STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Docket DG 10-017

Direct Testimony
of
Frank Lombardo and Michael J. Adams

February 26, 2010

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I. INTRODUCTION AND BACKGROUND

Q. Please state your names and business addresses.

A. My name is Frank Lombardo. My business address is One MetroTech Center, Brooklyn, New York 11201.

My name is Michael J. Adams. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Mr. Lombardo, by whom are you employed and in what capacity?

A. Subsequent to the acquisition of KeySpan Corporation ("KeySpan") by National Grid plc in 2007, I was named the Director of US Planning for National Grid USA. In August 2009, my responsibilities shifted to a revenue requirement role. In this case, I am responsible for overseeing preparation of the Company's cost of service and revenue requirement filings and the associated exhibits.

Q. Please briefly describe your educational background and business experience.

A. I am a 1993 graduate of St. John's University with a B.S. degree in Accounting and also hold an M.B.A. degree in Finance from St. John's University. From July 1993 until September 1995, I was employed as an Associate Analyst in the Budgeting and Forecasting Department of The Brooklyn Union Gas Company. Since that time, I have served in a number of strategic positions and worked on a number of corporate initiatives within KeySpan Corporation, including serving as Assistant Supervisor of the Customer Accounting Area (1995 – 1997), Financial\Lead Analyst for Strategic Planning (1997 – 2000), Lead Analyst in Investor Relations (2000 – 2003), and Manager of Financial Planning for KeySpan Corporation (2003 – 2007), where I managed and coordinated the due diligence process for KeySpan Corporation during the period that it was considering its strategic business options. The process involved responding to numerous financial and strategic data requests from a variety of suitors. The process ultimately resulted in the acquisition of KeySpan Corporation by National Grid. Following the acquisition, I became the Manager\Director of Business Planning for National Grid (2007 – 2009), where I was responsible for preparing the National Grid U.S. long and short term financial plan by business segment, as well as integrating the U.S. planning process for all segments. The plans forecast the U.S. financial and operational position, supported corporate strategy, earnings guidance, credit rating agencies (S&P, Moody's and Fitch), and provided the basis for corporate merger and acquisition activity. In August 2009, I assumed my current responsibilities as a member of the National Grid rate case team.

Q. Have you previously testified before any regulatory agencies?

A. No.

Q. Mr. Adams, by whom are you employed and in what capacity?

A. I am a Vice President with Concentric Energy Advisors ("Concentric").

Q. Please describe Concentric Energy Advisors Inc.

A. Concentric provides financial and economic advisory services to a large number of 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, and energy contract negotiations. Our financial advisory activities include merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services, and transaction support services.

Q. Please briefly describe your educational background and business experience.

A. I have an MBA in Finance from the University of Illinois - Springfield and a BS in Accounting from Illinois College. I am a member of the American Institute of Certified Public Accountants and the Illinois Society of Certified Public Accountants. I have more than 25 years of direct experience in the public utility industry. I have worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the energy industry. I have managed and/or participated in a wide variety of consulting engagements and have testified in other regulatory proceedings and jurisdictions.

Q. Have you previously testified before any regulatory agencies?

A. Yes. My curriculum vitae, which is provided in Attachment FL/MJA-1, contains a list of jurisdictions in which I have testified.

Q. On whose behalf are you sponsoring this testimony?

A. We are sponsoring this testimony on behalf of EnergyNorth Natural Gas, Inc. d/b/a as National Grid NH ("National Grid NH" or the "Company").

Q. Are you sponsoring any exhibits as part of your filing?

A. Yes. We are sponsoring the following exhibits that have been included in this rate case filing pursuant to N.H. Code of Administrative Rules Puc 1604.07 and 1604.08, which were prepared under the supervision of Mr. Lombardo:

- Exhibit EN 2-1: Computation of Revenue Deficiency
- Exhibit EN 2-2: Schedule 1 – Operating Revenues
- Exhibit EN 2-2-1: Summary of Pro Forma Adjustments Income or Expense
- Exhibit EN 2-2-1A: Attachment - Summary of Pro Forma Adjustments
- Exhibit EN 2-2-2: Schedule 1A - O&M
- Exhibit EN 2-2-3: Schedule IB - Taxes Other Than Income Taxes
- Exhibit EN 2-2-4: Schedule 1C - Depreciation Expense
- Exhibit EN 2-2-5, p. 1: Schedule ID - Income Taxes - State Income Taxes
- Exhibit EN 2-2-5, p. 2: Schedule 1D- Income Taxes - Federal Income Taxes
- Exhibit EN 2-3, p. 1: Schedule 2A - Assets and Deferred Charges

- Exhibit EN 2-3, p. 2: Schedule 2B - Stockholders Equity and Liabilities
- Exhibit EN 2-3, p. 3: Schedule 2C - Materials and Supplies
- Exhibit EN 2-4: Schedule 3 - Rate Base
- Exhibit EN 2-4-1: Schedule 3A- Working Capital

We are also presenting the following schedules supporting the capital structure, cost of debt and the overall rate of return that were prepared by Company witness Robert B. Hevert:

- Exhibit EN 3-1: Overall Rate of Return
- Exhibit EN 3-2: Capital Structure
- Exhibit EN 3-2A: Capital Structure Excluding Goodwill
- Exhibit EN 3-3: Historical Capital Structure
- Exhibit EN 3-4: Capitalization Ratios
- Exhibit EN 3-5: Weighted Average Cost of Long Term Debt
- Exhibit EN 3-6: Cost of Short Term Debt
- Exhibit EN 3-7: Cost of Common Equity

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present the Company's overall revenue requirement in this proceeding, including: (i) the Company's proposal to calculate its required return on the capital invested in the Company's net rate base of used and useful assets based on an end-of-period balance as of June 30, 2009, as adjusted for non-growth capital expenditures and changes in deferred income taxes through September 2010; (ii) historic data for the test year pertaining to operations and maintenance ("O&M") expenses, general taxes, rate base and income taxes; (iii) an analysis of expense adjustments required to arrive at operating income for the year ended June 30, 2009; (iv) an explanation and analysis of certain pro forma adjustments to O&M, property taxes, rate base, and income taxes for the rate year (the adjusted test year is herein referred to as the "rate year"); and (v) National Grid NH's historic and pro forma cost of long term debt, capital structure, and overall rate of return for the test year, as determined in the testimony of Mr. Hevert.

Q. Please summarize the Company's request for rate relief in this case.

A. The Company is requesting an increase in base rates totaling $11,422,718, which is equal to the difference between the required income for National Grid NH based on the Company's proposed rate base and rate of return and the adjusted net operating income for the test year. The following table provides a high-level summary of the different components of National Grid NH's cost of service and revenue requirements:

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Attachment - Summary of Pro Forma Adjustment Income or Expense

	12 Months Ending June 30, 2009	Pro Forma Adjustments	Pro Forma Test Year	Proposed Rate Increase	Rate Year
Operating Revenues	175,770,354	(11,410,782)	164,359,572	11,422,718	175,782,290
Operation & Maintenance Expenses	155,706,773	(14,597,273)	141,109,499	-	141,109,499
Depreciation	9,693,262	(1,650,710)	8,042,552	-	8,042,552
Amortization	-	-	-	-	-
Loss from Disposition of Property	-	-	-	-	-
Taxes Other Than Income Taxes	4,191,305	598,613	4,789,918	-	4,789,918
Interest on Customer Deposits	19,557	-	19,557	-	19,557
			-		
Total Operating Revenue Deductions	169,610,896	(15,649,371)	153,961,526	-	153,961,526
Operating Income Before Federal Income Taxes	6,159,458	4,238,589	10,398,046	11,422,718	21,820,764
State Income Taxes	7,892	374,165	382,057	970,931	1,352,988
Federal Income Taxes	430,570	1,008,887	1,439,457	3,658,125	5,097,583
Total Income Taxes	438,462	1,383,053	1,821,515	4,629,056	6,450,571
Operating Income After Federal & State Income Taxes	5,720,996	2,855,536	8,576,532	6,793,661	15,370,193
Rate Base	170,722,365		169,006,099		169,006,099
Rate of Return	3.35%		5.07%		9.09%

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Computation of Revenue Deficiency

	Updated Pro Forma
Rate Base Proposed	169,006,099
Rate of Return	9.09%
Income Required	15,370,193
Adjusted Net Operating Income	8,576,531
Deficiency	6,793,661
Tax Effect	1.6814
Revenue Deficiency	**11,422,718**
Revenue Increase	11,422,718
Income Tax Rate	41%
Income Tax	4,629,056

Q. Please provide details on the Company's earned rate of return for the test year ended June 30, 2009 as compared to its allowed rate of return.

A. The table above, as well as Exhibit EN 2-2-1A, *Attachment - Summary of Pro Forma Adjustments*, which is submitted as part of the Company's filing, shows that the Company earned an overall rate of return of 3.35% for the test year ended June 30, 2009, which is substantially less than the authorized overall rate of return of 8.28% and is also below the proposed overall rate of return of 9.09% that the

Company is seeking in this case. For purposes of the comparison, the test year return is calculated on a 13 month average historic rate base, adjusted to reflect an out-of-period increase to the level of deferred income taxes.

Q. What factors led to the Company's decision to seek rate relief in this case?

A. The Company is seeking an increase in rates because it is earning significantly less than its allowed rate of return. As shown above, the Company's overall rate of return is approximately 500 basis points below its current authorized rate of return. This under-earning results primarily from a material increase in rate base (a majority of which was non-revenue producing in nature) since the test year used in the Company's last rate proceeding (Docket No. DG 08-009), brought about by the Company's continued commitment to maintaining the integrity of the gas distribution system in New Hampshire. The effect of the increase in rate base on the Company's return is compounded by the inherent regulatory lag that exists in the ratemaking methodology that has traditionally been applied by the Commission to determine the Company's rates. Regulatory lag, which is discussed in the pre-filed testimony of Dr. Susan Tierney, has been created, in particular, by the use of a 13-month average historical test year rate base. In addition to the capital investment that the Company has made since the test year in its last rate case, the Company's operating expenses have increased significantly across numerous expense categories such as the cost of labor, benefits, uncollectible accounts and most other operating expenses. These increases in invested capital and operating expenses coupled with the flat trend in average use per customer that the Company has experienced as a result of customer conservation and energy efficiency improvements to homes and natural gas heating equipment have created an environment that makes it effectively impossible for the Company to achieve the return on equity authorized by the Commission at current rates.

Q. You indicated that the Company's operating expenses have increased significantly. Please describe National Grid NH's efforts to mitigate this increase.

A. National Grid has undertaken cost control efforts throughout its organization, including:

- A corporate-wide requirement to absorb inflation in annual budgets;
- Travel restrictions;
- No merit-based wage increases in 2009 for management employees;
- Consolidation by National Grid USA of its operating facilities for its New England utilities;
- Consolidation of National Grid USA's medical plans and implementation of a self-insured plan; and
- Re-negotiation of the Company's office supply vendor contract.

Mr. Stavropoulos and Ms. Fleck also discuss steps the Company has taken to operate more efficiently and contain costs.

III. OVERVIEW OF DEVELOPMENT OF OPERATING EXPENSES INCLUDED IN REVENUE REQUIREMENT

Q. Please summarize the basis for the operating expenses included in National Grid NH's revenue requirement in this proceeding.

A. The operating expenses reflected in the proposed revenue requirement are based on an historical test year, which is the twelve months ended June 30, 2009, with pro forma adjustments for known and measurable changes relating to the twelve months thereafter.

Q. Does the proposed revenue requirement also include costs that are assigned or allocated to National Grid NH by its parent and/or affiliate companies?

A. Yes, National Grid NH is part of a holding company structure, and, as is typical of such company structures, receives services from its parent and affiliate companies for which it is charged. Thus, expenses that are included for purposes of determining the Company's revenue requirement can either be costs incurred directly by the Company or allocated costs incurred by its service company affiliates, which we will describe below.

Q. What affiliates provide services and allocate costs to National Grid NH?

A. Three former KeySpan companies provide services to National Grid NH – National Grid Corporate Services LLC (formerly known as KeySpan Corporate Services LLC), National Grid Utility Services LLC (formerly known as KeySpan Utility Services LLC), and National Grid Engineering & Survey Inc. (formerly known as KeySpan Engineering & Survey Inc.). National Grid USA Service Company, Inc. also provides services to National Grid NH.

Q. What types of costs are allocated rather than incurred directly?

A. Costs that are allocated, as opposed to being incurred directly at the Company, include those costs that are utilized across National Grid USA, such as those services provided by National Grid's Human Resources, Accounting, Treasury and Facilities Management departments.

Q. What services do the various affiliates provide to National Grid NH?

A. In accordance with the regulations of Public Utilities Holding Company Act of 1935 (the "PUHCA") and New York State Public Service Commission requirements, KeySpan created three distinct service companies: (i) KeySpan Corporate Services LLC, providing traditional corporate and administrative services; (ii) KeySpan Utility Services LLC, providing gas and electric transmission and distribution systems planning, marketing, and gas supply planning and procurement; and (iii) KeySpan Engineering Services & Survey

Inc., providing engineering and surveying services to affiliates. All three companies are collectively referred to in this testimony as the KeySpan Service Companies. Allocation methodologies, approved by the SEC, have been in use since 2001 to allocate certain service company costs to affiliates. National Grid USA Service Company Inc. is the legacy National Grid USA Service Company. It provides services related to the implementation of common corporate policies, streamlined business processes and integrated information services. As with the KeySpan affiliates, reliance on a common service company for these services enhances the cost effectiveness of the services provided.

IV. DETAILED REVIEW OF OPERATING EXPENSE EXHIBITS

Q. Please provide an overview of the schedules and exhibits you have prepared in support of your testimony.

A. Exhibit 2-1 provides the computation of National Grid NH's revenue deficiency. The revenue deficiency is calculated as the difference between the required income for the Company based on its rate base and weighted average cost of capital, and the adjusted net operating income for the test year, as calculated in subsequent schedules. Exhibits 2-2 through 2-4 provide details of the components of the Company's revenue requirement. Exhibits 3-1 through 3-7 provide details on National Grid NH's capital structure and weighted average cost of capital.

Q. Please describe the data presented in Exhibit EN 2-1: Computation of Revenue Deficiency.

A. This exhibit presents the computation of the revenue deficiency and resultant increase in the base revenue requirement of $11,422,718, based on a proposed overall allowed rate of return of 9.09% on a rate base of $169,006,099.

Q. What is provided in Exhibit 2-2?

A. Exhibit 2-2 contains a schedule of the different components of National Grid NH's operating revenues and cost of gas.

Q. Please describe the data presented in Exhibit EN 2-2-1: Summary of Pro Forma Adjustments Income or Expense.

A. This schedule presents a summary of the pro forma adjustments to both revenues and expenses aggregated by cost of service category (*i.e.*, revenues, O&M expenses, depreciation, amortization, taxes other than income taxes, interest on customer deposits, and income taxes). The individual cost of service components, along with the pro forma adjustments, are provided in more detail in the exhibits discussed below.

Q. Please explain Exhibit EN 2-2-2.

A. Exhibit EN 2-2-2 includes a summary schedule and 17 supporting schedules. It shows the test year O&M expenses as well as adjustments, where appropriate, for known and measurable changes during the twelve months following the test year and the comparable amounts as recorded in each of the two preceding fiscal years. The amounts presented on each of the schedules are compiled in two forms of presentation. The first form of presentation provides the expense amounts aggregated by provider company (*i.e.*, the KeySpan Service Companies and National Grid USA Service Company, Inc.). This allows the amounts allocated from each of the KeySpan Service Companies and National Grid USA Service Company, Inc. to be distinguished from the amounts generated directly within the utility. The second form of presentation aggregates the expense amounts in accordance with the specific O&M account classifications, as prescribed in the FERC Chart of Accounts.

Q. Please explain the specific schedules in Exhibit EN 2-2-2.

A. The Summary Schedule shows total O&M expenses - including cost of gas - for the historical test year ended June 30, 2009 of $155,706,773, and an adjusted expense level of $141,109,499 after known and measurable changes. The reduction is primarily due to the cost of gas adjustments identified in schedule Exhibit EN 2-2. The detailed schedules behind the summary are as follows:

Schedule 1, consisting of two pages, presents the cost of gas purchased and produced for the historical test year and the pro forma test year. The gas cost expense for the historical test year is $130,797,571. The second page summarizes the gas cost adjustments made to the per-books historical test year gas costs. The first column indicates the test year costs recorded on the Company's books. The second column, "Pro Forma Adjustments," includes a detailed list of all the adjustments made to the historical test year gas costs. These adjustments include a weather normalization adjustment, removal of certain gas costs including interruptible sales, off-system sales, broker balancing charges, and various accounting adjustments (which include occupant account gas costs and the reallocation to gas costs of the portion of uncollectible accounts expense—also called bad debt—that is attributable to the gas supply function as well as production and storage credits from the O&M expense accounts). These adjustments result in a reduction of $18,640,961, resulting in total adjusted gas costs for the rate year of $112,156,610. Additional details on the weather normalization and other adjustments contained in this schedule are discussed and sponsored by Company witness Ms. Ann Leary in her pre-filed testimony.

Q. Please provide an overview of Schedule 2 of Exhibit EN 2-2-2.

A. Schedule 2, consisting of nine pages, shows operating labor expense for the historical test year and the pro forma test year. The details of the calculation of the pro forma labor increase are shown on pages 2 through 9.

Q. Has labor expense increased since the Company's test year in its last rate proceeding?

A. Yes. Total labor expense has increased 4% since the year ended June 30, 2007 (*i.e.*, the date of National Grid NH's test year end in its last rate proceeding) to the test year in this rate case ended June 30, 2009.

Q. What were the main drivers of the increased labor expense?

A. The primary driver for the increase in labor costs is the additional field collectors that the Company brought on in an effort to increase its account collection efforts. In addition, normal wage increases as prescribed by our negotiated labor contracts have resulted in an increase in labor expense.

Q. What do the detailed calculations (*i.e.*, pages 2 through 9) regarding labor expense show?

A. Page 2 of Schedule 2 details the labor adjustments, which are broken down between union and management employees and by base pay increases versus performance-based pay (referred to as variable compensation for management and gainsharing for unions). All employees except those who are members of local 1049/1381 participate in an annual performance program that provides for incentive compensation in addition to base pay. These two components comprise the total compensation package. The program is designed to ensure that the total compensation package offered by the Company is competitive, after taking both components into account. The plan in which management employees participate is called Performance for Growth. Eligible union employees participate in an Annual Union Goals Program. Each plan is designed to ensure that employees are incentivized to contribute in a positive manner to areas that are within their scope of responsibility.

Page 3 of Schedule 2 details the union wage adjustment. Because the utility and the service companies have different unions, and the fact that there are multiple unions within the individual companies, we used the average union wage increase of 1.98% for National Grid NH, 4.87% for National Grid Corporate Services, 4.82% for National Grid Utility Services, and 5.65% for the National Grid USA Service Company. Page 4 of Schedule 2 shows the adjustment to management wages of 4.55%. Pages 5 through 8 detail the number of employees in each company (broken down between union and management), the average salary, the overall increase for management and union, and the composite increase used on pages 3 and 4. Page 9 provides details on the pro forma adjustments made to the incentive compensation component.

Q. Please explain how the overall increase for each union and for management was developed.

A. The Company's total compensation package includes a base salary component and a variable pay component. The total package including the base and variable component is competitive with the market. Pay for individuals may vary, but the total for all employees is known and measurable. The overall union increase was based on the actual contracted increase for each union. Each union has a different contract year and a different contractual increase. Management's overall composite increase of 4.55% is made up of two components: (1) a 1.50% payroll increase for promotion and inequity adjustments for all management employees effective as of July 1, 2009, compounded by (2) a 3% salary increase that will take effect as of June 27, 2010. There were no merit increases to management pay in 2009 due to the economic climate, and therefore the 1.5% adjustment is lower than the increase that will occur in 2010. The adjustment that will occur in 2010 is more in line with historical levels, as shown in the table below.

National Grid (former KeySpan Corporation)
Management Employee Increases
New York and New England

	Merit Increase Percentage	Promotion/Equity Percentage (1)	Total
September 26, 2004	3.5%	0.75%	4.25%
March 27, 2005	2.0%	0.75%	2.75%
March 26, 2006	3.5%	0.75%	4.25%
April, 2007	3.8%	0.75%	4.55%
July, 2008	4.75%	0.00%	4.75%
July, 2009	0.00%	1.50%	1.50%
July, 2010	3.00%	1.50%	4.50%

(1) Promotions, market adjustments, responsibility increases

Q. Please return to page 1 of Schedule 2 of Exhibit EN 2-2-2 and summarize the labor adjustment.

A. Page 1 shows the total labor adjustment, which is an increase of $33,873. Page 2 shows (i) the wage increase of $344,027, broken down by union (a $148,979 increase) and management (a $195,048 increase) (ii) the adjustment for variable compensation (a $299,840 reduction), and (iii) the adjustment for gainsharing (a $10,315 reduction). The bottom of the page shows the total adjustment.

Q. Please continue with your explanation of the schedules in Exhibit EN 2-2-2.

A. Schedule 3 of Exhibit EN 2-2-2 shows the adjustments to contract labor expense. The pro forma increase shown on Schedule 3-1 relates to paving expenses. The Company utilizes two outside firms — Brenton Contracting and R.H. White — to perform paving. Contract rate escalations with these firms, which were effective May 1, 2009, provided for a 3% and 3.5% increase, respectively. R.H White performs 96% of the paving work, with Benton Contracting providing the balance. The weighted average contractual increase in paving costs is 3.48%. However, since two months of the escalation is reflected in contract labor expense through the test year ended June 30, 2009, the Company adjusted the increase to result in a weighted average increase of 2.68% through May 1, 2010 of the rate year – assuming no further known and measurable increase following the expiration of the contract term. This percentage was applied to the test year paving costs, resulting in a pro forma adjustment of $17,243. In addition, recent changes to municipal bylaws in Manchester and Concord expand roadway restoration requirements that increase restoration cut back requirements following excavation in public roadways. These changes result in incremental costs of $212,411. The increased costs are assessed to the Company in the form of increased permit fees. The incremental costs from the paving contracts and the restoration cut back requirements, when added to the total test year contract labor of $1,090,079, yield the pro forma test year amount of $1,319,732.

Q. What does Schedule 4 of Exhibit EN 2-2-2 show?

A. Schedule 4, consisting of two pages, shows the health and hospitalization expense in the test year of $1,554,788, and pro forma adjustments totaling $169,844, resulting in a rate year expense of $1,724,632. The health care percentage increases are shown on page 2. The percentage increases represent the overall composite rate increases for all medical and dental plans based on current premiums. The percentage increase in premiums experienced by each company was applied to the historical test year expenses to yield the adjustment of $169,844 to the test year amount.

Q. How has health and hospitalization expense changed since the filing of National Grid NH's rate case in DG 08-009, and what are the drivers of that change?

A. Health and hospitalization expense has increased by $264,479, or approximately 18%, since the Company's last rate filing. Health care costs have increased consistently above the general rate of inflation for many years – at times at a rate of three to four times the rate of general inflation. This increase is consistent with National Grid's actual utilization and is also consistent with national projections for health care trends and the projections gathered by the Company's own health care consultant.

Q. Please explain Schedule 5 of Exhibit EN 2-2-2.

A. Schedule 5 presents the historical test year balance of other employee related expenses and benefits of $450,459. These costs consist primarily of employee expense reimbursements for business related expenses. There are no adjustments to the test year amount.

Q. How have other employee related expenses changed since the filing of National Grid NH's rate case in DG 08-009, and what are the drivers of that change?

A. The account known as other employee expenses has increased by $98,605, or 28%, since the Company's last rate filing. The increase is driven by an increase in the Company 401K match, as well as an increase in other employee related expenses such as meals, lodging, reimbursement for use of personal car, training, safety clothing and equipment, reimbursement of airfare, rail and cab fare utilized in Company travel and operational performance.

Q. Please explain Schedules 6 and 7 of Exhibit EN 2-2-2.

A. Schedule 6 and Schedule 7 present the National Grid NH pension and post retirement benefits other than pensions ("OPEB") expenses of $1,995,447 and $1,019,805, respectively, for the twelve month historical test year period ended June 30, 2009. The Company is requesting that the Commission authorize specific deferral accounting treatment, a reconciling mechanism, and the collection of deferred pension and OPEB's through the Company's local distribution adjustment charge ("LDAC"). Under the Company's proposal, the test year amount would be included in base rates, subject to a reconciling mechanism included in the LDAC.

Q. Before describing the deferral accounting, reconciling mechanism and collection process, please explain why the Company is seeking this treatment for pension and OPEB expenses.

A. Pension and OPEB expenses are a significant expense for the Company. The actual test year expense was $1,995,447 for pensions and $1,019,805 for OPEB's, which combined represent approximately 12% of total non-commodity O&M

expense. Due to many factors beyond management's discretion, it is likely that during the period in which rates are in effect that pension and OPEB expenses will be either significantly greater or less than the test year amounts. Set forth below are the Company's actual pension and OPEB expense for the last five fiscal years and the projected expense for the current fiscal year and the next five fiscal years. As you can see, there is a significant variation in these expenses over time. What is particularly notable is that, while total pension and OPEB expense is relatively flat over the long term, from year to year it can move up or down by relatively large amounts.

						Long Term Plan - US GAAP					
	Actual FY 2005	Actual FY 2006	Actual FY 2007	Actual FY 2008	Actual FY 2009	Estimated FY 2010 4/09-3/10	Estimated FY 2011 4/10-3/11	Estimated FY 2012 4/11-3/12	Estimated FY 2013 4/12-3/13	Estimated FY 2014 4/13-3/14	Estimated FY 2015 4/14-3/15
ENH Total Pension \ OPEB	$3,342,970	$3,217,638	$3,276,174	$2,371,402	$2,457,129	$3,967,882	$4,098,983	$3,930,797	$3,952,804	$3,850,988	$3,747,524
$ Change		($125,332)	$58,536	($904,772)	$85,727	$1,510,752	$131,101	($168,186)	$22,007	($101,816)	($103,464)
Percent Change		-4%	2%	-28%	4%	61%	3%	-4%	1%	-3%	-3%

Specifically, pension and OPEB expense calculations rely heavily on actuarial assumptions, and other factors to calculate the estimated cost of these benefits. Employee turnover, retirement age, life expectancies, administrative expenses of the pension plan, assumed earnings on plan assets, and the date on which a benefit becomes fully vested are some of the more important actuarial assumptions. Other factors such as the discount rate employed and fluctuations in the stock market together create many uncertainties in estimating pension and OPEB expenses. Because of these circumstances, the Company is requesting the

Commission to authorize an alternative to the ratemaking approach for pension and OPEB expenses that has been employed in the past.

Q. What causes the volatility of this expense?

A. The volatility results directly from the manner in which the Company is required to determine and account for this expense. Unlike most other expenses, where the Company books an actual cost that it incurs, with regard to pension and OPEB's, the Company is required by financial accounting standards to book an accrual that is based on numerous actuarial and other assumptions. To determine this amount, the Company engages an actuarial firm that in turn utilizes various assumptions relating to employee turnover, retirement age, life expectancy, administrative expenses of the pension plan, assumed earnings on plan assets, and the date on which plan participants benefits become fully vested. Other factors such as the discount rate employed and fluctuations in the stock market combine to create many uncertainties in estimating pension and OPEB expenses. In addition to market volatility, the funding obligation is affected by frequent changes in the law, changes in the applicable discount rate and changes in actuarial assumptions. As a result, amounts recorded on a company's books for pension and OPEB's vary significantly from year to year. Depending on the uncertainty related to the timing of rate cases, rates can grossly over or under collect funds related to pension and OPEB expense. This is unfair to both customers and the Company.

Q. How would the proposed reconciling mechanism work?

A. The Company has included the historical test year pension expense of $1,995,447 and OPEB expense of $1,019,805 in the rate year revenue requirement. Under the proposed reconciling mechanism, any difference between the actual amount of expense that must be recorded in accordance with financial accounting standards and the amount of expense allowed to be recovered in this proceeding would be deferred for later recovery from or credit to customers.

Q. How do you propose the deferred amount be collected from or returned to customers?

A. The December 31 balance, positive or negative, would be collected or refunded through the local distribution adjustment charge ("LDAC") during the subsequent year beginning with the next Peak Period, when the LDAC is normally adjusted.

Q. Please explain why a pension/OPEB mechanism like the one the Company is proposing is beneficial to customers.

A. As stated previously, pension and OPEB expense is large and has significant volatility. Any amount included in the cost of service is just as likely to be overstated as understated in any given year. The Company's proposed reconciliation mechanism (1) would allow the Company to recover pension and OPEB costs incurred in providing service to customers and (2) would ensure that customers pay no more and no less than the amounts needed to meet the

Company's obligation to employees. A reconciling mechanism would safeguard customers from inaccurate actuarial and health care cost assumptions and mitigate the volatility in rate and expense differences. Because of the fact that the pension and OPEB expense booked in any given year is based on estimates and various actuarial assumptions, a major factor affecting the amount the Company accrues in any given year is an adjustment to correct for variations between the prior years' assumptions and actual data. Over the long run, a reconciling mechanism that is based on the Company's actual expense rather than a test year assumption will provide better matching between revenues and prudently incurred costs. In other words, the Company would recover no more than the expense it actually incurs, keeping the customer whole through carrying charges.

Q. What is your response to concerns raised by Staff in past cases regarding a reconciling mechanism?

A. The Staff has indicated in past proceedings that it opposes a pension and OPEB reconciling mechanism. The basis for that opposition appears to be that the Company has the ability to determine the level of pension and other post-retirement benefits to offer its employees. Of course, on the margin the Company does have some limited ability to determine the amount of these benefits that it offers to its current employees, but the reality is that (1) in this day and age an employer like National Grid NH and its affiliates must offer some form of pension and related employee benefits in order to remain competitive and attract the skilled work force it requires to serve its customers and operate its system safely, (2) the Company goes to significant lengths to ensure that its benefits are competitive and not excessive, and (3) the vast majority of the expense reflected on the Company's books relates to benefits to which current and former employees are already entitled and therefore there is absolutely nothing the Company can do today to change the cost it incurs.

We would respectfully suggest that Staff's concern regarding the Company's ability to affect the level of benefit costs on the margin should be weighed against the considerable evidence that the Company has in fact managed this cost prudently as well as the complete lack of control that the Company has with regard to the manner in which the amount of the expense is determined, the significant size and volatility of the expense, and the impact that the expense can have (up or down) on the Company's earnings. The Company is not in the business of earning a profit or taking a loss on its pension and OPEB benefit plans, nor should it be.

The problem has become more serious since the Staff first began considering the issue, and it bears reconsideration. This expense is not like any other O&M item in terms of volatility and magnitude. As we discussed above, in a single year this item can swing by many hundreds of thousands of dollars and have a major impact on the Company's overall earnings. It is highly unpredictable. The returns on equity that the Commission has been granting and can be expected to grant in the future simply are not likely to adequately compensate investors for the huge risk associated with the major swings in this expense and its impact on earned rates of return. The ability of a utility to apply for a general rate increase is not an effective or efficient means to address this concern, and it would not serve the Commission, customers or the Company well to rely on it as a means to address this serious problem.

Q. You indicated that pension and OPEB expense has the potential to significantly affect the Company's earnings. Can you give the Commission some sense of the magnitude of that impact?

A. As mentioned above, pension and OPEB expense on a combined basis represent approximately 12% of total non-commodity O&M expense and greater than 50% of test year operating income after federal and state income taxes.

Q. Please return to your explanation of the schedules in Exhibit EN 2-2-2, beginning with Schedule 8.

A. Schedule 8 adjusts the historical test year payroll taxes included in O&M expense of $520,455 by the composite wage increases in each company (discussed above as part of the description of Schedule 2). This calculation yields an adjustment to payroll taxes of $14,607, resulting in a pro forma test year expense of $535,061. Payroll taxes are included in O&M expenses, rather than taxes other than income taxes, because when labor expenses are allocated from the KeySpan Service Companies and the National Grid USA Service Company to National Grid NH all benefits, including payroll taxes, follow the labor.

Q. Please summarize Schedule 9 of Exhibit EN 2-2-2.

A. In Schedule 9, test year expenses for outside services of $3,917,223 were adjusted by $598,334 to $3,318,889 primarily to remove rate case expenses associated with Docket No. DG 08-009. Recovery of these expenses is addressed separately in accordance with Commission practice.

Q. How have outside services expenses changed since the filing of National Grid NH's rate case in DG 08-009, and what are the drivers of that change?

A. Outside services have increased by approximately $650,855, or 24% since the Company's last rate filing. Approximately $500,000 of this increase is related to additional allocations from the National Grid USA Service Company for outside consultants utilized in informational and instructional advertising and other non-contractor charges.

Q. Please explain Schedule 10 of Exhibit EN 2-2-2.

A. Schedule 10 adjusts test year postage expense by $13,130, from $358,386 to $371,515, to reflect the increase in domestic postal rates put into effect on May

12, 2009 by the U.S. Postal Service. The weighted average increase of 3.29% is based on applying the postal rates to the Company's mail mix.

Q. Please explain Schedule 11 of Exhibit EN 2-2-2.

A. Schedule 11 provides the level of contributions, tickets and sponsorships expenses of $31,578, all of which have been eliminated from the O&M expenses, and therefore are not included in the Company's cost of service.

Q. Why did the Company eliminate the entire amount of contributions, tickets and sponsorships expenses?

A. The following items are included in this category – Contributions to Salvation Army, Boys and Girls Club, CEO budget, Community Affairs, economic development, corporate diversity. Although a significant portion of these expenses are partially or entirely promotional in nature and therefore a benefit to customers, they were removed consistent with Commission precedent and applicable regulations.

Q. Please explain Schedule 12 of Exhibit EN 2-2-2.

A. Schedule 12 presents the Company's dues and memberships expenses. The test year amount is $53,649, and there is no pro forma adjustment to this figure. Expenses in this category include items such as American Gas Association membership dues and corporate diversity\equal employment opportunity initiatives.

Q. What does Schedule 13 of Exhibit EN 2-2-2 show?

A. Schedule 13 shows "other expenses," which are comprised of numerous expenses that are aggregated and presented at their historical test year balances. Examples of the types of items included in this schedule include, among others, costs associated with building services, fleet, sales programs, and materials and supplies.

Q. How has the category of expenses labeled "other expenses" changed since the filing of National Grid NH's rate case in DG 08-009, and what are the drivers of that change?

A. Other expenses have decreased by $1,590,550, or 45.7%, since the filing of the last rate case. The drivers of this decrease were: (1) a decrease in advertising expense – all advertising has been eliminated in our pro-forma adjustments; (2) a decrease in incentive programs (which include our free boiler program) – of which 50% of the total incentive program has been eliminated in our pro-forma adjustments, and (3) reduction in miscellaneous other costs including building services, printing \ mailing, and permits.

Q. What is shown on Schedule 14 of Exhibit EN 2-2-2?

A. Schedule 14 shows uncollectible expense of $3,759,035 for the test year, which is increased by $1,759,442 to $5,518,477. The increase results from applying the proposed uncollectible percentage of 3.36% (based on six month lagged – 12-month revolving revenue of $171,642,530 and a December 2009 12-month revolving year end write-off of $5,763,008) to adjusted test year revenues of $164,359,572. The Company proposal includes a recovery of uncollectible expense at our most recent experience of write-off to revenue percentage. As is discussed by Mr. Stavropoulos and Ms. McCarthy, recovery of this expense in full is critical to the Company's ability to earn its allowed return. By way of example, a 1% gap between the Company's allowed bad debt rate and the level actually incurred by the Company (e.g., if the Company's actual level of recovery is 3.36% of gross revenues, but the Company's rates provide for recovery of only 2.36%) equates to a reduction of approximately 100 basis points in its ROE.

Q. What is shown on Schedule 15 of Exhibit EN 2-2-2?

A. Schedule 15 presents an adjustment of $2,240,786 to reclassify to gas costs the gas cost portion of bad debt credits and production and storage credits that were recorded in the test year O&M accounts, as presented in Schedule 1. This adjustment is discussed in more detail in Ms. Leary's testimony.

Q. Please explain Schedule 16 of Exhibit EN 2-2-2.

A. Schedule 16 shows the incremental expense of $776,886 associated with the increased level of collection activities undertaken or proposed to be undertaken by the Company.

Q. Please describe the proposed program changes associated with collection cost activities for the Company.

A. The Company has continued to take steps to enhance its collections efforts since the end of the test year. The nature of these changes and the reasons for them are addressed in the testimonies of Company witnesses Ms. Tracey McCarthy and Mr. Mark Hirschey. The changes being implemented by the Company will result in additional expenses of $776,886 as shown on Schedule 16. These costs include (i) an additional $211,468 for two new hires tied to the collection efforts and (ii) $565,419 for the changes that are discussed in Ms. McCarthy's and Mr. Hirschey's testimonies.

Q. Do the O&M expenses included in the Company's revenue requirement reflect synergies from the 2007 merger between National Grid and KeySpan, as required by the Merger Rate Agreement?

A. Yes, but as contemplated by the EnergyNorth Merger Rate Agreement, approved in Order No. 24,777 dated July 12, 2007, the calculated savings have been offset by the costs incurred to achieve the savings. The merger savings provision of the

Merger Rate Agreement was intended to share between customers and shareholders any net savings achieved as a result of the merger. Because of the difficulty of demonstrating the existence of savings generated by the merger (*i.e.*, that costs that otherwise would have existed are not present in the Company's revenue requirement), the agreement included a specific methodology for calculating the savings. The methodology provided for in Docket DG 06-107 stated that if the Company files a second rate case within five years (the "Rate Agreement Period") of the closing of the merger (as it is in the instant case), the Company will be allowed the opportunity to prove the net synergy savings (*i.e.*, after subtracting the costs to achieve) deemed to have resulted from the merger ("Actual Synergy Savings") and add back fifty percent of those savings to the cost of service in the second rate case ("Savings Allowance"). In reviewing the methodology set forth in the Merger Rate Agreement, it became clear that Account 1806 – Joint Expenses – Credit was inadvertently included in the original calculation. This credit is actually a production and storage credit that was included as O&M expense, and therefore should not have been among the accounts used to demonstrate merger savings. Therefore, I removed this item when performing the calculation of savings. The treatment of the production and storage credit is discussed in more detail in Ms. Leary's testimony. When utilizing the synergy savings proof methodology, net of account 8492K – Joint Expenses – production and storage credit, Actual Synergy Savings have been calculated to be $181,327. Recognizing the methodology provided the opportunity to prove net synergy savings (*i.e.*, after subtracting the costs to achieve) and that annual costs to achieve when amortized over 10 years equate to approximately $409,000, the Company has offset the savings by a similar amount of costs to achieve up to, but not beyond, the level of synergy savings calculated. In other words, the Company did not include in its revenue requirement any costs to achieve in excess of the merger savings demonstrated by the agreed-upon formula, but did include costs to achieve up to the savings that could be shown to exist.

Q. Please explain Exhibit EN 2-2-3, Taxes Other Than Income Taxes.

A. Below we have summarized the methods used to pro form the rate year tax expenses shown on Exhibit EN 2-2-3.

Real Estate Taxes – Real estate taxes through the end of the test year (*i.e.*, June 30, 2009), were adjusted for known and measurable changes that have occurred in the period between the end of the test year and the filing of this rate case. The historical amount presented for real estate taxes, $3,855,759, was based on the actual taxes paid using the actual bills received through December 31, 2009. National Grid NH is billed semi-annually for property taxes, with invoices received in June and December in all towns other than Concord, which is billed quarterly. In addition, the Company is billed quarterly for the State of New Hampshire Utility Tax, with the most recent invoice received in December 2009. Thus, we were able to adjust the test year property tax expense for amounts actually billed through December 2009, on an annualized basis. The total adjustment was $601,410, resulting in a pro forma test year expense of $4,457,169. This amount will need to be further adjusted when the December 2010 tax bills are received because those bills relate back to the tax year beginning April 1, 2010 and will reflect the actual tax assessments for the current tax year. (In June 2010, the Company will receive its first tax bills for the twelve months beginning April 1, 2010, but those bills will simply show the tax rate in effect in the prior year.) It is critical to the Company that the property taxes reflected in its revenue requirement be updated to be as current as possible because the Company has been experiencing substantial property tax increases and anticipates that that trend will continue for the foreseeable future. The update is consistent with the Commission's practice of making pro forma expense adjustments because the change will be effective as of April 2010, which is within twelve months after the end of the test year. The same type of adjustment is being proposed for both municipal and state property taxes.

<u>Federal FICA Taxes and Federal and State Unemployment Taxes</u> – Historical test year payroll-based taxes of $520,437 ($979 for unemployment insurance, $514,269 for FICA taxes, and $5,189 for unemployment tax) have been adjusted based on the overall change in payroll for the Company (*i.e.*, -1.88%, as shown in Exhibit 2-2-2, Schedule 8, page 2. The overall change in payroll is discussed above as part of the description of Schedule 2). State unemployment taxes

expense also includes an adjustment of $3,500 to reflect the mandated increase in unemployment insurance in New Hampshire for National Grid NH's entire employee population. The resulting adjustment totals $(6,267) ($3,482 for unemployment insurance, $(9,652) for FICA taxes, and $(97) for unemployment tax), resulting in a pro forma test year expense of $514,170 ($4,461 for unemployment insurance, $504,617 for FICA taxes, and $5,092 for unemployment tax).

Other State Taxes and Capitalized Payroll Taxes – Other state taxes and capitalized payroll taxes (($184,891) in the historical test year) have also been adjusted by $3,470 based on the overall payroll increase for the Company, resulting in a pro forma test year expense of ($181,421).

Q. Please explain Exhibit EN 2-2-4.

A. This schedule shows the total booked depreciation expense of $9,693,262 for the test year, which was reduced by $1,650,710 to $8,042,552 for the pro forma rate year. This $1,650,710 adjustment reflects the adoption of the recommendations presented in the depreciation study that was conducted on behalf of the Company in 2007 (the "2007 Depreciation Study") based on December 31, 2006 plant balances. In addition, the adjustment includes $181,327 of amortized costs to achieve – reflecting the level of synergy savings achieved, as discussed above. The pro forma rate year also includes an adjustment to the additional pro-rated amount of depreciation expense associated with the September 2010 adjustment for non-growth capital that the Company is proposing, which we describe later in our testimony.

Q. Does the depreciation adjustment include the amortization of National Grid NH's depreciation reserve surplus that was calculated as part of the 2007 Depreciation Study?

A. Yes. As discussed in the Commission's Order Granting Delivery Rate Increase in Docket No. DG 08-009, the parties in that docket agreed that National Grid NH would amortize the Company's depreciation reserve surplus, as calculated in the 2007 Depreciation Study, at a rate of $933,588 per year. Consistent with the Commission's order, the Company has recognized a decrease to its overall depreciation expense in this proceeding of $933,588. This amount is included in the $1,650,710 total depreciation adjustment.

Q. Please explain the data and calculations shown in Exhibit EN 2-2-5, page 1 (State Income Taxes), Exhibit EN 2-2-5, page 2 (Federal Income Taxes), and page 3 of EN 2-2-5 (Computation of Utility Interest Deduction).

A. Exhibit EN 2-2-5, page 1, presents the pro forma state income tax expense. The expense is calculated by applying the statutory rate of 8.50% to the Operating Income before Income Taxes and Interest Charges, as shown on Exhibit EN 2-2-

1, less the interest deduction shown on page 3 and net flow-through additions and deductions.

Exhibit EN 2-2-5, page 2, presents the pro forma federal income tax expense and is calculated by applying the statutory rate of 35% to the Operating Income before Income Taxes and Interest Charges, as shown on Exhibit EN 2-2-1, less the interest deductions, the net flow-through additions and deductions and the state income tax expense shown on Exhibit EN 2-2-5, page 1. Exhibit EN 2-2-5, pages 1 and 2, also detail the current and deferred income tax expense. The current income tax expense is computed by applying the statutory rates to the current taxable income. The deferred income tax expense is computed by applying the statutory rates to the amounts in the section labeled "Timing Differences."

Page 3 of Exhibit EN 2-2-5 computes the pro forma test year interest expense that is used in the income tax calculations. The interest expense is derived by multiplying the rate base as shown on Exhibit EN 2-4 times the weighted interest component of the rate of return shown on Exhibit EN 3-1.

V. <u>DEVELOPMENT OF RATE BASE</u>

Q. Please discuss the Company's approach to determining rate base in this case.

A. For purposes of determining its revenue requirement, the Company has utilized a test year-end rate base, updated to reflect non-growth capital additions through

September 30, 2010. The Company is seeking to update its rate base from the traditional test year average approach because it has made substantial non-revenue producing investments since the end of the test year. As discussed by Ms. Fleck and Dr. Tierney, the Company expects this trend to continue, and therefore it is also seeking an annual rate adjustment mechanism to reflect certain non-revenue producing capital additions on an ongoing basis. As I will explain in more detail below, as it happens, there is an a one time reduction in rate base that the Company booked after the close of the test year that has the effect of offsetting the increase resulting from non-revenue producing investments through the end of September, but the Company believes it is still appropriate and will be consistent with making annual adjustments on a going-forward basis to use a September 30, 2010 rate base figure for non-revenue producing capital investment in this case. The Company has used a September 2010 non-growth capital adjustment date as compared to a December 2010 cutoff date to give the Commission adequate time to review the impact of the step adjustment before rendering a decision.

Q. The Commission has traditionally used a 13-month average rate base for purposes of determining rates on the grounds that this approach provides for the most accurate matching of revenues to test year expenses. Does National Grid NH's proposed use of a period-end rate base violate the principle of matching revenues with expenses?

A. No. The concept of adjusting and updating the revenues and expenses that make up the revenue deficiency calculation to account for known and measurable changes to test year items, on the one hand, while, on the other hand, eliminating certain non-recurring or non-recoverable items, already looks beyond a strict year-end definition to provide for a reasonable basis upon which to charge customers for future service. The process of adjusting O&M items essentially "normalizes" the foundation upon which rates will be determined while taking into account as much current information as is possible. By using a period-end rate base, we are establishing a basis for determining rates that is most representative of the utility's current financial status and investment, in much the same vein as pro forma adjustments to O&M expenses are made. In addition, given the flat or declining consumption pattern that the Company has been experiencing and can be expected to continue to experience, we believe the more important regulatory policy issue in this proceeding is the fact that the historical ratemaking process does not provide the Company with a meaningful opportunity to earn its allowed return under the conditions that exist today.

Q. Is there any regulatory precedent in New Hampshire for using a period-end rate base and for updating rate base for post test period rate base additions?

A. Yes, there is. Our understanding is that there are a number of cases where the Commission has updated a utility's rate base for ratemaking purposes in order to provide a reasonable opportunity to earn the authorized rate of return and reduce the need for frequent rate cases. Forest Edge Water Company was ordered in its

2009 rate case to retain a consultant to perform a study of needed cost improvements to its system. In that case, the Commission said "if the Company undertakes and completes any capital improvement(s) called for in the study by the end of 2011, it may request an additional step adjustment to its rates to reflect the cost of the capital improvements completed."[1] In Fryeburg Water's 2009 rate case, the Commission noted in its order in regards to post test-period capital additions that, "[c]consistent with [its] policy of allowing recovery of expenditures for large capital projects which, if not recoverable, would have a detrimental impact on a utility's rate of return, we find that these capital improvements ought to be recovered through a step adjustment to rates."[2] Also, in DE 06-028: Public Service Company of New Hampshire's Petition for Approval of Delivery Service Rates Order No. 24,750, dated May 25, 2007, the Commission noted "[f]urther, the step adjustments proposed in the settlement are consistent with what we have approved in the past. See *Unitil Energy Systems, Inc.* Order No. 24,677 (October 6, 2006) slip op. at 20 and cases therein cited. The step adjustments will allow PSNH to include in distribution rates base non-revenue producing plant that is used and useful, consistent with RSA 378:28." We have not done an exhaustive review of Commission orders on this issue, but it is our understanding that there are numerous occasions when the Commission has

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1 DW 08-160; Order No. 25017, September 23, 2009.

2 DW 07-115; Order No. 24,950, March 20, 2009.

determined that updating rate base beyond the mere use of a test year average was appropriate.

Q. Returning to the schedules, please describe Exhibit EN 2-3.

A. Page 1 of this exhibit presents the balance sheet for assets and deferred charges for the historical test year and the two preceding fiscal years. Page 2 presents the same information for stockholders equity and liabilities. Page 3 presents the same information for materials and supplies.

Q. Please describe Exhibit EN 2-4: Schedule 3 and how the Company arrived at its test year rate base figure.

A. The Company arrived at its test year rate base by calculating the end-of-period balances in its rate base accounts. These rate base accounts include total gas plant (plant in service and completed construction not classified) of $308,862,633, non-interest bearing Construction Work in Progress ("CWIP") of $0, and the accumulated reserve for depreciation of ($106,480,932). National Grid NH has also adjusted rate base for non-growth capital additions of $9,575,890 and the accumulated reserve for depreciation of ($6,466,136). The Company will update rate base for any variances between the budgeted and actual amounts of capital additions through September 30, 2010.

Q. What does "non-interest bearing CWIP" represent, and how does the Company calculate it?

A. Non-interest bearing CWIP is an account used by the Company to record construction projects that are of short duration and that do not accrue AFUDC. Due to the nature of these projects (*i.e.*, small, repetitive type mains and services projects), the Company records them under blanket project numbers that remain perpetually "open" from an accounting perspective. Thus, while these projects may go into service from an operations perspective, they remain recorded as CWIP from an accounting perspective until the Company makes manual adjustments to re-classify them to plant in service. Because of the small size of these projects, the manual adjustments are made on an approximately quarterly basis for purposes of efficiency, as opposed to making an accounting adjustment as each individual project goes into service.

Q. Has the Company included non-interest bearing CWIP in rate base in this proceeding?

A. No. As discussed above, the Company has historically reclassified non-interest bearing CWIP to plant in service on a periodic basis. However, to avoid confusion as to what the amounts in non-interest bearing CWIP represent (*i.e.*, plant in service that is awaiting accounting reclassification), National Grid NH's accounting group thoroughly reviewed the projects in the non-interest bearing CWIP account and made the necessary manual adjustments to reclassify projects that had gone into service in preparation for this rate filing. This process resulted in a $0 balance in non-interest bearing CWIP as of June 30, 2009.

Q. What adjustments has the Company made to rate base?

A. Page 2 of Exhibit EN 2-4 summarizes the adjustments to the rate base. The first adjustment to rate base is an addition of $2,757,128, representing deferred regulatory costs, comprised almost entirely of FAS 109 deferrals.[3] The second adjustment is a reduction of $39,867,830, relating to deferred federal and state income taxes that are related to delivery rate base. These deferred taxes primarily reflect the effects of the timing differences related to the use of accelerated depreciation for tax purposes but straight-line depreciation for financial accounting purposes, cost of removal, unamortized investment tax credits and the timing differences of other net costs of the Company.

Schedule 3A, "Working Capital," shows the derivation of the total working capital allowance of $1,059,948, which has been included as an addition to the average test year rate base. Cash working capital is made up of two components, prepayments and a cash working capital allowance, as shown in the schedule. For

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[3] Note, the $2.7 million balance related to FAS 109 deferrals is completely offset by a *negative* FAS 109 asset (*i.e.*, an asset with a credit balance). National Grid NH had a regulatory asset of $2,789,398 on its books at the time of the KeySpan merger due to a deficiency in New Hampshire state income taxes recorded at the time of the merger due to an increase in New Hampshire state income taxes that the Company believed it would recover in a future rate proceeding. At the time of the merger, there was no plan to file a rate case, so an adjustment was made to increase goodwill with a credit to deferred taxes.

purposes of determining the non-gas related cash working capital allowance, we applied the position settled upon in Docket DG 08-009 and applied the net lag factor of 18.24 days to net O&M expense. For gas-related cash working capital, a 18.24 day net lag was used. The source of the 18.24 day lag was the lead/lag study prepared and filed in DG 08-009. The Company is in the process of updating the lead/lag study under the direction of Mr. Mike Morganti of Management Application Consultants and will update the factor, including its impact to rate base, following the filing of this case. The net effect of all of these adjustments to rate base results in an adjusted rate base for the test year of $169,006,099.

Q. What major items are included in the accumulated deferred income tax ("ADIT") balances for the updated rate base for the update being proposed as of September 30, 2010?

A. As we discussed above, ADIT reflects the difference between normal (straight line) book depreciation and tax (accelerated) depreciation. In this case, the Company has booked a substantial increase in its ADIT to reflect a change in position that it has taken on its federal tax return as it relates to the classification of certain expenditures as being capital rather than operating in nature.

Q. Please explain the income tax credit associated with the Company's position regarding capital expenditures.

A. In its fiscal year 2009 federal income tax return filed December 11, 2009, National Grid Holdings, Inc. changed its method of accounting for routine repair maintenance costs deductible under Internal Revenue Code Section 162. Previously, for tax purposes certain main replacements had been treated as capital expenses, consistent with their ratemaking treatment. Specifically, the Company makes certain main and service replacements that are properly capitalized from a ratemaking standpoint, but that, because they do not extend the life of the gas network, can be expensed for tax purposes. In connection with this change, National Grid Holdings, Inc. recorded a one-time tax expense, for these tax repair costs, equal to the un-depreciated amount of prior costs of this nature on its books at the time of the change. This change resulted in a $2.3 billion reduction in National Grid Holdings, Inc.'s taxable income for Fiscal Year 2009. The resulting tax benefit for National Grid NH was approximately $9 million.

Q. How is the Company accounting for this tax credit?

A. The Company is crediting accumulated deferred taxes by approximately $9 million, representing its portion of the tax benefit. The Company recognizes that the Company's tax position is subject to audit and adjustment by the Internal Revenue Service ("IRS"). The Company is providing the full benefit of the tax credit (*i.e.*, reduction in rate base) to customers as part of the process of updating the test year rate base, but requests authorization to defer for future recovery the amount of any future adjustments or disallowance by the IRS for the Company's treatment of this item on its tax return, along with carrying charges at the weighted average cost of capital approved in this proceeding.

Q. Given that the Company's tax position is subject to audit and adjustment by the IRS – how would any adjustment to the current tax treatment be addressed?

A. If the Company were required by the IRS to adjust its new tax treatment associated with repair costs, the Company would petition the Commission for an adjustment to rates for the rate base impact of the IRS position. Any adjustment approved by the Commission could flow through the Company's LDAC.

VI. RATE OF RETURN

Q. What is the overall rate of return that the Company is proposing?

A. The Company is proposing an overall rate of return of 9.09%, as shown on Exhibit EN 3-1. This is based on a capitalization ratio of 50% long-term debt and 50% equity, a long-term debt cost rate of 6.99% (yielding a weighted average cost for long-term debt of 3.49%), and a common equity cost rate of 11.2% (yielding a weighted average cost for common equity of 5.6%). The sum of the weighted average costs of equity and long-term debt equals the overall rate of return of 9.09%.

Q. How did you determine the capitalization ratios that you used?

A. The capital structure used by the Company was dictated by the EnergyNorth Merger Rate Agreement approved in Docket No. DG 06-107, which stipulated that in any rate case filed in the ten years following the agreement, the Company would be required to use a debt to equity ratio of 50/50 for determining its overall rate of return. In addition, as a result of a settlement reached in Docket DG 06-122, all of the short-term debt that was outstanding as of June 30, 2007 was refinanced with long-term debt, and therefore the cost rate of the debt portion of the Company's capital structure for this case is equal to the cost of its outstanding long-term debt.

Schedule EN 3-2A shows the Company's capital structure at June 30, 2009, excluding the goodwill recorded on the Company's books at that time. As the schedule shows, after removing the goodwill from the Company's equity, the common equity ratio at the end of the test year was 47.81%, approximately equal to the 50% equity ratio dictated by the Merger Rate Agreement.

Q. How was the weighted average cost of long-term debt shown on Exhibit EN3-5 calculated?

A. The settlement in DG 06-122 provided that the cost of the long term debt being put in place to replace the Company's short term debt was 7.02%. Since that time there has been a slight change in the composition of the Company's long term debt to reflect the current level of unamortized call premiums following the passage of time since our previous filing, and therefore the Company has reduced the cost of long term debt to 6.99% from 7.02% as was calculated and approved in DG 06-122. Schedule EN 3-5 shows the calculation of the weighted average cost of long-term debt.

Q. What cost rate did the Company use for the common equity component of its capital structure?

A. The Company is using a return on equity of 11.2%, as discussed in the testimony of witness Mr. Robert Hevert.

Q. Does this conclude your direct testimony?

A. Yes.

Michael J. Adams
Vice President

Michael J. Adams has over twenty-five years of direct experience in the public utility industry. He has worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the utility industry. As a consultant, Mr. Adams has provided expert testimony or reports before the Arkansas Public Service Commission, the City of El Paso, Texas, the Hawaii Public Utility Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Missouri Public Service Commission, the Oklahoma Corporation Commission, the Ontario Energy Board, the Pennsylvania Public Utility Commission, and the Public Utilities Commission of Texas.

REPRESENTATIVE PROJECT EXPERIENCE

Rates/Regulatory/Strategy Projects

- Provided regulatory strategy support to a Midwestern electric utility regarding potential strategies for an upcoming rate proceeding. The Company had not filed a rate case in over 20 years. NCI was retained to provide insights, research and expert advise as to potential issues to pursue in the upcoming rate proceeding.
- Performed a review of shared service costs for a large Midwestern combination utility. Evaluated the reasonableness of allocated costs to those of other utilities and outsource providers. Provided expert testimony before the regulator regarding the appropriateness of the costs.
- Retained by Hawaii Electric Light Company to provide an assessment of the reasonableness of AFUDC charges accrued associated with the installation of two combustion turbines.
- Provided strategic and business planning services to a public traded company which is attempting to enter the utility financing business. Continue to work with the company to refine the service offerings within a regulated utility environment and to identify new business opportunities.
- Provided rate case support for two combination utilities. The primary objective of the filings was to unbundle the costs of the electric business to establish delivery service rates. During the engagement, assisted the Companies with the functionalization of plant and common costs; preparation of minimum filing requirements; preparation of direct testimony; and response to data requests.
- Assisted with the preparation of a gas rate case filing for a Midwestern gas utility. The project included the determination of the revenue requirement including an assessment of the proper level of cash working capital. Prepared the filing requirements associated with the rate case.
- Provided assistance to a large Midwestern combination utility in developing a response to a regulator-initiated complaint case pertaining to the Company's existing rates and alternative regulation mechanism. Provided testimony on issues related to cash working capital.
- Reviewed the credit and collection practices of a large Midwestern gas company. Advised client as to regulatory environment and potential changes that could be made to existing regulations.
- Provided assistance to an investor-owned combination utility on a number of occasions. He has performed the following tasks:
    - Examined the rate base and operating statements of the Company to determine the costs associated with the distribution business. This unbundling effort examined the method by which administrative and general expenses were allocated as well as the assignment of

general and intangible plant. Provided support responding to staff and intervenor inquiries related to the cost unbundling process.
    - Submitted testimony on behalf of the Company related to an A&G study introduced in conjunction with the delivery services cost unbundling proceeding.
    - Provided regulatory support for the preparation of a filing to create a fossil-generation subsidiary.
    - Consulted with the Company regarding a pending Commission-mandated management audit. Developed strategies for improving the likelihood of obtaining beneficial results for both parties.
- Provided assistance to a large northwest combination utility in preparation for a rate filing. Provided an independent assessment of the Company's requested revenue requirement.
- Assisted a Midwestern gas company with the preparation of a rate filing. The filing introduced new concepts pertaining to alternative regulatory mechanisms, lost and unaccounted for gas, and weather normalization.
- Prepared a cost of service model for a medium-sized municipally owned electric utility. The project included recommendations related to rate design and alternative cost recovery mechanisms.
- Provided regulatory assistance to a large Midwestern electric company on issues related to the level of capital and operations and maintenance expenses to be included in an unbundled distribution rate.
- Assisted a large east coast combination utility with an analysis of various utility services. Examined the Company's internal costs of providing the services versus those of external providers. Developed strategies to expand, divest, or make more competitive the Company's services.
- Consultant for business and cost separations study performed for a Canadian gas utility which will culminate in evidentiary hearings and evidence associated with the creation of a non-regulated subsidiary.

Cash Working Capital

Have performed and supported cash working capital requirements of regulated utilities on behalf of:

- AmerenUE – Missouri
    - Electric
    - Gas
- Ameren Illinois Companies (AmerenCILCO, AmerenCIPS, AmerenIP)
    - Electric
    - Gas
- Arkansas Oklahoma Gas Corporation
- Centerpoint Energy
- Hydro One
    - Distribution Business
    - Transmission Business
- Illinois Power Company
    - Electric
    - Gas
- Integrys Energy
    - Peoples Gas
    - North Shore Gas
- Missouri Gas Energy
- Toronto Hydro
- T.W. Phillips Gas and Oil Company

Accounting/Budgeting Assignments

- Reviewed the time and materials charging practices of a large east coast utility. The review led to the revision of charging practices.
- Reviewed the indirect charges practices of a large east coast utility. Provided recommendations modifying the charging practices between capital and expense.
- Reviewed the charging practices of a large electric power authority related to the charging of storm restoration expenses. Identified expensed activities which could be capitalized.
- Evaluated a large eastern combination utility's efforts to implement activity-based management principles.

Reliability-Related Projects

- Provided expert testimony on behalf of Allegheny Power regarding the appropriateness of reliability standards which had been recently established by the Pennsylvania Public Utilities Commission.
- Researched and summarized all regulatory initiatives related to service quality measures across the country on behalf of the Massachusetts distribution companies. Developed a report, which was presented to the Massachusetts Department of Telephone and Energy, outlining existing standards and the applicability of such standards for benchmarking the performance of the distribution companies against available information pertaining to such standards.
- Assisted with the review of historical reliability performance for two Midwestern combination utilities. Analysis required identification and mitigation of drivers of interruptions, both in terms of frequency and duration. Employed structured analytical approach to estimate costs of complying with Commission-established reliability "sets".
- Provided regulatory support for a Midwestern combination utility on issues related to electric distribution system reliability. Assisted with development and presentation of responses to regulatory requests.
- Prepared alternative mechanisms for a Midwestern utility's consideration pertaining to alternative forms of regulation on issues related to electric distribution reliability.
- Assisted with the preparation of a Midwestern utility's annual report to the regulator on issues related to electric distribution reliability.
- Assisted a Midwestern combination utility prepare for and respond to a management review of the Company's transmission and distribution system reliability. Prepared a synopsis of the Company's historical performance and key initiatives designed to maintain or improve reliability performance.
- Advised senior management on regulatory strategies for responding to numerous inquiries by/presentations to state regulators on issues related to supply-side and delivery service reliability.
- Assisted a Midwestern combination utility develop an Operations Compliance program for its electric distribution business.
- Assisted an investor-owned combination utility with evaluation and response to Commission rulemaking proceedings related to state-wide reliability rules.
- Prepared a status report for a municipality pertaining to the progress of reliability-related initiatives on behalf of a large Midwestern utility.

Litigation/Audit Support Projects

- Performed a review of the customer service functions of a medium sized natural gas company in the eastern United States. The review included an assessment of the company's compliance with existing PSC rules and regulations.
- Developed a methodology to assess the level of potential damages related to the delayed start-up of a landfill gas-to-energy facility.

- Performed an assessment of a large gas company's PBR mechanism. Regulators alleged that the mechanism had been manipulated to benefit the Company. Reviewed and analyzed documents and assisted with the legal defense on behalf of the Company.
- Project Manager for an effort to assist regulated telephone company during a PSC-ordered management audit. Prepared and debriefed witnesses to be interviewed by PSC auditors. Prepared responses to document requests. Analyzed company data to identify trends and areas of concern that could be identified during PSC audit. Briefed company senior management as to status of audit and potential findings and recommendations. Reviewed and commented on factual accuracy and reasonableness of draft management audit report.
- Assisted a sewer district prepare for a management audit initiated by the governing board of the district. Providing audit training as well as pre-audit assistance.
- Managed and served as lead consultant during a diagnostic and focused review of a mid-sized electric and gas company on the east coast. Served as lead consultant on areas related to Finance and Accounting.
- Served as lead and engagement director during a focused management audit of a mid-sized gas company on the east coast. Served as lead consultant on issues related to capital budgeting.
- Served as lead consultant during a litigation effort to evaluate the prudence and reasonableness of efforts related to the construction of a multi-state pipeline.
- Support consultant in the areas of Plant Management and Operations for a southwestern electric company.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2007 – Present)
Vice President

Navigant Consulting, Inc. (1995 – 2007)
Managing Director

Illinois Commerce Commission (1983 – 1995)
Deputy Executive Director

Illinois Power Company (1981 – 1983)

EDUCATION

M.B.A., Finance, University of Illinois, Springfield
B.S., Accounting, Illinois College

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant
American Institute of Public Accountants
Illinois Society of Certified Public Accountants
