utilizing a multi-year approach allows the Company flexibility so that it can strategically manage the program more efficiently. A multi-year approach also ensures that the Company can take steps to have adequate qualified personnel available to meet the increased targets.

Q. Does the Panel support a positive revenue adjustment for exceeding the replacement targets?

A. Yes. Should Distribution exceed the leak prone pipe replacement targets, we support a positive revenue adjustment. That adjustment is further discussed by the Staff Policy Panel.

Q. How will the leak prone pipe replacement costs and associated surcharges be handled?

A. The costs and associated surcharges related to the increase in leak prone pipe replacement will be addressed by the Staff Gas Policy and Supply, and Staff Gas Rates Panels.

Q. Will the increased mileage target effect the Company's risk assessment model?

A. Not necessarily. We expect that Distribution will continue to use its risk assessment model to rank segments of pipe for replacement so that the highest risk pipe that presents the greatest risk to the public is removed prior to lower risk pipe. However, Distribution should be given the flexibility to complete opportunistic replacements, such as neighborhood approaches, or in conjunction with other entities, but overall risk reduction should still remain a driver of the replacement program. In other words, if using the neighborhood approach, areas replaced should contain high risk segments.

Q. Do you have any other recommendations regarding the removal of leak prone pipe?

A. Yes. Distribution performs inspections on newly installed pipelines to ensure that they are completed in accordance with applicable procedures and regulations. We recommend that Distribution increase onsite inspections adequate for the total leak prone pipe replacement targets to ensure that the quality of pipe going into service meets workmanship and installation standards.

Q. Are there any other conditions that Distribution should meet pertaining to your safety related recommendations?

A. Yes. We recommend that Distribution submit a quarterly report to the Secretary of the Commission detailing its leak prone pipe replacement progress. This report should include material type, mileage, project location, rank of the segment replaced at the time of replacement using the risk based model, project cost, and include a forecast of the scheduled leak prone pipe replacement projects and their rank on risk based replacement model for the upcoming quarter, at a minimum. The report should also be required to include a reconciliation of proposed replacements versus what was actually replaced. The Company should be required to submit these quarterly reports no later than thirty days after the end of the quarterly reporting periods ending March 31st, June 30th, September 30th, and December 31st.

LEAK MANAGEMENT

Q. What does the Panel mean by the term leak management?

A. Leak management refers to a utility's ability to monitor and repair existing and newly found leaks on the utility's natural gas systems.

Q. Does Distribution currently have a safety-related target for leak management?

A. Yes. Distribution has both total and repairable leak backlog targets.

Q. Is there an associated negative revenue adjustment for failure to meet these leak management targets?

A. Yes. If Distribution fails to meet either its total or repairable leak backlog targets, it owes a total of four pre-tax basis points.

Q. What is the difference between the total and repairable leak management targets?

A. Total leak management targets encompass Type 1, Type 2A, Type 2, and Type 3 leaks as defined by 16 NYCRR 255.811, 16 NYCRR 255.813, 16 NYCRR 255.815, and 16 NYCRR 255.817, respectively. Repairable leak management targets exclude Type 3 leaks because they are considered non-hazardous and are reasonably expected to remain that way.

Q. Has Distribution proposed to update or modify its leak management targets?

A. Yes. Distribution proposed to remove these leak management targets entirely. Distribution does not consider this measure reasonable, asserts that penalty mechanisms create a disincentive for improvement

1 beyond the established targets, and manages the
2 significant potential risks to its natural gas system
3 through its Distribution Integrity Management Program.
4 Q. Did the Company have any other comments related to the
5 leak management measure?
6 A. Yes. The Company asserts that this measure is
7 punitive and does not enhance safety in any way.
8 Distribution also proposes that incentives for
9 continued improvement beyond the targets should be
10 established, and the Company should have the
11 opportunity to cure shortfalls in performance prior to
12 receiving a penalty.
13 Q. For both the total and repairable leak backlogs, how
14 has the Company performed in recent years?
15 A. According to DPS-72, Exhibit__(GSP-1), Distribution
16 has demonstrated the ability to reduce its total and
17 repairable leak backlogs. For the previous five
18 years, 2011 through 2015, Distribution has decreased
19 its total and repairable backlogs on average by
20 approximately 365 and 15 leaks per year, respectively.
21 Q. How did the Company perform in 2015?
22 A. According to DPS-72, Exhibit__(GSP-1), Distribution
23 had 1,937 total leaks on backlog, two of which were
24 repairable.

Q. What does the Panel recommend?

A. Based on previous years' leak reduction averages and an increase in the leak prone pipe replacement program, we recommend maintaining fewer than 1,600 total and 25 repairable leak backlogs, at calendar year end.

Q. Do you recommend an associated negative revenue adjustment for failure to meet these backlog targets?

A. Yes. Consistent with other LDCs, we recommend that there be a separate adjustment for both the total and repairable targets. Should Distribution fail to meet its total leak backlog target, a total of four pre-tax basis points would be owed to the customers. Should Distribution fail to meet its repairable leak backlog targets a total of eight pre-tax basis points would be owed to the customers.

Q. Do you recommend an associated positive revenue adjustment for the leak management measure?

A. No. However, the Staff Policy Panel will address an incentive related to an increase in the Company's repair of Type 3 leaks.

Q. Why are these leak management targets reasonable?

A. Distribution has made moderate increases to its leak prone pipe replacement program. The Company uses both

historic and active leaks as weighted factors when prioritizing segments within its risk assessment model. Therefore, removing leak prone pipe alone should drive leak rates down. As more and more of the system includes newly installed piping, reductions in leak inventory should be easier to attain.

Q. Should either the targets or the negative revenue adjustments expire?

A. No. These targets and associated adjustments should remain in effect until changed by the Commission.

DAMAGE PREVENTION

Q. What does the Panel mean by damage prevention?

A. Damage prevention refers to the Company's ability to minimize damage to its system caused by excavation. Distribution responds to calls and performs many repairs each year caused by excavation damage to its underground facilities. Any damage to a pipeline can result in the uncontrollable release of natural gas and could lead to an incident.

Q. Please describe the performance measures related to the prevention of excavation damage.

A. In order to encourage the Company to continuously strive to improve their performance, targets for damages caused by mismarks, Company and its

contractors, and total damages per 1,000 one-call tickets were established in previous rate orders to measure Company progress in minimizing damage to their underground pipeline facilities. The total damage category includes damages caused by mismarks, those caused by Company and Company contractors, and those caused by excavator error or those where an excavator gave no notification.

Q. What is a one-call ticket?

A. The Commission's pipeline safety regulations contained in 16 NYCRR Part 753, Protection of Underground Facilities, require excavators to make a toll-free call to a one-call notification system and provide notice of their intent to perform excavation work. The one-call notification system that covers Distribution's service territory is Dig Safely NY. Dig Safely NY takes the pertinent information from the excavator and transmits it to the member utilities that may be affected by the excavation work. Those utilities then mark the location of their affected facilities so the excavator can take needed precautions to avoid damaging them. Each incoming call to Dig Safely NY will generate several outgoing notices to the member utilities such as the gas,

electric, telephone, cable, water, and sewer companies. A notice received by the utility is referred to as a one-call ticket.

Q. What is a mismark?

A. A mismark occurs when a utility fails to accurately mark the location of underground facilities in response to the one-call ticket. Consistent with the requirements of 16 NYCRR Part 753, and for the purpose of this measure, a mismark is considered any instance where the markings are off by more than two feet. It also includes any instances where the utility fails to mark facilities in response to a properly requested one-call ticket.

Q. What are damages by Company and Company contractors?

A. These are damages to Company facilities that are caused by Company personnel or by contractors that are directly working for the Company.

Q. How does prevention of excavation damage benefit public safety?

A. These damages often cause interruptions of service to customers, building evacuations, and road closures. Explosions, fires, injuries, and fatalities are less frequent, but have occurred. Therefore, reducing these types of damages improves public safety.

Q. Does Distribution currently have safety related targets associated with damage prevention?

A. Yes.

Q. Has Distribution proposed to update or modify its damage prevention targets?

A. Yes. Distribution proposed to remove these damage prevention targets in their entirety. Distribution does not consider this measure reasonable, asserts penalty mechanisms create a disincentive for improvement beyond the established targets, and manages the significant potential risks to its natural gas system through its Distribution Integrity Management Program.

Q. Did the Company have any other comments related to the damage prevention measure?

A. Yes. The Company asserts that this measure is punitive and does not enhance safety in any way. Distribution also asserts that incentives for continued improvement beyond the targets should be established as well as providing the Company with the opportunity to cure shortfalls in performance prior to receiving a penalty.

Q. Describe the Company's historical performance as it relates to damage prevention.

A. For the previous five years, 2011 through 2015, Distribution has averaged 0.44 for damages due to mismarks, 0.03 for damages due to Company and Company contractors, and 2.54 for total damages per 1,000 one-call tickets. In 2015, Distribution performed at the following levels: 0.23 for damages due to mismarks; 0.02 for damages due to Company and Company contractors; and 2.20 for total damages per 1,000 one-call tickets. The Company's historical performance is well documented in the most recent Gas Safety Performance Measures Report, filed in Case 16-G-0254, and can be obtained from the Commission's website.

Q. Please describe the Gas Safety Performance Measures Report.

A. The Gas Safety Performance Measures Report is an annual report presented by Department Staff to the Commission. The report summarizes data and analyzes performance in the areas of gas safety: damage prevention, emergency response, leak management, and non-compliance with the Pipeline Safety Regulations. It also contains data from subsets of those areas, resulting in a more thorough analysis, and is used as a tool to track and identify LDCs performances in areas widely identified as high-risk. When an LDC's

1 performance notably varies from the statewide
2 performance in a particular area, Staff generally
3 recommends that LDC institute incremental changes to
4 improve performance.
5 Q. In the latest Gas Safety Performance Measures Report,
6 was Distribution identified as an LDC in need of
7 improvement in either of the damage prevention areas?
8 A. Yes.
9 Q. In which areas of damage prevention?
10 A. In 2015, the most recent data available, Distribution
11 was identified as a poor performer in the area of
12 excavator error damages. This identification was
13 assigned to Distribution due to the sheer volume of
14 damages and overall performance in this area. In
15 2015, Distribution had a total of 133 damages due to
16 excavator error which had a subsequent ranking of
17 fourth highest in the state. In 2015, Distribution's
18 overall performance of 1.40 excavator damages per
19 1,000 one-call tickets had a subsequent ranking of
20 third highest in the state.
21 Q. What was the statewide performance level for damages
22 due to mismarks, damages due to Company and Company
23 contractors, and total damages per 1,000 one-call
24 tickets in 2015?

A. In 2015, the statewide performance level was 0.42 for damages due to mismarks, 0.09 for damages due to Company and Company contractors, and 1.87 in total per 1,000 one-call tickets.

Q. How did the Company perform in comparison to the historical statewide performance?

A. Distribution currently out performs the statewide levels for both damages due to mismarks, and Company and Company contractors. However, for the total damages area, Distribution's 2015 performance is significantly higher than the statewide average.

Q. What does the Panel recommend?

A. We recommend that Distribution be required to maintain the statewide averages of 0.42 for damages due to mismarks, 0.09 for damages due to Company and Company contractors, and 1.87 in total. In recognition of the Company's current performance as it relates to the total damage area, we recommend that a three year approach be implemented to allow the Company to progressively work towards this level. The targeted levels for the total damage area would be as follows: 2.17 in 2017, 2.02 in 2018, and 1.87 in 2019. Distribution's reporting of Company performance on these measures should be in compliance with the most

1 recent Gas Safety guidance, letter dated December 11,
2 2015, issued by the Deputy Director of the Office of
3 Electric, Gas, and Water.
4 Q. Why are these targets reasonable?
5 A. We believe that with the total volume of notifications
6 being made within the Company's service territory and
7 the inherent risk associated with excavation work,
8 public safety should be of the utmost importance and
9 is protected by these targets. In addition, as the
10 Company replaces older leak prone pipe, damages due to
11 mismarks should fall, as it is the older pipe for
12 which the Company has incomplete records, including
13 location information. This older pipe is being
14 replaced by pipe for which the Company knows the exact
15 locations, including rise and run, thus allowing the
16 Company to use updated and accurate mapping during the
17 mark-out process.
18 Q. Are damages due to mismarks, and Company and Company
19 contractors within the control of the Companies?
20 A. Yes.
21 Q. Are total damages?
22 A. Not entirely. Specifically, damages caused by
23 excavator failure to notify Dig Safely NY, sometimes
24 referred to as no-calls, and/or unsafe excavation

1 practices are not totally within the control of the
2 Company. However, the Company can minimize these
3 damages by influencing excavator activity through
4 education and outreach efforts to excavators, by
5 continuing to bill excavators for repair costs when
6 the excavator is at fault, and by referring problem
7 contractors to Department Staff for enforcement
8 purposes. In addition, Distribution should consider
9 developing best practices, in conjunction with other
10 companies affiliated with the Northeast Gas
11 Association and/or other trade associations.
12 Q. Are damages due to no-calls a component of the overall
13 damage measures?
14 A. Yes. Damages due to no-calls are simply instances
15 where the excavator fails to provide notice of intent
16 to excavate to the one-call notification system, and
17 thus no ticket is generated. This measure is part of
18 the total damages and provides an indication of the
19 general level of awareness excavators have about the
20 one-call notification system.
21 Q. How does Staff assist LDCs with their damage
22 prevention requirements?
23 A. Department Staff has been conducting an enforcement
24 program involving collection of penalties for

violations of the Commission's damage prevention regulations for approximately 18 years. In 2007, this program was expanded by having gas LDCs report all instances of damage due no-calls. Damages due to no-calls are the clearest violations of 16 NYCRR Part 753 to enforce. LDC participation takes little effort and results in greater enforcement and eventually lower damage rates to underground pipeline facilities. This joint effort has led to a significant decline in damages due to no-calls over the years, as explained in the most recent Gas Safety Performance Measures report. In addition, when promptly notified and resources are available, Staff provides aid to LDCs by working with problem excavators.

Q. Do the recommended targets for total damages per 1,000 one-call tickets include damages due to mismarks and Company and Company contractors?

A. Yes.

Q. Why do you recommend this approach?

A. This approach ensures that, even if it appears that damages due to mismarks and Company and Company contractors will not be met in a given year, the Company will still have an incentive to keep such

1 damages as low as possible because of this combined
2 total damages metric.
3 Q. Does the Panel recommend an associated negative
4 revenue adjustment for failure to achieve these
5 targets?
6 A. Yes. We recommend that Distribution be subject to a
7 negative revenue adjustment of 18 pre-tax basis
8 points, which would be owed to customers should the
9 Company fail to achieve the recommended damage
10 prevention targets. The breakdown should be as
11 follows: seven pre-tax basis points for damages due to
12 mismarks, seven for damages due to Company and Company
13 contractors, and four for total damages.
14 Q. Does the Panel support an associated positive revenue
15 adjustment for the damage prevention measure?
16 A. Yes. We support a positive revenue adjustment for the
17 damage prevention measure, which is further discussed
18 by the Staff Policy Panel.
19 Q. Should either the targets, or the negative revenue
20 adjustments expire?
21 A. No. These targets and associated adjustments should
22 remain in effect until changed by the Commission.
23

EMERGENCY RESPONSE

Q. Please describe the emergency response performance measures as followed by Distribution and other LDCs in the state.

A. These measures evaluate utility response to gas leak, odor and emergency calls generated by the public and non-Company personnel. Gas safety regulations require each gas utility to provide a monthly report of the total number of calls received and responded to in fifteen minute intervals during normal business hours, weekdays outside of normal business hours, weekends, and holidays. These measures, in addition to leak management and damage prevention, are included in the annual Gas Safety Performance Measures report. Statewide standards for the emergency response performance measures have been jointly established by Staff and LDCs within individual rate cases as follows: respond to 75% of all gas leak and odor calls within 30 minutes; respond to 90% of all gas leak and odor calls within 45 minutes; and respond to 95% of all gas leak and odor calls within 60 minutes.

Q. What is the significance of the emergency response performance measure?

A. Leaks on inside piping, improperly operated or installed appliances, and gas migration into a building from leaks on outside buried piping present risks to the general public. The utility recognizes this and dispatches personnel on a priority basis in response to calls reporting gas leaks or odors. The LDCs are required to maintain a log of such calls and track the elapsed time between dispatch and arrival times of qualified service personnel responding to the scene. As the LDC's response time lengthens, the potential for a serious incident or safety threat to the general public increases. Therefore, it is important that LDCs minimize their response times for gas leaks or odors calls.

Q. Does Distribution currently have a target for emergency response performance?

A. Yes. Distribution is required to respond to 75% of leak and odor calls within 30 minutes, 90% of leak and odor calls within 45 minutes, and 95% of leak and odor calls within 60 minutes. Failure to meet the 30, 45, or 60 minute measures results in a negative revenue adjustment owed to the customers of six, four, and two pre-tax basis points, respectively.

Q. Has Distribution proposed to update or modify its emergency response targets?

A. Yes. Distribution proposed to remove these emergency response targets in their entirety. Distribution does not consider this measure reasonable, asserts that penalty mechanisms create a disincentive for improvement beyond the established targets, and manages the significant potential risks to its natural gas system through its Distribution Integrity Management Program.

Q. Did the Company have any other comments related to the emergency response measure?

A. Yes. The Company asserts that this measure is punitive and does not enhance safety in any way. Distribution also asserts that incentives for continued improvement beyond the targets should be established as well as providing the Company with the opportunity to cure shortfalls in performance prior to receiving a penalty.

Q. How has Distribution performed in its emergency response efforts?

A. From 2011 through 2015, Distribution has exceeded the established minimum levels.

Q. What does the Panel recommend?

A. We recommend that Distribution continue to be required to respond to 75%, 90%, and 95% of all gas leak and odor calls within 30, 45, and 60 minutes, respectively.

Q. Would there be an associated negative revenue adjustment for failing to meet this measure?

A. Yes. Failure to meet either of the 30, 45, and 60 minute targets would continue to result in a negative revenue adjustment owed to customers of six, four, and two pre-tax basis points, respectively.

Q. Why are these emergency response targets reasonable?

A. As already mentioned above, shortening response times to gas leak or odor calls could reduce the potential for the development of a serious incident or safety related condition.

Q. Would the targets and associated negative revenue adjustments expire under Staff's proposal?

A. No. The targets and adjustments should remain in effect until changed by the Commission.

NON-COMPLIANCE WITH THE PIPELINE SAFETY REGULATIONS

Q. Does the Panel have any concerns with Distribution's compliance as it relates to the Commission's pipeline safety regulations?

A. Yes. We are concerned with any non-compliance of the Commission's pipeline safety rules and regulations contained in 16 NYCRR Parts 255 and 261.

Q. How are these violations identified?

A. Department Staff conducts record and field audits of Distribution on an annual basis. Staff also investigates incidents involving the Company's natural gas facilities. Typically, when Staff discovers an instance of non-compliance with the Commission's pipeline safety regulations, a compliance meeting is held with the Company detailing the code sections related to the instance of non-compliance.

Q. What is the purpose of the compliance meeting?

A. The compliance meeting is an opportunity for the Company to provide information to clarify any deficiencies found. Information clarifying these deficiencies might include providing further explanation to inquiries or providing records that were not available at the time of the audit.

Q. How long does a Company have to provide this information?

A. A Company is required to provide this information within five business days of the compliance meeting. After the five business day period, Staff reviews the

1 information and subsequently issues a formal letter
2 detailing the specifics of the violations as it
3 relates to the regulations.
4 Q. Does Distribution currently have a non-compliance
5 target?
6 A. Yes.
7 Q. Has Distribution proposed to update or modify its leak
8 management targets?
9 A. Yes. Distribution proposed to remove these non-
10 compliance targets in their entirety. Distribution
11 does not consider this measure reasonable, asserts
12 that penalty mechanisms create a disincentive for
13 improvement beyond the established targets, and
14 manages the significant potential risks to its natural
15 gas system through its Distribution Integrity
16 Management Program.
17 Q. Did the Company have any other comments related to the
18 non-compliance measure?
19 A. Yes. The Company asserts that this measure is
20 punitive and does not enhance safety in any way.
21 Distribution also asserts that incentives for
22 continued improvement beyond the targets should be
23 established as well as providing the Company with the

1 opportunity to cure shortfalls in performance prior to
2 receiving a penalty.
3 Q. What is the difference between a violation and an
4 occurrence?
5 A. Historically, audit letters outlined findings that
6 note a violation of a specific requirement, and then
7 associated it with the total number of occurrences
8 found. The term violation is commonly referred to in
9 discussions and is widely understood within the
10 pipeline industry. Thus, for the purpose of this non-
11 compliance measure, there is no difference between a
12 violation and an occurrence. These words are and can
13 be used interchangeably. Staff considers both terms
14 as an instance of non-compliance with the Commission's
15 pipeline safety regulations.
16 Q. How does the Panel account for violations in which a
17 record cannot be provided by the Company?
18 A. We will continue to consider it a standing violation
19 when any records requested by Staff during an audit
20 are either not provided or are found to be incorrect.
21 This definition of a records violation will apply to
22 situations where Distribution attempts to provide
23 missing or correct records after the five business
24 days following the compliance meeting. An official

1 Company record is the Company's only way to
2 demonstrate compliance.
3 Q. Does the Panel categorize violations?
4 A. Yes. We have two categories, which are based on the
5 likelihood of risk to public safety resulting from a
6 violation of the regulations. The two categories of
7 violations are high and other risk. High risk refers
8 to code requirements that, if not followed, lead to a
9 greater likelihood of an adverse impact on public
10 safety with regard to loss of life or property and
11 damage to the environment. A breakdown of code
12 sections by risk category is provided in
13 Exhibit__(GSP-2).
14 Q. On average, how many violations of the Commission's
15 pipeline safety regulations has Distribution been
16 cited for by Staff in the past five years, 2010
17 through 2014?
18 A. On average, from 2010 through 2014, Staff has cited
19 Distribution for 36.6 high risk and 8.4 other risk
20 violations of the minimum pipeline safety regulations.
21 Q. What were the negative revenue adjustments for
22 Distribution on its 2014 performance?
23 A. Based on the violations identified in Staff's audit
24 reports, Distribution's performance resulted in a

negative revenue adjustment of $2^{11}/_{18}$ pre-tax basis points in 2014, or approximately $148,097.

Q. How should these adjustments be utilized?

A. We recommend utilizing the above adjustments to offset costs associated with safety related programs such as, but not limited to, residential methane detection, or the odorization of gathering pipelines. We also recommend that Distribution develop a proposal for use of those funds in consultation with Department Staff, to be filed within 90 days of the Commission Order in this proceeding.

Q. Does the Panel find the Company's regulation compliance performance acceptable?

A. No. We are concerned that any number of violations can indicate a lack of the Company control, an issue with internal quality assurance, or a Company culture that is willing to accept a level of non-compliance with the regulations.

Q. What does the Panel recommend?

A. We recommend continuing the non-compliance performance measure for Distribution. For each of the first 25 high risk violations, Distribution would owe one-half of a pre-tax basis point to the customers. For each high risk violation in excess of 25, one pre-tax basis

1 point would be owed to the customers. Similarly, for
2 each of the first 25 other risk violations,
3 Distribution would owe one-ninth of a pre-tax basis
4 point to the customers. For each other risk violation
5 in excess of 25, one-third of a basis point would be
6 owed to the customers.
7 Q. Do these recommended targets differ from
8 Distribution's current targets?
9 A. Yes.
10 Q. How so?
11 A. While the pre-tax basis point adjustments for both the
12 high and other risk violations are the same, the tier
13 thresholds of 25 occurrences are different. For high
14 risk violations the threshold was 15, and for other
15 risk violations the threshold was seven.
16 Q. Why were the high and other risk threshold occurrences
17 increased in your recommendation?
18 A. The high and other risk thresholds were increased to
19 twenty-five occurrences based on consideration given
20 to the unique features of Distribution as well as to
21 maintain consistency with other LDCs.
22 Q. Does the Panel recommend any positive revenue
23 adjustments?

A. No positive revenue adjustments are recommended for this performance measure, as these audits are focused on complying with the minimum pipeline safety requirements.

Q. Does the Panel recommend capping the associated negative revenue adjustments for violations of a particular code section?

A. Yes. We recommend capping the total violation count at 10 for each of the code sections identified in Exhibit__(GSP-2).

Q. Does this mean that, if there are more than ten violations of any given code section, enforcement will not be pursued?

A. No. We consider more than 10 violations of a single code section to be gross non-compliance, for which additional action needs to be taken. Should Distribution incur more than 10 violations of a single code section the Company must file a plan for remediation explaining how it will ensure that compliance issues are addressed and resolved. This plan should include dates by which all cited violations will be brought into compliance, or, where appropriate, when remedial actions will be put in place to mitigate reoccurrence. If needed, such a

filing should be required to be made within 90 days of receiving Staff's audit letter.

Q. Should the non-compliance measure expire?

A. No. This measure should remain in effect until changed by the Commission.

Q. Why does the Panel recommend a Company remediation plan in the event that more than 10 violations of a single code section occurs?

A. First, the performance measure provides a financial disincentive for non-compliance with the Commission's pipeline safety regulations. Second, it is critical for the Commission to be able to address all violations of the pipeline safety regulations where the potential exists for serious harm or even death. As occurrences of violations can be clearly demonstrated, this measure should be automatic and avoid the need for formal, intensive penalty actions against Distribution for every occurrence of non-compliance. Note, however, that the Commission always has the authority to pursue a penalty action notwithstanding the existence of a violations measure.

Q. Please provide an example of how this violation measure would work.

A. Let us assume the field audit letter details a total of five occurrences of high risk and 20 occurrences of other risk violations. The record audit letter for that same period details a total of 30 occurrences of high risk and 40 occurrences of other risk violations. The 35 high risk violations would result in a negative revenue adjustment of $22^{1}/_{2}$ pre-tax basis points owed to the customers. The 60 other risk violations would result in an additional negative revenue adjustment of $14^{5}/_{9}$ pre-tax basis points. The resulting exposure would be $37^{1}/_{18}$ pre-tax basis points.

INTEGRITY MANAGEMENT

Q. What is an Integrity Management Program?

A. An Integrity Management Program (IM) provides the process and means to improve the safety and reliability of the natural gas system by reducing both the likelihood and consequences of incidents. These programs identify specific threats to the system, for example, excavator damage. Once identified, the next step in the IM program is to assess how these threats relate to high consequence areas. The last step in the IM program is for the operator to take action to address these threats. The resultant prevention and

1 mitigation measures taken by the operator ensure the
2 natural gas system's integrity.
3 Q. How are high consequence areas (HCAs) determined?
4 A. HCAs are determined by identifying the total number of
5 buildings intended for human occupancy and identified
6 sites within a specified Potential Impact Radius
7 (PIR). Identified sites are buildings that are hard
8 to evacuate such as hospitals, nursing homes, and day
9 care centers.
10 Q. What is the definition of a PIR?
11 A. PIR is defined as the radius of a circle, within which
12 the potential failure of a pipeline could have
13 significant impact on life or property.
14 Q. How is the PIR determined?
15 A. The PIR is determined by calculating the potential
16 failure radius associated with an identified threat.
17 The radius takes into account the maximum operating
18 pressure of the pipeline and its diameter.
19 Q. Since when have operators been required to have an IM
20 program?
21 A. Transmission pipeline operators have been required to
22 have an IM program in effect since December 17, 2004.
23 Distribution pipeline operators have been required to
24 have an IM program in effect since August 2, 2011.

1 Q. Have there been any changes to the transmission and
2 distribution IM regulations since their respective
3 effective dates?
4 A. No. However, in 2013 and 2016, the Pipeline and
5 Hazardous Materials Safety Administration (PHMSA)
6 released proposed additions to IM regulations that, if
7 approved, will require operators to apply additional
8 assessment criteria, including integrity verification,
9 to their programs.
10 Q. What does integrity verification consist of?
11 A. Integrity verification consists of four basic
12 principles: identifying higher risk locations,
13 screening segments of pipelines for categories of
14 concern, assuring adequate material and documentation,
15 and performing assessments to establish a maximum
16 allowable operating pressure.
17 Q. What is the preferred method of integrity assessment?
18 A. The preferred methods of integrity assessment are In-
19 Line Inspections (ILI) and hydrostatic pressure
20 testing. However, the hydrostatic pressure test
21 requires that the pipeline be taken out of service and
22 purged of its contents.
23 Q. What are the advantages of performing an ILI?

A. Performing an ILI allows the inspector to identify pipeline geometry deformations such as dents, identify material or construction defects, and enables the inspector to measure any wall thickness loss.

Q. Please explain what is meant by wall thickness loss.

A. Wall thickness loss occurs when a pipeline experiences either a mechanical damage or some sort of corrosion. Mechanical damage typically leaves a gouge or dent in the pipe that can be identified by ILI. Metal loss in the wall due to corrosion, either internal, external, or atmospheric, can also be identified using ILI.

Q. Has Distribution proposed any enhancements to its IM programs?

A. No.

Q. What does the Panel recommend?

A. We encourage the use of ILI within Distribution's IM programs.

Q. How does this benefit the Company's customers?

A. The completed assessments of Distribution's systems have identified several threats which, if left unrepaired, could directly impact public safety. The rehabilitation projects to mitigate these threats prolong the asset life with lower remediation costs in the future, and avoid the need for costly full pipe

1 replacement. In addition, integrity verification
2 provides for thorough review of a pipeline's safe
3 operating pressure so that maximum allowable operating
4 pressures can be justified or reset.

5 **PLASTIC FUSIONS AND QUALIFICATIONS**

6 Q. Please describe the Commission instituted Case,
7 Proceeding on Motion of the Commission to Investigate
8 the Practices of Qualifying Persons to Perform Plastic
9 Fusions on Natural Gas Facilities.
10 A. Case 14-G-0212, Proceeding on Motion of the Commission
11 to Investigate the Practices of Qualifying Persons to
12 Perform Plastic Fusions on Natural Gas Facilities, was
13 instituted by the Commission to ensure that LDCs are
14 complying with the training, testing, qualifying, and
15 requalifying procedures of persons who have performed
16 plastic fusions on natural gas facilities as required
17 by 16 NYCRR Part 255.
18 Q. Prior to the institution of this proceeding, should
19 LDCs have already been complying with the training,
20 testing, qualifying, and requalifying regulations?
21 A. Yes. These pipeline safety regulations are paramount
22 to ensuring the safety and reliability of the natural
23 gas system. Rates are set in each LDC's rate case

1 proceeding to provide funding for compliance with
2 these minimum regulations.
3 Q. Was Distribution found to be in compliance with 16
4 NYCRR Part 255 regarding plastic fusions?
5 A. No. It was discovered that, for a period of
6 approximately three years prior to Case 14-G-0212, the
7 destructive tests of the plastic fusions made during
8 qualification as required under 16 NYCRR Part 255 were
9 excluded from the qualification and re-qualification
10 of persons performing these plastic fusions. An
11 estimated 31,500 plastic fusions were performed by
12 under-qualified persons during this period.
13 Q. What actions did Distribution take to address this
14 noncompliance?
15 A. To address the noncompliance, Distribution stopped all
16 plastic fusion work until its personnel were brought
17 into compliance with the regulations. A total of 325
18 personnel underwent qualification with 1,275
19 destructive tests performed. To address the
20 noncompliance for the previous three years,
21 Distribution developed and executed a risk assessment
22 plan of the fusions performed.
23 Q. Please describe the execution of Distribution's risk
24 assessment plan.

A. Distribution's risk assessment plan consisted of targeted fusion inspections, random fusion inspections, normal course of business fusion inspections, destructive testing of fusions, and quarterly leak surveys. Distribution inspected 644 fusions and performed 129 destructive tests, all of which passed. Leak surveys of over 763 miles were conducted to address the risk from the period of noncompliance.

Q. How would you describe Distribution's performance in addressing the noncompliance?

A. Distribution took immediate action to address the noncompliance, fully assessed the risk posed by the noncompliance, took timely actions to mitigate possible risk during its assessment, and promptly eliminated or remediated every noncompliant plastic fusion found. To highlight Distribution's commitment to addressing the noncompliance, we note that 316 inspections and 83 destructive tests of the inspections and tests performed were a result of Distribution following up on the results of one targeted fusion inspection.

Q. Has Distribution addressed plastic fusions and qualifications within its filing?

A. Yes. Distribution has implemented new procedures to inspect electro-fusion joints, on new construction, with a second qualified individual, and was ordered to document the location and inspection of all plastic fusions in an electronic database.

Q. What does the Panel recommend?

A. We support Distribution's new procedures and the use of an electronic database. However, we recommend that Distribution be prohibited from recovering any costs associated with Case 14-G-0212 from ratepayers and that any such costs be normalized out of the historical period. Because of the expectation that Distribution would comply with the pipeline safety regulations prior to placing facilities into service, any remediation work to these facilities should be considered a duplication of effort, and therefore should not be the responsibility of ratepayers. Distribution is required to track these associated remediation costs until such time that all remediation efforts have been completed as a directive under Case 14-G-0212. Distribution is also required to document the inspection of all exposed fusions of new construction, as well as normal operation and maintenance activities. Currently, Distribution

provides monthly updates of its fusion inspections. We recommend that Distribution cease the monthly updates and provide an annual update, commencing in 2017, by January 15th of each calendar year.

INACTIVE ACCOUNTS

Q. Has Distribution addressed inactive accounts within its filing?

A. No.

Q. How many inactive accounts does Distribution have?

A. According to DPS-70, Exhibit__(GSP-1), and as of June 21, 2016, Distribution has 21 inactive accounts on record. The length of time these accounts have been left inactive for ranges up to 45 days.

Q. Why do some accounts remain inactive for longer periods of time?

A. Reasons for accounts remaining inactive for longer periods of time include the Company's inability to gain access, the accounts being referred to field operations for physical disconnection, and the legal replevin process utilized to secure access.

Q. Should all meters and service regulators be installed in a readily accessible location?

A. Yes. All meters and services are required to be installed in a readily accessible location and be

protected from corrosion and other damage, including any vehicular damage that may be anticipated.

Q. Is there any usage associated with inactive accounts?

A. Yes. According to DPS-70, Exhibit__(GSP-1), approximately 222 Ccf of usage was recorded by the Company as an operational expense.

Q. What do the pipeline safety regulations say with regard to the abandonment or inactivation of facilities?

A. The Commission's regulations, 16 NYCRR 255.727(d), states that "[w]henever service to a customer is discontinued, one of the following apply: (1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. (2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly. (3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed."

Q. Is there a timing requirement to commence the abandonment or deactivation of a facility?

A. While not explicitly defined within the pipeline safety regulations, it is important to note that the pipeline safety regulations do not recognize an active service without a customer, and it is a requirement to commence this process as soon as practicable. The regulations do require that each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service and specifically require action to take place when service to a customer is discontinued.

Q. What does the Panel recommend?

A. While we are supportive of the efforts taken thus far by the Company, we recommend that all meters and services are required to be installed in a readily accessible location and be protected from corrosion and other damage, including any vehicular damage that may be anticipated.

ANNUAL REPORTING REQUIREMENTS

Q. Are there any other conditions that Distribution should be required to meet pertaining to your safety related performance measure recommendations?

A. Yes. We recommend that the Company submit a report on its performance meeting these measures within 60 days following the end of each calendar year. Any

1 modifications made to the submitted data as identified
2 in Case 13-M-0314, an Operational Audit Titled "Issue
3 a Request for Proposal for an Independent Third-Party
4 Consultant to Conduct a Review of the Accuracy and
5 Effectiveness of Certain Reliability and Customer
6 Service Systems at all Gas and Combination Gas and
7 Electric Utilities in New York State that Provide
8 Statistics to the Commission on the Services They
9 Provide Customers," should also be required to be
10 incorporated into these measures.
11 Q. Please discuss Case 13-M-0314.
12 A. Case 13-M-0314 is a focused operations audit of nine
13 LDCs by an independent consultant. The objectives of
14 this audit were to assess the completeness and
15 accuracy of the performance measure data for emergency
16 response times, leak management, and damage prevention
17 as submitted, to assess the comparability amongst
18 utilities, and to determine the suitability of the
19 measures. Distribution participated in this audit and
20 its recommendations were made public at the April 20,
21 2016 Commission Session.
22 Q. Does this complete the Panel's testimony?
23 A. Yes, at this time.

A.L.J. LECAKES: Any exhibits?

MR. FAVREAU: Yes, sir.

BY MR. FAVREAU: (Cont'g.)

Q. Did you prepare any exhibits that accompany your testimony?

A. Yes.

Q. Are the documents identified as Exhibits GSP1 and 2 those exhibits?

A. Yes.

Q. Did you make any changes or corrections to those exhibits?

A. No.

MR. FAVREAU: Your Honor, I'd like to mark those exhibits for identification.

A.L.J. LECAKES: GSP1 will be 192 and GSP2 will be 193.

MR. FAVREAU: I think with that this panel is ready for cross examination, Your Honor.

A.L.J. LECAKES: Okay. Company, do you have cross for this panel?

MR. MILLER: We do, Your Honor.

A.L.J. LECAKES: Proceed.

MR. MILLER: Preliminary matter, Your Honor.

CROSS EXAMINATION

BY MR. MILLER:

Q. Panel --

MR. MILLER: May I approach the Panel?

A.L.J. LECAKES: Yes, absolutely.

MR. MILLER: The Panel was offering corrected testimony. I showed them Exhibit -- it's a -- Exhibit KDH14 which was marked as Exhibit 191. It's a response by Staff -- this Staff Panel to company interrogatory and I bring their attention to the response where they note that the Staff testimony should be corrected. The reference was page 49. I don't know if that's the correct reference in the corrected testimony. I think it might be 51 now.

MR. FAVREAU: And Mr. Miller, just to -- I know we spoke about this earlier, I'm being told that would was changed to the word could so the -- the testimony that is corrected is -- it uses the word could.

MR. MILLER: This one is corrected now to say could?

MR. FAVREAU: Yes, correct.

MR. MILLER: That's fine.

A. (Stolicky) Yes.

BY MR. MILLER: (Cont'g.)

Q. Thank you. Okay and with that we can start. Page 16, line 3, of your testimony, will you turn to that? That's your discussion of leak prone pipe. Tell me when you're ready. Ready?

A. Yes.

Q. Now you talk about a -- for 2017 you would have a -- a safety metric requiring a minimum of 100 miles replacement of leak prone pipe. Is that correct?

A. Yes.

Q. And then in 2018 and years thereafter you would increase that to 105 miles of leak prone pipe and 5 miles of large diameter and high pressure leak prone pipe. Correct?

A. Yes.

Q. Okay. And you propose an 8 basis point penalty for failure to meet the 100 mile target in 2017. Is that correct?

A. No.

Q. Okay. What -- tell me what your proposal is for 2017?

A. We proposed a 9 pre-tax basis point negative rather than assessments.

Q. You're quibbling with the term penalty.

A. Nowhere do we recommend a penalty for NFG.

Q. Okay. So you're saying negative -- tell me what you said Mr. Stolicky.

A. Negative revenue adjustment.

Q. Okay. And how would -- how would that be undertaken -- a negative revenue adjustment, would that come out of earnings?

A. I'd have to defer to the Gas Rates Panel as to how that would be calculated -- either the Gas Rates or Accounting Panel.

Q. You're deferring it to a different panel?

A. Correct.

Q. So you'd feel more comfortable if I call this a negative revenue adjustment in my cross rather than a penalty?

A. Yes.

Q. Okay. So is it true also that you propose a penalty of 6 -- sorry -- a negative revenue adjustment of 6 basis points for failure to meet the 105 mile target in 2018?

A. Yes.

Q. And 2 basis points for the large

diameter. Is that correct?

A. Correct.

Q. In the -- the incremental 10 miles in years 2018 and beyond is composed of 5 miles of normal leak prone pipe and 5 miles of large diameter high pressure pipe. Correct?

A. (Pasinella) Can you repeat that please?

Q. So the -- the 110 miles in 2018, is that -- and that is composed of 105 miles of normal leak prone pipe and then an additional 5 miles of high pressure or large diameter. Correct?

A. (Stolicky) Correct.

Q. Was it for the calendar year 2018?

A. Yes, all -- all gas safety performance measures are -- are measured on a calendar year.

Q. The rate year in this case ends March 31, 2018. Is that correct?

A. Subject to check, yes.

Q. Okay. Do you know if there's any mechanism for National Fuel to recover the return requirement on leak prone pipe installed after this rate year ends?

A. I'm not sure we can answer that

question. Can you repeat it again?

Q. Yes. Do you know if there's any rate mechanism, right? Do you know if there's any rate mechanism for the company to recover the cost of leak prone pipe replacement after the current rate year ends?

A. Can you point to us in our testimony where we covered that?

Q. You don't. I'm just asking you.

A. Then we cannot answer that question.

Q. Okay. Do you have any idea what the approximate investment would be for the 110 miles of leak prone pipe you recommend be installed in 2018?

A. No.

Q. Are you aware of the cost of leak prone pipe replacement per mile and when I refer to that I'm referring to the -- the average leak prone pipe not the high pressure or large diameter.

A. I'm aware of what Witness House put in his rebuttal testimony.

Q. What number does he use?

A. On page 49, lines 1 to 5, there's actual -- there's actual policy. The chart refers to actuals for fiscal year 2014, fiscal year 2015, and fiscal year 2016 forecast which -- these are total spending for

main and service replacement costs. So we -- we could do that math based on Witness House's cross earlier with the leak prone pipe replaced.

Q. But you're not aware of the projected cost of leak prone pipe replacement per mile are you?

A. No.

Q. Okay. Is large diameter, high pressure leak prone pipe more expensive than the regular run of leak prone pipe replacement?

A. According to Witness House, yes.

Q. Do you have any independent knowledge of that?

A. No.

Q. You didn't look at those numbers?

A. No.

Q. So you wouldn't know for example that leak prone -- that the high pressure, large diameter leak prone pipe is about three times more expensive to do than the regular leak prone pipe?

A. Without seeing the numbers, no.

Q. Okay. Is it your testimony that you're not aware that in 2018 there is no rate mechanism for the company to recover its investment on leak prone pipe replacement?

A. Correct.

Q. And is it your testimony that you would apply a negative revenue adjustment to the company irrespective of whether it could recover its revenue investment on that leak prone pipe?

A. Yes.

Q. Can you explain why?

A. I think the -- the best way the Safety Panel can answer this is that we worked with other panels to develop the target area replacement level and there is another group that went through the capital budget to provide adequate funding to meet that replacement level. It probably doesn't answer your question, but it's -- we didn't recommend dollars.

Q. Okay. We can leave it. Let's go to leak back logs. Was it your testimony that the company should incur a negative revenue adjustment if it fails to maintain fewer than 1600 total and 25 repairable backlogs at calendar year end?

A. For the calendar year 2017, correct. That would be -- could you say what page number in the testimony you're on?

Q. It's page 24 of the redline testimony.

MR. FAVREAU: Is that the same page

number on the -- it should be the same page number before roughly. I mean you're going to have to check to see if these are different.

A. We're in that section.

BY MR. MILLER: (Cont'g.)

Q. Well, the pages may be different, but the net revenue adjustment mechanism doesn't differ.

A. I'm just trying to follow you.

Q. Let me know when you're ready, Mr. Stolicky.

A. The panel is ready.

Q. Okay. So relief backlog target, are you -- is your proposal if the company fails to meet it a four basis point adjustment?

A. Which leak backlog target?

Q. 1600.

A. Correct.

Q. Okay. And then you talk about a repairable leak backlog target. Correct? I'm just trying to get a sense of how this works.

A. Correct.

Q. Okay. So leak backlog target 8 basis points or is it just another 4 basis points for a total of 8 basis points for the -- the leak backlog mechanism?

A. There -- there are two leak backlog targets, each one is worth 4 basis points.

Q. Okay.

A. (Pasinella) 4 and 8.

A. (Stolicky) Scratch that. That's incorrect. One is 4 basis points. One is 8 basis points. I would point to the testimony, page 24 lines 11 through 16.

Q. So how many basis points for the 1600 leak backlogs?

A. 4 basis points.

Q. And how many for the repairable leaks?

A. 8 basis points.

Q. 8 basis points for repairable. So is it -- does that add up to 12 for the total metric?

A. Yes.

Q. Okay. I was just confused. I'm not trying to be cute. And the repairable leak backlog is 25. Is that correct?

A. Yes.

Q. Can you point me to where in the regulations at part 255 or any other part of the safety code where an appropriate number of leak backlogs is specified?

MR. FAVREAU: Objection, Your Honor. The regulations speak for themselves. I mean these aren't -- these are factual, technical witnesses.

A.L.J. LECAKES: Overruled. It's their -- it's their job to know those regulations and to enforce them. You can answer the question.

A. I think there's -- I think there's two answers to your question.

BY MR. MILLER: (Cont'g.)

Q. Okay. There was one --

A.L.J. LECAKES: Hopefully they're consistent.

Q. -- question. Go ahead.

A. As those of us that are familiar with the pipeline safety regulations, there -- there are areas where -- there are requirements, but those requirements leave some -- states a framework for the operator to follow and then the operator has to come up with the way to run its operations within the framework. So I'm going to say the first answer is there is not a leak backlog target in the pipeline safety regulations, but the second part of that is there are regulations that cover situations where if you have frost conditions in the ground, particularly with cast-iron pipe, there's --

there's -- there's a risk that is explained in the regulations that there is a greater risk of migration and therefore greater hazard.

And to go back to the pipeline safety measures as to why we have a leak backlog target and as explained in the testimony, there's a greater risk of gas migration in the frost conditions which is why the leak backlog is targeted within the dichotomy there. The lower number of leaks, the less issues we have with migration and the more -- greater level of public safety we have so you have the premise outlined in every direction.

BY MR. MILLER: (Cont'g.)

Q. Would you agree that I -- there's no -- that I could not go to the regulations and find a formula or a specification that would show that National Fuel should have a backlog of 1600 leaks?

A. Correct.

Q. And same question for 25 repairable leaks, would you also agree that there's nothing in the regulation that I can go to that would specify that 25 is the appropriate number for National Fuel as a backlog?

A. Correct.

Q. So based on the Panel's last answer, I assume that you believe that setting ever lower leak

backlog targets is a good thing?

A. We believe that minimizing no leaks going into the frost season is a benefit to public safety.

Q. Now would you accept, subject to check unless you have it up there with you, it's also an exhibit in Mr. House's testimony that year 2015 Gas Safety Report indicates that National Fuel had a backlog of 2,066 leaks?

A. For which calendar year?

Q. It's in your report. I don't -- I would imagine it's calendar years, but your report listed it as 2015. It's in one of your appendices.

A. Okay. Yes, that -- that is the data as reported by NFG.

Q. And your proposal is that the company incurred a negative revenue adjustment unless it reduces that backlog to 1600 leaks in 2017. Correct?

A. I would like to point you to page 23, line 22 of our testimony, it refers to an IR response by the company where the leak backlog was 1,937 total leaks.

Q. Do you know why there would be a discrepancy between that number and your 2015 Gas Safety Report?

A. They're both data reported by the company. I would have to ask the company for the

difference.

Q. So that's an even lower number than was indicated in your 2015 report then. Correct?

A. Correct.

Q. Do you know if there is money allocated in Staff's revenue requirement to reduce that leak backlog down to 1600?

A. No, I -- I do know that -- that we -- we looked at the history of the -- the client and the leak backlog over the years and just to -- what -- just for simple math's sake, we averaged 365 leak reduction each year for 5 years. If -- if that was the case, you would have been at 1,207. Well, we took into consideration that that may not be the normal trend and so based on our -- our experience with -- with the company operations and -- and just through the normal course of business with replacing an accelerated amount of leak prone pipe, the normal leaks you discover on an annual basis, 1600 was a very reasonable recommendation.

Q. Let's talk about that. Let's -- was National Fuel under a gas safety mechanism put in place pursuant to case 13-G-0136?

A. Yes.

Q. Okay. And that -- that was in place

for the years -- calendar years 2014 and 2015 and beyond. Correct?

A. Correct.

Q. Okay. Would you accept that the leak backlog target in 2014 was 3,860?

A. Subject to check.

Q. Okay. And what does your 2015 safety report show National Fuel's actual backlog was in 2014?

A. 3,053.

Q. There was roughly 800 leaks under the target. Correct?

A. Correct.

Q. Do you know the backlog target in 2015? Was it 3500 total leaks?

A. Subject to check.

Q. And based on the discussion we had, National Fuel reduced that to under 2,000 leaks. Isn't that correct?

A. Correct.

Q. Of the leak backlog, how many were repairable leaks?

A. (Raichel) For clarification, what backlog are we talking about?

Q. 2015.

A. 2015.

Q. Yes.

A. (Stolicky) As reported by the company, zero.

Q. Okay. If there were no repairable leaks, doesn't that mean that all of the leaks in 2015 were type 3 leaks in the leak backlog?

A. Correct.

Q. Did the regulations under part 255 require that type 3 leaks be repaired?

A. This goes back to the two prong answer we discussed earlier. The classification of a type 3 leak is by definition nonhazardous in the regulations and has to be monitored annually; however, if a company is carrying leaks on their system, you run into the concerns and situations where you have odor calls from the public to respond to nonhazardous leaks, the company is spending a lot of money on public awareness to have people call in gas leaks when -- if they smell a gas leak, and if the company responds as they do as Witness House pointed out in his testimony very efficiently, you're spending money to respond to what is a nonhazardous leak, but then if you don't repair it, it runs counter to your public awareness program that you just spent a lot of money on to educate

the public to have them call in the leak. So the framework is -- is included in the regulations to say yes, you should be repairing these leaks. By definition a type 3 leak classification, they're -- they're nonhazardous.

A. (Raichel) The other issue with type 3 leaks as Mr. House testified earlier and I think everybody is aware it kind of gets cold in Buffalo, at such time that the company does implement their frost plan, we also have to -- the company also then has to -- has an increased cost of going ahead and putting those type 3 leaks out for additional surveillance or evaluation based upon the frost conditions which also fits into the framework of they may not be repairable by definition, but as Witness House says many times in his testimony that they approach the operations of their system and their distribution targeting management -- so the company has recognized that they're at an accelerated risk to clearing type 3 leaks which is why they go out and -- and do what we call frost surveys. They do a leak survey in frost conditions because there is known leak threat.

Q. Do you agree that type 3 leaks don't have to be repaired under the code?

A. Correct.

A. (Stolicky) Based on a previous

description, our answer is no.

Q. So is it your testimony that part 255 requires the company to repair a type 3 leak?

MR. FAVREAU: I believe with this witness that I believe you've asked this question a few different ways. I think it's already been answered.

A.L.J. LECAKES: Actually I -- I appreciate the clarification at this point because it's got me confused. This is the most direct question that I think has been asked in the last few so.

A. I have -- I have to go back to the two prong answer. The code does not require -- I'm sorry. The code does not have a timeframe for the repairing of type 3 leaks, but the framework is there because of the elevated public awareness issues, nuisance issues, and added expense to the company on top of the fact that if it's responding to a type 3 leak, those resources are not available to respond to a real emergency. The framework is there to show that the leaks should be repaired.

A.L.J. LECAKES: Mr. Miller, I -- I understand your line of questioning at this point. I understand the witness's answers as they are so if you want to move on to a difference subject, I'd appreciate it.

MR. MILLER: That's fine. I think that -- I think the parts I've picked aside can stand for itself.

A.L.J. LECAKES: I -- yeah, I agree.

BY MR. MILLER: (Cont'g.)

Q. Did members of this Panel testify in the Kedley and Kedney [phonetic] cases 16-G-058 and 059?

A. Yes.

Q. Do you agree that for Kedney, you recommended that beginning in 2017 the backlog of total leaks be reduced by 150 leaks per year?

A. (Pasinella) Which company was that again?

Q. Brooklyn Union.

A. (Stolicky) Without having the testimony, it's subject to check.

Q. Do you know what baseline for total leaks you were recommending for Kedney in 2017? Was it 3650?

A. I -- I do not have that case memorized. I would have to go back and look.

Q. How about for Kedley? Do you recall that you recommended that their number of leaks be reduced by 750 per year?

A. That's the same answer subject to check.

Q. And do you recall that their total leak backlog was 10,700?

A. Same answer subject to check.

Q. Okay. We can move on now to excavator damages.

MR. MILLER: I apologize Your Honor, but we prepared the cross on the old testimony before the new one was -- I just want to --

A.L.J. LECAKES: I -- I understand. I've had trouble following it myself because I have a couple of different copies.

MR. STOLICKY: I have a copy of the old one.

A.L.J. LECAKES: You have the old one? It's 29 on the old one, but I don't think that helps the record very much. What I'm -- what I'm looking here is that 3-year approach that you're recommending to work toward targeted levels for total damage.

MR. MILLER: On the initial pre-filed testimony, it's page 29 beginning of lines 13 and continuing to the bottom of the page.

MR. STOLICKY: It's 31 and 32 I'm told

on the new testimony.

MR. MILLER: Okay.

BY MR. MILLER: (Cont'g.)

Q. Let me know when you have that Panel. Are you ready?

A. (Stolicky) Ready.

Q. Okay. Tell me if I'm -- if I'm understanding this right. You're recommending a 3 year approach to allow the company to progressively work toward targeted levels for total damages that would be as follows: 2.17 in 2017, 2.02 in 2018, and 1.87 in 2019. Is that correct?

A. (Pasinella) That's correct.

Q. Now would you please refer to page 35 of the 2015 Gas Safety Report? Would you agree with me that National Fuel's damages due to company and company contractor error per 1,000 tickets of 0.02 is among the lowest in the state?

A. That's correct.

Q. And on page 33 of that report, would you also agree that National Fuel's damages due to mismarks per 1,000 tickets of 0.23 is among the lowest in the state and would be lowest if you eliminated Corning in St. Lawrence?

A. (Stolicky) Yes.

A. (Pasinella) I would agree.

Q. Okay. Now the numbers that we discussed earlier for purposes of your net revenue adjustment is for total damages. Correct?

A. That's correct.

Q. In total --.

A. (Stolicky) Just to clarify, are you talking about the negative revenue adjustments?

Q. Yes.

A. Because there are 3 different targets and 3 different negative revenue adjustments.

Q. Okay. I'm looking at total damages right now.

A. Okay.

Q. Okay? So total damages is composed of 3 elements, right, the two that we just discussed, the mismarks and the company and company contractor, and there's a third element is there not?

A. There is a third and a fourth.

Q. And what was the third and the fourth, Mr. Stolicky, because I know one is third party excavators --

A. Correct.

Q. -- what's the fourth?

A. The fourth one would be damages to no calls.

Q. Due to no calls. Okay. Now those two categories that you mentioned, the third party excavators and damages due to no calls, would you agree that they're largely outside the control of the company?

A. I would refer you to the testimony page 32.

Q. Uh-huh.

A. Lines 12 through page 33, line 11.

Q. Okay. Now can you answer the question?

A. I -- I --.

Q. Would you agree that those are --?

A. I believe the Panel has already testified to that.

Q. Okay. So if you look at page 33 of your testimony and you -- you admit, do you not, that the total damages are not entirely within the control of the company. Correct?

A. Page 32, line 13, yes.

Q. I'm sorry. Did you answer the question? Okay. So when you said the company can

minimize third party damages by influencing excavator activity through several different things. Correct?

A. Yes.

Q. So the first is education and outreach efforts to excavators, does the company have an outreach and education program for excavators?

A. Did the company ask this in an IR?

Q. Okay.

A. I believe the company asked this question to Staff in an IR.

A.L.J. LECAKES: That doesn't answer the -- the question asked by counsel. Do you want to ask the question again?

Q. Does -- does National Fuel have an outreach and education program to excavators?

A. We are aware the company has a public awareness program. Under that program, there should be a portion targeting the excavation community.

Q. Does the company bill excavators for repair costs when the excavator is at fault?

A. Yes.

Q. Does company refer problem excavators to the DPS for enforcement?

A. We -- we do receive --.

A. (Pasinella) Yes.

A. (Stolicky) We do receive reports. We don't know if it's all -- all of them, but we do receive reports from the company.

Q. In -- in terms of excavator or third party damages, can you point to any regulations that the company is not complying with?

A. Is your question do we know of any regulation?

Q. Yes.

MR. FAVREAU: I object to it. It's an overbroad question. Do you mean specifically for gas leak or any regulation or any commission regulation?

MR. MILLER: No, I limited it, Mr. Favreau, to the regulations concerning relations with the third party excavators.

MR. FAVREAU: Okay. I just -- I didn't hear that part if you did. That's all.

MR. MILLER: That's fine.

A. If the company has reason to believe that the integrity of their pipeline can be damaged through excavation activities, they are required to monitor that situation as frequently as necessary to avoid damage. If there is a problem excavator out there and

that problem excavator is repeatedly damaging the NFG distribution system then you would not be in compliance with 255.614B.

BY MR. MILLER: (Cont'g.)

Q. And to the best of your knowledge, is that the case?

A. We have not issued a violation for that code section.

Q. Is the company already subject to penalties for violations of damage prevention regulations in 16NYCR753?

A. Yes.

Q. Okay. Let's move on to emergency response time. Okay. Page 37 of the revised copy -- red line revised. Do you have that?

A. Okay.

Q. Okay. You state that statewide standards for emergency response performance measures have been jointly established by Staff and LBCs within individual rate cases as follows and then you list them: 75% of all leak and odor calls within 30 minutes response, 90% within 45 minutes, and 95% within 60 minutes. Correct? Do you see that?

A. Yes.

Q. Can you point me to one such individual rate case that was not a settlement where these standards were jointly derived?

A. Is that possible?

Q. Is it your -- is it your understanding --?

A. If there's a litigated case, I'm not sure how anything can be jointly agreed upon.

Q. So these came from settlements, is that right?

A. These came from discussion with Staff and all the major LBCs in the state as to the standard measurement and the reporting criteria going back to 2003.

Q. Well, but doesn't your testimony say they were established within individual rate cases?

A. Yes.

Q. Okay. And we agreed that those were more than likely settlements?

A. The criteria behind the gas safety performance measures are from the criteria jointly developed with Staff and the companies.

Q. And when was that?

A. So for -- for consistency sake we used that criteria as to how we measure the targets in the rate

cases.

Q. When were they jointly developed?

A. 2003.

Q. Where?

A. Here.

Q. In a collaborative?

A. Yes, it was -- it was a collaborative effort. Was it a commission collaborative? No.

Q. They're not in the regulations are they?

A. Yes.

Q. For reporting purposes, they are. Correct?

A. These -- these targets and the reporting purposes are in the regulations.

Q. But if a company fails to meet that target, it's not in violation of the regulation is it? It's simply a reporting requirement in the regulation.

A. The measurement itself is just a reporting requirement.

Q. Okay. You're aware that generally joint proposals aren't to be used as precedent?

MR. FAVREAU: Objection.

A.L.J. LECAKES: Sustained. No

necessary.

MR. MILLER: That's fine. You got one.

A. If that's on the record, please strike that.

MR. MILLER: That's a well-trained witness, John.

Q. We're still on the subject. Turn to your 2015 Gas Safety Report for the emergency response times. Do you have that?

A. (Pasinella) Which target are you referring to: the 30 minutes, the 45 minute, or the 60 minute?

Q. The 2015 Gas Safety Report.

A. Yes.

Q. Right. I don't see the 30 minute response there. Is there a reason why that was omitted?

A. It was not omitted. It's on page 21 and 22 in the body of the actual report.

Q. So it's just not in one of the appendices. Is that what you're saying?

A. Correct.

Q. Okay.

A.L.J. LECAKES: Is the 2015 Gas

Safety Report on DMM -- is it under -- I think, Mr. Miller, you said it was under the previous case number 13G --.

MR. MILLER: No, Your Honor, the 2015 Gas Safety Report is in case 16-G-O254 --

A.L.J. LECAKES: Okay.

MR. MILLER: -- and it's one of Mr. House's exhibits as well I believe.

A.L.J. LECAKES: Okay. Great. Thank you.

MR. MILLER: And it is under DMM.

BY MR. MILLER: (Cont'g.)

Q. Okay. Let me move onto your NRA for violations of regulations. It's also KDH12 which I believe is Exhibit 189.

A.L.J. LECAKES: Great. Thank you very much.

BY MR. MILLER: (Cont'g.)

Q. So the Panel is also proposing an NRA for violations of regulations. Correct?

A. (Stolicky) Correct.

Q. And violations for all of the LDCs are shown on Appendices G and H of the 2015 Safety report. Are they not?

A. Correct.

Q. In the category that you list as high-risk safety violations, is there any company that had no such violations shown on Appendix G?

A. There are no companies with zero violations in a calendar year.

Q. And in fact, some companies had an excess of 100 violations in any year. Correct?

A. Correct.

Q. What does the term OHQ stand for on the -- on Appendix G of that report?

A. Operating headquarters.

Q. Okay. And staying on that page, the 2015 Gas Safety Report shows that National Fuel has 9 OHQs. Correct?

A. Correct.

Q. And -- well, National Grid New York has 2. Correct?

A. Correct.

Q. Now, your response to NFG DPS134 states that when Staff conducts record and field audits for utilities, it takes into consideration the operating headquarters found within an LDC. Is that correct?

A. What was the RN number again?

Q. 134. Do you have it?

A. I have it. We have it.

A.L.J. LECAKES: Thank you.

MR. FAVREAU: Is this what we're doing tomorrow as an exhibit?

MR. NICKSON: Your Honor, it's part of the group exhibit.

A.L.J. LECAKES: Okay. And that would be marked later -- probably tomorrow.

A. All right. Now that we all have it, can you repeat the question please?

BY MR. MILLER: (Cont'g.)

Q. Yeah. Your response states that when staff conducts record and field audits for utilities, it takes into consideration the operating headquarters found within an LDC. Correct?

A. And can you point out where we say that? The staff conducts record and field audits annually for each operating headquarter found within an LDC.

Q. Okay. Are you saying that you do take that into consideration the number of OHQs?

A. Each OHQ is a stand-alone audit.

Q. Okay. So this -- let me test that a little bit. So I'd like you to consider two identical

companies and we can actually use two here, one with 9 like NFG has and one with 2 like KEDNY has. Okay?

A. I -- I guess I need to understand how -- how you're comparing yourself to another company?

Q. I'm just -- I just want to go through this exercise with you and just -- because if you look at your response to 134 that we were just talking about. You talk about the sample sizes you use. Correct?

A. Correct.

Q. And you say that sample sizes are selected so the audit results have a 95% confidence level with 15% confidence interval. Do you see that?

A. Yes.

Q. That would determine the samples that you would audit. Correct?

A. Right.

Q. The sample -- and it would determine --

A. Sample size.

Q. -- the sample size. Right?

A. Correct.

Q. Okay. So if you had two companies that each had -- that were virtually the same except one had 9 OHQs and one had 2. I'd like you to just go down

this little path with me. Assume that they have 4500 repaired leaks each so that one company -- the company that has 2 operating centers if they had 45 -- each had 4500 repaired leaks, the company that has only 2 operating centers would have 2250 leaks for each operating center. Correct? With me so far?

A. I -- the math doesn't work that way.

Q. Hypothetical. Okay?

A. Hypothetically.

Q. Hypothetically. The same company with 9 operating centers, right, would have 500 leaks each hypothetically for your sample size. Right?

A. Hypothetically.

Q. Hypothetically. So when Staff calculates a statistical sample, right, using that 95% confidence level with a 15% confidence interval, what you're essentially doing is plugging that into a statistical calculator, right, to get the amount -- the sample size for each of those OHQs. Correct?

A. Yes.

Q. Okay.

A. Hypothetically.

Q. So hypothetically would you agree that with only two operating locations, you'd only need 84

samples -- 42 in each OHQ to reach the 95% confidence level with the 15% confidence interval if you plug those numbers into the statistical calculator?

A. If this is part of a hypothetical example, I'll say yes. Otherwise, if you're asking for the actual number it would be subject to check.

Q. Okay. Now if you did the same analysis for the company that had the 9 operating centers, right, and you had to plug those numbers into the calculator, wouldn't you need 351 samples -- 39 in each operating headquarters or OHQ to reach the same 95% confidence level at a 15% interval?

A. This is your example?

Q. Yes.

A. Yes.

Q. Now if you assume that each company had a 2% error rate, all right, for noncompliance, the company that only had 2 OHQs would have less than 2 non-compliances on the 84 samples, correct, at 2%?

A. Correct.

Q. And yet, the company with the 9 OHQs would have over 7 on the same 2% error rate?

A. Correct.

Q. Now in -- is it true that Staff's 2015

report in fact tried to normalize for the number of OHQs and I refer you to Figure 12 in that report? Figure 12 is on -- I just have the exhibit. If you have Mr. House's exhibit, it's page 36. It's Figure 12 in the report.

MR. FAVREAU: What's the title on it please?

MR. MILLER: It's the 2015 --

MR. FAVREAU: No, no, no, the title of the graphic.

MR. MILLER: Non-compliances Identified Through Audit Process 2010 --

MR. FAVREAU: Thank you. Okay. We got it. Thank you.

A. On the previous page, so page 28 the bottom paragraph, it describes how the calculation was performed. The data was normalized by the number of OHQs.

BY MR. MILLER: (Cont'g.)

Q. Right. And doesn't that table -- Table 12 -- indicate quite clearly that National Fuel by far has the lowest non-compliance rate in the state when it's normalized for OHQs?

A. It does have shorter bars than the other companies.

Q. And is your NRA mechanism based on

numbers of compliance or is it normalized?

A. The proposed violations performance measure is based on total occurrences with the company. It is -- it is not normalized by OHQ; however, based on our experience with this violation performance measure with other companies, particularly larger companies, in our recommendation in the Panel testimony we -- we recommended that any number of occurrences beyond 10 should not be counted towards the NRA. That takes into -- what's the word -- consideration for the larger number of non-compliances that could be found with large companies. That's not to say that with a company with 1 or 2 HQs you couldn't find 1000 non-compliances either. Even in those cases, it still would be capped at 10.

Q. So what -- you've testified on several of these panels. Are you saying that you have -- the 10% -- that 10 -- 10 occurrence threshold for National Fuel you say is different for other companies?

A. Other companies either had no cap or a 10 cap.

Q. Had -- I missed the last part.

A. It's either no cap or 10. There is no other variation.

Q. No cap or 10.

A. For a particular code requirement. Correct.

Q. Do you know which companies had no cap?

A. You have Niagara Nohawk, Con Edison, Grid New York, Central Hudson, and Corning's first variation -- version of the violations performance measure did not even have 100 basis point cap -- they had an unlimited exposure. I -- I think you're -- you're going along with lines of process. We have some experience now with National Fuel as to -- as to how this process will play out. The company received what we -- what we termed the NRA determination letter. I'll give you the date on it. It's August 4, 2016 and we can put this into the -- an exhibit. We haven't got this. In this letter you will see that Staff had sent NFG both a record audit letter and a field audit letter for the calendar year 2014 audit. The company responded to each audit letter.

Staff reviewed both the audit findings and the responses and in the NRA determination letter there were actually adjustments made based on that information collected and so it went into the final determination of the NRA and those -- that information is in -- it's in our testimony.

Q. Is that the letter from Mr. Wade?

A. Correct.

Q. To Mr. Ramsdell?

A. Correct.

Q. Did that letter identify 5 NRAs -- 5 violations?

A. Total of 6.

Q. 5 high-risk, 1 other?

A. Correct.

Q. Okay. Was that for 2015?

A. For calendar 2014. Calendar year 2014. I think reading the NRA determination letter you will see that just because there's a -- there's non-compliances identified by field staff that there is no consideration as to the company's position on these findings. I would like to note and this -- this goes back to the -- the damage prevention question. On page 2, there was a violation cited where the company did not accurately maintain a map to locate its inactive service line and it resulted in an excavation damage. That is in this report. That is an example where the company did not prevent an excavation damage related to a non-compliance required in 255. It's on page 2 of attachment 2.

Q. So you said that there were -- for

2014, there were 5 high-risk and 1 other risk violations?

A. Recommended to be counted towards the NRA for that calendar year.

Q. So can you explain why the 2015 Safety Report lists 25 high-risk violations for 2014?

A. Two reasons.

Q. Sorry?

A. Two reasons.

Q. Okay.

A. One, the gas safety performance measures report reports Staff findings and two, this determination was made after that report was issued.

Q. So you're saying that the 2015 Safety Report has the Staff findings before the company was -- gave its response and that --.

A. The report you're referring to was before the NRA determination letter, but what's in the violation performance measure report are Staff findings for all companies.

Q. Now the Appendix G doesn't say alleged violations. Does it?

A. This is not a legal document. It says identified.

Q. So these -- these are simply raw

numbers that are identified before the process works its way out?

A. Which process?

Q. The process that you just explained to me, Mr. Stolicky. The one where --

A. The NRA process is -- is a separate process from performance measures report.

Q. So the final number is 5 high-risk not 25. Correct?

A. In the NRA determination letter, it was determined that 5 high-risk in 2014 is what should be applied to the NRA.

Q. And it's also true, isn't it, that under the joint proposal that was approved, National Fuel has the appeal right up to the commission to make a further determination as to whether those are actual violations. Correct?

A. Correct.

A.L.J. LECAKES: Mr. Miller, it's just after 5:00. I'm trying to figure out if we should just retain the panel for tomorrow morning or how much time you have left?

MR. MILLER: What time is it now?

A.L.J. LECAKES: It's just after 5.

It's like 5:03.

MR. MILLER: I can probably can finish this up by -- by 5:30 at the latest.

A.L.J. LECAKES: Okay. And yeah, we'll keep going.

MR. MILLER: Okay.

A.L.J. LECAKES: Actually why don't we take a 5 minute break then.

(Off the record)

A.L.J. LECAKES: On the record. While we were off the record besides taking a break, there was a short discussion about some of the testimony that was submitted by Staff today including the corrected testimony of this Gas Safety Panel. Rather than redistributing a CD with testimony on it since there was one correction that seems to be omitted, the parties are stipulating to let NFG read in the testimony as they understood it to be corrected. Mr. Del Vecchio?

MR. DEL VECCHIO: Yes, Your Honor. The current testimony of the Gas Safety Panel states:

Question: What does the Panel recommend?

Answer: We encouraged the use of ILI within distribution's IM programs.

Question: Does this benefit the company's

customers?

Answer: The completed assessments of distribution's systems have identified several threats which if left unrepaired could directly impact public safety.

The last sentence I read was corrected by DPS Staff in Exhibit 191 which is also referred to as Exhibit KDH14 to the rebuttal testimony of Kevin House, NFG-DPS-127 revised, the last sentence should say the completed assessments of distribution's systems could identify several threats which if left unrepaired could directly impact public safety.

A.L.J. LECAKES: Thank you. I do understand what was read and I believe the record is clear on that point. Mr. Miller, when you're ready you can continue your cross examination of the panel.

MR. MILLER: I'm ready. I'll try to move it along Your Honor.

BY MR. MILLER: (Cont'g.)

Q. We're going to go now to Staff's answer to NFG-DPS-119. I'll give Your Honor and the panel a copy.

A.L.J. LECAKES: Thank you.

Q. Have you had a chance to look at the

-- your interrogatory response DPS119 -- NFG-DPS-119 that I handed you?

A. Yes.

Q. I'd like to refer you to the answer to Part I of that response and ask if it doesn't say in previous years, Staff has documented, recorded, and reported non-compliances as single violations with multiple occurrences. Do you see that?

A. Yes.

Q. And doesn't the response further state that the previous way Staff counted violations was consistent with that -- with the Pipeline and Hazardous Materials Safety Administration's required way of reporting statistics?

A. Yes.

Q. And that Federal Office of Pipeline Safety is also referred to as PHMSA, P-H-M-S-A. Correct?

A. Correct.

Q. And New York has a delegation from PHMSA to administer pipeline safety both on distribution systems and the interstate pipeline system in New York. Is that correct?

A. Not entirely. We have a delegated authority is how I understand it for distributions

systems. We are interstate agent for interstate pipeline customers.

Q. Okay. Fair enough. Does the response further state that this way of reporting does not reflect Staff's internal statistics of counting violations and occurrences as being synonymous?

A. That is what it says.

Q. When did Staff change its view of how it counted violations from the way that PHMSA counts them?

A. I don't -- I don't think your question is -- is correct as to what the response is saying. When it said this was consistent, it -- that means that when Staff reports its audit findings to PHMSA, their terminology was --it's violations and then pieces of evidence. We have -- and this is where I think the company and Staff Panel are sort of talking past each other. I think we should fill in the gap here.

As we moved from, I'm going to say, 5-6 years ago we started chipping away at developing the most consistent way to perform our audits possible across the state.

How we structure the formatting of the audit reports became more consistent and so where some -- some offices are operating almost like a silo in the sense

that they were calling violations and occurrences and then some were calling them violations with pieces of evidence. That terminology is -- is consistent with -- it's consistent in the sense that's how we report it to PHMSA, but when we move to be crossing I's and dotting T's consistent across the state, that's when you saw the language say violations with occurrences and it's why we say -- we say it's synonymous because every non-compliance with the regulation is an occurrence or violation.

We use the term violation because people outside of what we -- what we do in this world will understand occurrences so that's why you saw a change over that period is because we were making things consistent across the state and as these audit letters are being posted by the different rate cases -- you can look those up and see, but it's consistent.

Q. So you -- you would agree though that there was an inconsistency in the past that --

A. Terminology.

Q. -- in terminology?

A. But how we counted was -- was the same. The numbers are the same. The terminology was different and inconsistent.

Q. But is it your testimony that you --

you always counted occurrences and violations as being synonymous, interchangeable?

A. Yes.

Q. SO if there were 3 occurrences, would that be 3 violations?

A. Yes.

Q. Instead of 1 violation with 3 occurrences.

A. To us, it's the same.

Q. Would you agree that for some companies the number of occurrences were within a violation? In other words, 3 occurrences of one code section would be one violation?

A. That would have been reported to PHMSA as -- as one violation with 3 pages of evidence regardless of how it was written in the audit report.

Q. Let's talk about high-risk and other risk for a few minutes. You list 16NYCR255.625D related to the odorization of gas as an other risk violation. Correct? Those violations are -- I think it's in your testimony, but it's also in the Gas Safety Report at the end. You have the high-risk and other risk violations for every code section. So just to refresh, it's 6C -- 625 D, D as in David. It's in another risk section?

A. Do you recall if this was asked in IR? We think it was. We just can't remember which number. There were a lot of them.

Q. Yeah, it's in the 2015 report, Mr. Stolicky. Let me see. Let me try to short circuit this and then see if we don't have to come back around to something that is obviously taking a long time. So let -- let me just posit this to you. If there is a regulation section say for a period checking of some piece of equipment and my case was going to be odorization that comes in as other risk. One would expect that to be in the company's operating and maintenance plan as well too. Correct?

A. Correct.

Q. Okay. Is it the requirement of the operating and maintenance plan a high-risk section? 255603?

A. 603D is high-risk.

Q. It's high-risk. Correct?

A. Correct.

Q. So if the company, for example, were to put in something in its operating and maintenance plan that was more stringent than the regulations required -- you following me?

A. Yes.

Q. Okay. Isn't it possible that it incurs a high risk penalty simply for following its stricter O&M plan than the other risk penalty would have had if it had simply followed the regulations?

A. High risk has an associated -- higher associated NRA for high risk. 603D is in itself a requirement in the regs, odorization is a requirement in the regs. Following your procedure regardless of what the technical requirement is high-risk. The regulations require the company to file their -- well, first, draft operations and maintenance or O&M procedures outlining how the company will operate its system and then file those with Staff. That is the -- that is what the company follows.

The company makes determinations in its O&M plan similar to how as Witness House described along the lines of -- if there is a particular -- particular operational issue or relative threat in the company system and it has made a decision to go above and beyond the minimum pipeline safety regulations to do whatever that survey or inspection is at a higher frequency, there is a decision made for that up front somewhere along the lines.

The company recognized that it was the

better way to do business for whatever reason in its operating system and that is in the procedure that was filed regardless of what the minimum pipeline safety regulation is.

Q. Okay. So say the minimum pipeline safety regulation -- pipeline safety regulation says that the company will periodically test its odorization equipment and that would be a other risk violation under the safety code of Part 255. You follow?

A. Okay.

Q. If the company puts that into its O&M manual, right, and it violates that code section, isn't it true that not only does the company get an other risk violation, but by definition because it's in its O&M plan it gets a high-risk violation as well so it's getting two violations, one high risk one other risk, for the same infraction.

A. Both non-compliances would be in Staff's audit letters. The Staff audit letters that are sent to the company and the company responds to and as you've seen in the NRA determination letter, in those situation, the -- Staff did not recommend the company have an NRA applied for both instances.

A.L.J. LECAKES: I apologize for

interrupting. I don't like to do this, but I'm confused on the both in that statement. You said both twice and I thought in the hypothetical there was one instance of -- of non-gas odorization and the point being that there were 2 different types of violations under part 65 -- 655 that are being cited for, so when you use the word both, can you -- I mean I --

MR. STOLICKY: I -- I think there might be two different issues and I'm glad you caught onto this. If -- if let's say and this is going to be a hypothetical -- both are hypothetical. If the regulations say you shall inspect this device monthly, okay, if we perform a record audit. We pull it up and the company did it every two months. The technical requirement is they had to do it monthly, they did not do it. Now we look at their O&M plans that says how they're going to run their business. Okay? If they said that they were going to do it every month, then they did not follow their O&M plan which is a separate code requirement.

A.L.J. LECAKES: Right. I -- I think though that that changes the hypothetical a little bit. I think instead why don't we say so the company is supposed to do the inspection every month and they skipped January. They missed January. So you cite them for skipping

January and I think Mr. Miller's point is that so the code requirement is that they inspect it every month, they get hit for that whether it's -- you know -- other risk or -- or high risk, but at the same time it's also put that -- that they'll inspect this into its O&M plan so for the same miss in January that they had, they're getting hit for the fact under 655 that they -- they missed the inspection, but then they're getting hit for a violation of not following their O&M plan. Right?

MR. STOLICKY: That -- that is -- that is one of the -- one of the two situations that I think we were crossing paths here.

A.L.J. LECAKES: Okay.

MR. STOLICKY: The other one would be let's say the requirement is to inspect it every 2 months except that the company has determined that they should inspect it monthly. It's the higher risk for whatever reason. If they don't do it monthly, but they still did it every two months then that's a situation where they did not follow their O&M plan that was more stringent than the minimum requirements, but they still met the code requirement.

A.L.J. LECAKES: Right. I can appreciate that, but that -- it -- just so you're aware

that is a different hypothetical than the one --

MR. STOLICKY: It is. There's two separate conjectures here.

A.L.J. LECAKES: -- proposed by the company. Okay. I'm sorry to interrupt. Go ahead.

MR. MILLER: No, that's fine. Thank you, Your Honor. Thank you. We have nothing further.

A.L.J. LECAKES: Is there any other -- not Staff yet -- is there any other party that has any cross examination?

MS. WOEBBE: No, Your Honor.

A.L.J. LECAKES: Okay. I just have a couple of quick questions on a follow up to a couple of things that I asked Mr. House. You were here when I was speaking with Mr. House earlier. Is that correct?

MR. STOLICKY: Yes.

A.L.J. LECAKES: Okay. Do you recall I asked him about changes that he discussed on his testimony to reporting guidance on total damages and how they're measured. Before December 2015, they were measured without what he called hand digging or homeowner damages. After December 2015, they are now including that. You -- Gas Safety is now including that in its reporting. Is that correct?

MR. STOLICKY: I think we need to focus on the word reporting versus what is in the calculation. I think there's an assumption being made from the company that we need to clarify.

A.L.J. LECAKES: Actually I think --.

MR. STOLICKY: Are we reporting the data to us --,

A.L.J. LECAKES: I think it's pretty clear in the testimony that -- that the assumption being made here is that Staff was considering the new change to the -- the guidance as being included. Is that not what the Staff Panel intends?

MR. STOLICKY: As -- as we sit here today and we were in this room -- this same room back in May of last year 2015 to meet with all the companies including NFG to talk about our experience from 2003 and from all the companies and we -- we -- we took everyone's recommendations -- all the companies with Northeast Gas Association or NGA as to how to better modify the -- the reporting criteria and to collect data more accurate to what is going on out there and we -- we took basically every company's complaint and recommendation and then we -- we compiled it into the -- the new reporting forms that were sent out. I believe somewhere there was -- there was

talk of this being connected with the data audit, but it was actually a parallel audit because we've been doing this for over a decade and we wanted to improve the -- the actual measure themselves and so what we did and we're talking about the damage reporting form -- what we were not collecting in the past were hand damages. We were not collecting information on homeowner's -- the damage without the one call.

A.L.J. LECAKES: All right. So now you're collecting it.

MR. STOLICKY: So now we are collecting the data. It is on the reporting form, but that is not being plugged into the calculation that's in the report right now and so the assumption by the company is that just because they're reporting it, it's a -- because it's on the form that that's how the measure is going forward.

A.L.J. LECAKES: Okay. But I think it's a fair assumption. So what is the -- the Gas Safety Panel's actual proposal to include that in the future or not to include that in the future because it is being recorded now? It is a data point that the Gas Safety Panel will have.

MR. STOLICKY: The -- the -- the

reason we are collecting the data is -- well, one, we've never collected it so we don't know.

Two, we don't -- we don't have a plan to calculate the damage with all of that data, but as we discussed with all of the parties, coming down from PHMSA are new regulations in damage prevention and they want -- they want -- state law is if you have a damage prevention law to include all damages regardless of how they occur and we had a discussion with all the companies -- again, this is collaborative -- to collect that data so that we can make a case one way or another whether it's a big deal or whether it should be exempt.

A.L.J. LECAKES: Right. But still --

MR. STOLICKY: That's why we're collecting.

A.L.J. LECAKES: -- you're talking about reporting so what I'm -- what I'm asking is did Staff at least when it made its proposal about ramping these damage -- these total damage targets up, did Staff take into consideration the fact that new data is being reported in the future rate year that we're here about today that has never been collected before -- until 2016?

MR. STOLICKY: I just want to be clear in how we answer that.

A.L.J. LECAKES: Yeah.

MR. FAVREAU: Your Honor, I'm not really -- I'm not following I guess. What is the question?

A.L.J. LECAKES: Did the Staff Panel -- when you -- when you ramped up the target -- when you made your proposal to ramp up the targets from where they were in previous rate plans on total damages, did the panel take into consideration the fact that the reporting on the damages had changed such that it was clear that more damages -- more total damages were going to be reported because certain incidents that had not been required to be reported before were now going to be reported in the future?

MR. FAVREAU: I don't want to testify, but I think that's an unknown. Right?

A.L.J. LECAKES: What do you mean it's an unknown, Mr. Favreau?

MR. FAVREAU: Well, we will let the witnesses speak.

A.L.J. LECAKES: Okay.

MR. FAVREAU: Maybe I just didn't understand the question.

MR. STOLICKY: I can't predict what

will happen in the future. The only change with the targets is to make sure that all the companies in the state are reporting the ticket count properly and that's coming out of the data audit, but for the actual incremental damages the criteria hasn't changed from the past so again, homeowners that didn't call don't count.

A.L.J. LECAKES: Okay. I -- I think I got --.

MR. STOLICKY: There is no other way it's calculated.

A.L.J. LECAKES: I think I got what I -- I heard when I heard I can't predict what's in the future so --.

MR. STOLICKY: But that's not -- not with the recommended targets as we sit here today in this proceeding.

A.L.J. LECAKES: Right. The recommended targets are what they are in the testimony. The --.

MR. STOLICKY: Yes, but we're -- we're not adding damages to that calculation.

A.L.J. LECAKES: Well, that remains to be seen from what I understood from what you just answered.

MR. STOLICKY: What I -- what I meant by I can't predict the future is I don't know how we're going to break down that data and present it in the future Gas Safety Performance Measures Reports.

A.L.J. LECAKES: Okay.

MR. STOLICKY: We may look at hand damages and homeowner, but for the measures proposed here, those are not included. It's not -- this isn't new.

A.L.J. LECAKES: How would you propose when -- when you don't have a settlement and a joint proposal where a company has agreed with you, how do you propose that a company factors in that kind of unknown when -- when you're -- you're proposing a new -- a ramp up on a target like this? I mean. Let me -- strike my own question.

You understand the problem that that puts the company in when you testify to something and -- you know -- you -- you're telling them here you have a ramp up target based on past performance; however -- you know -- as -- as the -- the ads for -- for -- you know -- stocks and bonds sake past performance isn't necessarily indicative of future performance -- you know. How -- you know -- how can you assure me and the commission that that ramp up target is reasonable -- you know -- based on past

performance when past performance may not be the proper indicator of future performance because now there's new data?

MR. STOLICKY: There's a lot of parts to this question. I can say for sure that what is recommended by the panel, we can be clear on how that is calculated and what damages are included in that calculation. That's for the term of this rate plan. If a change happens in a future rate case filing and it would change how we did the calculation, then that's going to be a discussion in the future.

A.L.J. LECAKES: Right. But you understand that the company's point is that the changes already happened in December 15 -- December whatever it was 2015 by the reporting guidelines.

MR. STOLICKY: We changed what we're collecting -- what they were reporting to us.

A.L.J. LECAKES: All right. Okay.

MR. STOLICKY: That's the change.

A.L.J. LECAKES: All right. I have no further questions at this point. Do you want to approach for redirect?

MR. FAVREAU: Yeah, just very quickly.

A.L.J. LECAKES: Do you want to take

another room?

MR. FAVREAU: Let's step outside. It's easier.

A.L.J. LECAKES: Off the record.

[Off the Record]

A.L.J. LECAKES: All right. Let's go back on the record. Mr. Favreau?

MR. FAVREAU: We don't have any redirect, Your Honor.

A.L.J. LECAKES: Okay. Let's conclude today. Right now in our pre-hearing conference call we had talked about starting tomorrow at 9 a.m. Is that still good for people? Okay. We will start at 9 or as close to 9 as we can with people coming in, but Panel you are excused. I don't see anybody here. Mr. Stolicky, you're not on any other panels are you?

MR. FAVREAU: He's on the Policy Panel.

A.L.J. LECAKES: Okay. Mr. Stolicky, you are not excused in the sense that you are still -- are still sworn.

MR. PASINELLA: I'm also on --.

MR. FAVREAU: Yeah, you're also on the Policy Panel too.

A.L.J. LECAKES: Oh and Mr. Pasinella?

MR. FAVREAU: Yes.

A.L.J. LECAKES: All right. So Mr. Pasinella and Mr. Stolicky, you are still under oath. Actually I can swear you in again under the Policy Panel, but as far as your Gas Safety testimony is concerned, the Panel is excused. Thank you. We will resume tomorrow morning at 9 a.m. and we are off the record.

(The hearing concluded.)

STATE OF NEW YORK

I, HANNAH ALLEN, do hereby certify that the foregoing was reported by me, in the cause, at the time and place, as stated in the caption hereto, at Page 1 hereof; that the foregoing typewritten transcription consisting of pages 1 through 1402, is a true record of all proceedings had at the hearing.

IN WITNESS WHEREOF, I have hereunto subscribed my name, this the 12th day of October, 2016.