STATE OF NEW HAMPSHIRE

Before the

PUBLIC UTILITIES COMMISSION

DOCKET DG 08-009

ENERGYNORTH NATURAL GAS, INC.
d/b/a
NATIONAL GRID NH

Rebuttal Testimony of Gary L. Goble

December 15, 2008

Prepared by:

Management Applications Consulting, Inc.
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Reading, PA 19609
Phone: (610) 670-9199 / Fax: (610) 670-9190

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REBUTTAL TESTIMONY OF GARY L. GOBLE
ON BEHALF OF
NATIONAL GRID NH

TABLE OF CONTENTS

LIST OF ATTACHMENTS

Attachment Number	Description
GLG-LL-4	Hypothetical Lead-Lag Base Case
GLG-LL-5	Revenue Lag Added to Base Case
GLG-LL-6	Simple CWC Addition to Rate Base
GLG-LL-7	Improved CWC Calculation
GLG-LL-8	CWC Reduced to Exclude Return
GLG-RD-6	Unitil Compliance Filing, Table 7 (Uncollectible Accounts Expense)
GLG-RD-7	Uniform System of Accounts - 874 Mans and Services

INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Gary L. Goble. I am a managing consultant with the firm of Management Applications Consulting, Inc. ("MAC"). MAC's headquarters is 1103 Rocky Drive, Suite 201, Reading, Pennsylvania 19609. My business office is 11405 Cezanne Court, Austin, Texas 78726.

Q. Are you the same Gary L. Goble who presented direct testimony on behalf of National Grid NH ("Company") concerning cash working capital, lead-lag studies, class marginal costs to serve and rate design?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony addresses issues concerning:

1. The cash working capital ("CWC") and lead-lag studies, raised by George McCluskey on behalf of the NHPUC staff ("Staff"),
2. The natural gas delivery service marginal cost study ("MCS"), raised by Lee Smith and Arthur Freitas on behalf of the NH Office of Consumer Advocate ("OCA"), and
3. The Company's proposed rate design, raised by both Staff and OCA.

Q. Please summarize your rebuttal testimony concerning the computation of cash working capital.

A. Mr. McCluskey has proposed adjustments to the lead-lag study I presented in my direct testimony. Those adjustments would dramatically decrease the level of CWC included in rate base. While the lead-lag study I submitted systematically addressed all of the timing differences between the revenues recorded by the Company and the expenses comprising its revenue requirement, Mr. McCluskey instead proposed to selectively pick and choose items to be included in the cash working capital allowance. If adopted, his adjustments would undermine the Company's ability to earn a reasonable return on its investment because his adjustments fail to recognize the full amount of the capital invested by the Company in conducting its business.

Q. Please summarize your rebuttal testimony concerning the marginal cost study.

A. Staff generally concurred with the results of the marginal cost study ("MCS"), but proposed four minor adjustments. These adjustments are in error for the reasons explained below. In addition, the OCA's consultants criticize some of the general assumptions incorporated into the MCS, using arguments more commonly applied to accounting or embedded cost of service studies. They go on to identify four alleged flaws. I will address these issues as well and explain why these criticisms are incorrect.

Q. Please summarize your rebuttal testimony concerning rate design.

A. The OCA witnesses attempt to raise issues concerning the role of marginal costs in the design of rates that have been addressed many times in the past by the NH PUC. The OCA witnesses argue that an MCS should not be used in the design of rates and that in this docket a simple "across-the-board", or equi-proportional, adjustment should be made to all existing rates. In addition, both the OCA and Staff argue that the Company's proposed customer charge increases should be reduced. Furthermore, Staff proposes the implementation of flat rates as a replacement for the existing declining block rates. I will demonstrate that the Company's customer costs are actually far greater than the customer charges proposed in the Company's rate design proposal and that the imposition of smaller increases in the customer charge along with flat rates will continue economically inefficient intra-class subsidization far into the future.

LEAD-LAG STUDY

Summary of Staff Adjustments

Q. Please summarize the changes and associated dollar amounts proposed by Staff associated with the Company's Lead Lag Study.

A. Staff has advocated four adjustments to the lead-lag study, all of which I believe should be rejected by the Commission. These adjustments include:

1. Removing non-cash expenses (uncollectible accounts expense and depreciation);
2. Removing Return;
3. Establishing 45 day lag on short term debt; and
4. Reducing collection lag by two days.

Assuming these adjustments are made sequentially, the CWC and the reduction to the requested CWC resulting from these changes is:

No.	Description	CWC	Reduction	Cumulative Reduction
	As Filed	4,127,997	0	0
1	Remove Depreciation & Uncollectibles	2,396,286	1,731,711	1,731,711
2	Remove Return	1,778,169	618,117	2,349,828
3	Add lag to Short Term Debt	1,715,433	62,736	2,412,564
4	Reduce Collection Lag	1,545,750[1]	169,683	2,582,247

Q. You indicated that Mr. McCluskey selectively included revenues and costs in the computation of CWC. How did he justify this?

[1] The figures here vary slightly from those provided by Mr. McCluskey due to rounding. For example, Exhibit GRM-9 shows CWC to be $1,547,211, a variance of less than 1/10 of a percent.

A. Mr. McClusky proposes a very narrow definition of cash working capital that has the effect of selectively excluding portions of the Company's revenue requirement. Interestingly, when asked in discovery for the source of his definition of "Delivery-related Cash Working Capital", he was only able to cite to testimony filed on behalf of consumer advocates in the states of New Jersey, California and Utah. He did not provide a single Public Utility Commission order or other authoritative source to support his position.

Mr. McCluskey computes CWC as the timing differences between the cash expenses paid by the utility and the collection of revenue associated with those expenses. Instead of employing arbitrary exclusions, I utilize a more general definition so that my lead-lag study includes all revenues and all expenses that comprise the Company's revenue requirement. The Company's receipt of all cash from customers is delayed, so it is logical that a cash working capital adjustment should net the impact of delayed cash receipt from the cash that can be generated from delayed payment of expenses. Using the definition I recommend, the CWC adjustment to rate base will allow the utility's stockholders a reasonable opportunity to earn the rate of return allowed by the PUC on both a cash basis and on an accrual basis. Using Mr. McClusky's definition, stockholders are denied this opportunity.

Q. Can you provide a simple example of the effect of limiting CWC to the Staff's narrow definition?

A. Yes, the Company books revenue when a sale is made (i.e., upon delivery of gas). The collection of those revenues will typically lag the sale by a month or two. The stockholders must wait until the revenue is collected to have use of the funds. The revenues to be collected represent the reimbursement for cash expenses <u>as well as</u> non-cash expenses (such as depreciation) and return on investment. The limited definition used by Mr. McCluskey provides customers all of the benefits from their delayed payments, but only compensates stockholders for a portion of the delayed receipt of revenues.

Q. Why is it inappropriate to exclude non-cash expenses and their associated revenue requirements from the lead-lag study?

A. The concept of accrual accounting, used by virtually all public utilities, is to record revenues and expenses as they are incurred, not as the cash flows. Accrual accounting records revenues when services are delivered - that is, when they are earned and when an obligation for payment or right to receipt of payment is recognized. Similarly, the expenses incurred to provide services to utility customers are booked when their benefit is received, not when their bills are paid. Return on investment is computed based on the difference between revenues and expenses, thus it too is computed concurrent with the services delivered since that is how the revenues and expenses are booked. When the cash flow from revenues and/or expenses does not occur simultaneously with recognition of the obligation, a cash working capital adjustment is necessary to ensure that the value of the actual cash return is equal to the allowed return on an accrual basis. Since all utility cash inflow from revenues lags the time of delivery[2], it is essential that the cash working capital allowance recognize the lag of <u>all</u> expenses that make up the revenue requirement regardless of the nature of these expenses. Some of these expenses are cash expenses with an associated lag. Others, such as depreciation, are accounting entries recorded as they accrue and have no lag.

Q. Does Mr. McCluskey accept this approach?

A. No, He is opposed to the inclusion of non-cash expenditures in cash working capital, arguing that cash working capital is limited to an allowance for the funds expended by stockholders for the lag between cash expenditures and the revenues allowed to support those expenses. He rationalizes that since depreciation is a non-cash expense, it cannot have a working capital requirement.

Q. What is wrong with his argument?

[2] Some utilities such as telephone, CATV and ISP's routinely bill for monthly services in advance of the service period. Even gas, electric and water utilities may have some minor revenues, such as rents, that are paid in advance. However, the large majority of gas, electric and water utility revenues lag their service period.

A. There is a theoretical flaw with his argument. As I will demonstrate, omitting these non-cash expenses will systematically deny the utility the opportunity to earn its allowed rate of return on a cash basis. The fact that these omitted items are non-cash expenses does not lessen the erosion of return.

Non-Cash Expenditures

Q. Explain the theoretical flaw you mentioned.

A. Gas utilities provide services to customers and then bill for those services after the fact. They must wait for customers to remit billed revenues after service has been provided and a bill has been issued. The utility's books, prepared on an accrual accounting basis, record the revenues when they are earned, i.e. when the sales are made, but the utility and its stockholders do not have use of these billed revenues (e.g., to pay dividends, reinvest in the business or pay expenses) at the time of billing since the funds are not available until they are received from customers. It is this revenue lag between making the sale and receiving the funds from customers that gives rise to the need for working capital, which is also why cash working capital must include the lag for receipt of <u>all</u> billed revenues.

Q. How does the exclusion of non-cash CWC impede the utility's ability to earn its authorized return?

A. To answer this question, we must first examine the utility's cash flow. The utility's revenue requirement includes reimbursement for operations expense and a reasonable return on investor-supplied capital including working capital. Because he is opposed to the inclusion of non-cash expenditures in cash working capital, Mr. McCluskey attempts to distinguish between portions of the revenue requirement that are based on cash expenditures and those that are based on non-cash activities. However, the cash working capital made available to the Company by its stockholders is not based solely on the portion of the Company's revenue requirement that stems from cash expenditures. Instead the cash working capital made available by investors is based on the lag in receipt of <u>all</u> of its earned revenues, offset by the delays experienced in the payment of all expenses. From the investor's perspective, it is not possible to distinguish between the lag in receipt of revenues from customers that is attributable to non-cash expenses from the lag attributable to cash expenses. The revenues lag in <u>total</u>, and stockholders must wait for those revenues.

As the Commission is aware, the calculation of cash working capital does not stop with the calculation of revenue lag because a utility's working capital needs are offset to some degree by the lag it also experiences in the payment of expenses. Using good cash management business practices, utilities generally pay bills when they are due and not before. As a result, they are able to husband some cash relating to sales previously made. The expenses shown on a company's books represent accrual of expenses for services provided to the utility. However, the cash payments for these expenses typically occur after the expenses are booked. The need for cash working capital is reduced by the cash provided through the lag in the payment of expenses.

Q. Are you saying that even depreciation, which is a non-cash expense should be included in the lead-lag study?

A. Yes. In arguing that depreciation should be excluded from the CWC calculation Mr. McCluskey fails to consider that the revenues intended to recover depreciation expense lag the service period and cause a need for cash working capital that is not offset by a corresponding expense lag precisely because depreciation is a non-cash expense. In other words, stockholders must wait to receive the revenues intended to compensate them for depreciation, but they experience no benefit from a delay in having to pay depreciation because it is a non-cash expense.

A more thorough answer is that depreciation expense is related to a <u>previous</u> cash expenditure made to acquire plant. In order to allow the proper return on investment, regulators allow both a return **on** investment and a return **of** investment. Depreciation is the return **of** investment. Accrual accounting practice makes it inappropriate to consider plant investment as an expense at the time it was made and instead establishes depreciation expense to distribute the expense related to the investment over its useful life. Therefore, depreciation expense can be considered as a series of cash expenses made throughout the useful life of the asset in lieu of expensing the initial plant investment all at one time. The matching principle calls for the expenses to be recorded in synch with the actual useful life of the facility.

Example of Impact of Non-Cash Expenditures

Q. Can you provide a more concrete, quantitative analysis to demonstrate this point?

A. Yes, the underlying purpose of a lead-lag study is to compute a cash working capital adjustment to rate base to account for the relative timing differences between revenues and expenses. The goal is to ensure that stockholders have a reasonable opportunity to earn the level of return on investment deemed appropriate by their regulators. That investment includes working capital. If revenues lag expenses, then stockholders must invest capital to support the utility's operations, or if expenses lag revenues, then the utility's operations provide a source of capital, thereby reducing the investment otherwise required from stockholders.

Attachment GLG-LL-4, presents a hypothetical gas distribution utility with a simplified capital structure to ease computation. The cost of capital in this example is half debt at 8% and half common equity at a cost of 12%. The effective income tax rate is 40%. At the end of year zero, the Company invests $1,000 in plant with a ten-year life and no salvage value.

The Company files a rate case immediately prior to each of the 11 years shown in this example, so that the rates in effect each year represent the current allowed rates in accordance with rate making precedent. In the first year, the Company's rates are set to recover operating and maintenance expenses, depreciation, taxes and return, as shown on line 11. For this simple example, operations or maintenance expenses are zero and there is no lag in the collection of revenues nor with the payment of expenses. The calculation of booked expenses is shown on lines 14 to 28, including an income tax calculation. As shown on lines 19 and 28, on an accrual basis the Company earns its overall rate of return and its authorized return on common equity.

Q. What are its earnings on a cash basis?

A. With no revenue or expense lag, you would expect the return on a cash basis to also equal the allowed return. The calculation of cash flow is shown on lines 30 to 38. In year zero, the utility makes a $1,000 investment in plant, as shown on line 36. In subsequent years, the Company's revenues, shown on line 31, are offset by its cash expenses on lines 32, 33 and 34. Since O&M expenses are assumed to be zero, and depreciation is a non-cash expense, income taxes are the only cash expense in this simplified example. Since the return is based on total stockholder investment, it does not include interest expense on debt. The net cash flow is shown on line 37, where negative figures are expenses and positive figures are income. Not coincidentally, the internal rate of return for this series of cash flows, shown on line 38, exactly matches the authorized overall return of 10.00%. Lines 41 to 50 develop the cash flows for yield on common equity. This calculation is similar to the Total Return calculation except that it includes the interest on bonds and the change in bond principal. The change in principal is computed each year as one-half the change in rate base and the interest is computed by applying the interest rate to the balance of debt outstanding. The net cash flows are shown on line 49, and the internal rate of return for this series of cash flows results in a return on equity of 12%, exactly the amount allowed.

Q. How does the inclusion of revenue lag impact the rate of return on a cash basis?

A. As you might expect, delaying only the revenues substantially reduces the rate of return on invested capital. As noted above, this is what occurs with depreciation, where there is a revenue lag because of the delay in receiving cash from customers paying their bills but no offsetting expense lag because depreciation is a non-cash expense. Attachment GLG-LL-5 shows the base case with one change – collection of revenues lag expenses by one year[3]. Since rates are set using booked revenues and expenses rather than actual cash flows, the Company's revenue

[3] In this hypothetical example, the use of a full year of lag rather than a few days exaggerates the impact of revenue lag experienced by utilities and, at the same time, greatly simplifies the calculations.

requirements are exactly the same as the base case. However, examining the cash flow analysis beginning on line 31 reveals that the delay in receiving revenues has lowered the overall rate of return to 6.77% and lowered the return on common equity to just 5.84%. Clearly, the existence of revenue lag alone will lower the rate of return below that allowed. In the absence of a rate base adjustment to account for this working capital, the stockholders will not be compensated for their invested funds.

Q. Will the inclusion of a rate base addition for cash working capital restore earnings to the targeted level?

A. In theory, a properly constructed adjustment will compensate stockholders for the delay in receipt of revenue so that the return on an accrual basis equals the return on a cash basis. The inclusion of a rate base addition for cash working capital can resolve this problem.

At the bottom of Attachment GLG-LL-5, I have shown ten lead-lag studies, one for each year when revenues lag expenses. If I employed Mr. McCluskey's recommended lead-lag study methods, the lead-lag study would exclude the revenue lag associated with depreciation and return on equity, so the first year lag would simply be the revenue lag associated with the cash expenses for taxes and interest. Since there is no lag with either taxes or interest, the CWC adjustment would be $0. On the other hand, using the method I recommend, all revenue lag would be included.

In Attachment GLG-LL-6, I have demonstrated my approach. The lead-lag study in this hypothetical is quite simple. All revenues lag by one year and no expenses have any lag, so the first year CWC addition, as shown on line 64 is $240. This method is comparable to that used to create Attachment GLG-LL-3.

Q. Did the CWC adjustment to rate base of $240 equalize the rate of return on both an accrual and cash basis.

A. Not completely. As shown in the cash flow analyses in Attachment GLG-LL-6, overall return has increased to 8.93% (line 38) and return on common equity has increased to 10.86%, thereby alleviating some, but not all, of the earnings erosion due to revenue lag. If the CWC had been zero, using Mr. McCluskey's methodology, the return on a cash basis would be far short of that allowed. Consequently, it is obvious that Mr. McCluskey's approach does not compensate investors and is, therefore, confiscatory.

Q. Why was the $240 CWC adjustment insufficient?

A. The internal rates of return developed on Attachment GLG-LL-6 do not match the allowed returns due to the effects of compounding. The cash working capital allowance was based on the revenue requirements shown on Attachment GLG-LL-4. However, those revenue requirements exclude the additional revenues associated with the CWC addition to rate base. A more accurate CWC calculation requires inclusion of the revenue impact of the rate base adjustment. In essence, the CWC must be calculated using the pro forma revenue requirement. If the CWC calculation is not made on the basis of approved revenues, including the CWC adjustment, the CWC adjustment will be insufficient. That is why I recommend that the lead-lag study should be updated at the conclusion of the case to include the final revenue requirement approved by the Commission in this docket.

Q. Did you make this final iteration in your hypothetical example?

A. Yes, the improved calculation is shown at the bottom of Attachment GLG-LL-7. On this exhibit, the first year's lead-lag study suggests a CWC adjustment of $279.07, not the $240.00 originally used. Attachment GLG-LL-7 shows the impact of compounding. Using a CWC addition of $279.07 properly reflects the level of CWC necessary to reflect the full impact of the revenue lag. In this case, the lead-lag study demonstrates this fact, i.e. each year's rate base addition exactly matches the lead-lag study's indicated CWC. Including this level of CWC generates a total return on rate base of 9.26% and a return on common equity of 10.86%. While both of these figures still fall below the level authorized, they represent a marked improvement. The remaining difference between achieved and targeted return is the result of regulatory lag. Theoretically, rate relief from including the CWC should be immediate and generate additional cash flow beginning in the first year. However, in this exaggerated example, the rate relief is delayed a full year. If the additional revenues of $39.07 ($279.07 – $240.00) were received in cash in the first year, instead of delayed until the second year, the return would have increased to 10%. If the net lag were in a more normal range of a few days instead of a whole year, the mismatch between allowed and achieved rates of return would be much smaller.

Return on Equity in Lead-Lag Study

Q. Mr. McCluskey also recommended the exclusion of return on equity from the lead-lag study. Can you use your hypothetical model to examine the effect of excluding return on equity?

A. Yes, on Attachment GLG-LL-8, I have modified the previous attachment to exclude return on equity from the lead-lag study. In this instance, the revenue lag on line 54 excludes the return on equity shown on line 27. As you might expect, reducing the CWC reduces the return and causes the earned return to fall short of the allowed level on a cash basis. From this we can conclude that Mr. McCluskey's adjustment is inappropriate. For the reasons I have already discussed, the CWC allowance must include the lag of <u>all</u> revenues received from customers (i.e., all of the items included in the revenue requirement, including the non-cash items such as depreciation and return).

Q. What can you conclude from your analyses?

A. The lead-lag study essentially measures the stockholders' net investment in accounts receivable as compared with accounts payable. The difference between the two is the investment needed to bridge the gap, which is referred to as working capital. What is important to note is that an increase in the balance of accounts receivable represents a use of funds, not a source of funds. Therefore, an increase in accounts receivable has an adverse effect on cash flow. When revenues are billed and accounts receivable increased, there is an implicit investment by shareholders who must make additional cash available to bridge the gap. All of the billed revenues have this effect, regardless of the underlying components of the revenue requirement which gives rise to the rates that that led to those revenues.

Q. Can you offer a different vantage point to examine the proper content of a lead-lag study?

A. Yes, there is another way to view the question of cash working capital. If regulatory practice employs accrual accounting, then the computation of cash working capital seeks to capture the net investment in accounts receivable versus accounts payable. Every component of the revenue requirement, including non-cash items and return, is part of the accounts receivable balance that is included in rates and billed to customers. Consistency and fairness dictate that we cannot pick and choose which components of the revenue requirement are going to be measured on a cash basis and which are to be measured on an accrual basis. It would be wrong to reduce rate base for non-cash items such as accumulated depreciation and accumulated deferred income taxes on an accrual basis while, at the same time, measuring the working capital component of rate base on a cash basis.

Consistency with North Carolina Filing

Q. Staff argues that the use of a zero lag for uncollectible accounts expense in this study is inconsistent with a recent study you submitted on behalf of Piedmont Natural Gas Company before the North Carolina Utilities Commission ("NCUC"). Is he correct?

A. No, the facts and circumstances of that case and this one are quite different. In the Piedmont case, NCUC Docket G-9, Sub 550, I did not advocate the method I would normally recommend. Instead, I followed established NCUC lead-lag study precedent to calculate the uncollectible accounts expense lag. By following a method established by precedent, I was not advocating that method. I was simply complying with the requirements of the particular regulatory agency regarding where the study was filed. Therefore, Mr. McClusky's concerns about consistent calculations between different regulatory jurisdictions is misplaced. In my direct testimony, I explained the reasons that using a zero lag for uncollectible accounts expense is appropriate, and I will not repeat those arguments here. I should note that, in much the same manner, my study in this case incorporated a calculation that was dictated by a prior decision (in Docket DG 07-050) rather than my own preference.[4]

Treatment of Below-the-Line Items

Q. Mr. McCluskey also argues that below-the-line items such as return should be completely removed from the lead-lag study. Do you agree with his argument?

A. No. In Attachment GLG-LL-8, I have demonstrated that the exclusion of return in the lead-lag study is inappropriate, However, even if we were to accept Mr. McCluskey's premise, his computations are inconsistent with his recommendations. On page 12 of his direct testimony, he objects to avoiding uncompensated use of below-the-line funds. Later on the same page, he references FERC precedent, which he believes supports his position, but he fails to reflect the correct impact of the FERC order in his CWC calculations. The cited FERC order states:

> The lead/lag study has reduced the lag in paying operating and maintenance expenses to reflect the availability of funds to pay interest on long-term debt and dividends on preferred

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[4] Rather than advocate a specific method of computing collection lag, I have adopted the precedent established by the NHPUC when it approved the partial settlement agreement in Docket Number DG 07-050.

> and common stock. In Florida Gas Transmission Company (Opinion No. 611, 47 FPC 341, 356 (1972), reh denied, Opinion No. 611-A, 49 FPC 261 (1973)) the Commission rejected the use of interest on long-term (debt) in determining a utility's cash working capital allowance on the ground that such interest is not an operating or cost-of-service expense but a below-the-line item. The Commission reasoned that as a matter of policy these funds belonged to the utility and its shareholders so that a utility could not be expected to use them as working capital without remuneration.

To paraphrase the order, the FERC is suggesting that shareholders should be compensated if below-the-line items are included in the lead-lag study, which is the approach I have advocated. The FERC chose not to compensate shareholders for the revenue lag in recovering return and therefore, for consistency, excluded *both* interest on debt and return on equity in their lead-lag study. Mr. McCluskey misapplies this precedent and chooses to include interest on debt but excludes return in his proposed CWC calculation. The effect of these selections is to reduce the CWC adjustment to rate base. Had he included both or excluded both, his computed CWC would have been greater. His method is inconsistent because it provides customers with the benefit of the long lag in paying debt, but does not include a similar treatment for equity. The CWC disallowance proposed by Mr. McCluskey resulting from the exclusion of return alone was $618,117, and including debt reduced the CWC by an additional disallowance of $247,573.

Q. Do you agree with Mr. McCluskey's conclusion that short term debt ("STD") should have a 45 day lead?

A. No, but admittedly this is a very complex question. I would agree with Mr. McCluskey if the amount of short term interest expense allowed in the revenue requirement calculation were based on the actual amount of interest paid, but it is not. In determining the revenue requirement associated with short-term debt, the nominal short term interest rate is multiplied by the portion of rate base funded with STD. That level of interest expense would only occur if the utility paid the interest expense with no lag. In actuality, the utility pays the interest expense sometime after the accrual period. As a result, additional interest expense is incurred between the original accrual period and the payment date and that interest is paid at a later date, much the way a debtor accrues additional interest expense on a home equity loan between the time the bank issues a bill for the interest accrued in a given billing period and the date the bill is actually paid. This additional interest expense is not included in the revenue requirement. The use of zero lag for interest on STD is essential to be consistent with the level of interest expense included in the revenue requirements.

Q. Why is it appropriate to include the 91.25 day lag on interest on long term debt and then ignore the 45 day lag on short term debt payments?

A. This treatment is necessary to maintain consistency with the treatment of debt in the revenue requirement calculations. In both cases interest is computed using the nominal interest rate. In the case of long term debt, the actual interest payments are based on the nominal rate and are made 91.25 days beyond the midpoint of the accrual period. However, unlike short term debt, no additional interest is accrued between the accrual period and the payment date. Therefore, unlike for STD, the revenue requirement for long term debt reflects the actual interest paid. As a result, until the interest payments are made, they serve as a free source of cash that can be used to support operations and must be included in the lead-lag study.

The case for short term debt is similar with one exception, the interest payment held between the accrual period and the payment date is not free; it is accruing additional interest that is not included in the revenue requirement. The stockholders pay this interest without compensation, unless the lag for the interest is set to zero in the Lead-Lag study[5].

Staff's Adjustment to Decreased Collection Lag

Q. Do you concur with Mr. McCluskey's 2.0 day decrease to collection lag?

[5] Alternatives would be to include the additional interest expense or to adjust the nominal interest rate upward to reflect the additional interest paid in the revenue requirements calculation.

A. No, I do not agree.

Q. Why not?

A. Mr. McCluskey simply assumes that the Company's revenue collection performance has declined, even though he recognizes that many factors affect collection performance, including unemployment levels, income levels, urban population concentration, meter accessibility issues, sales growth and commodity price increases. Because the Company could not provide all of the data that he would have liked to have had in Docket DG 07-050 in order to complete his analysis, Mr. McCluskey made the assumption that the Company's performance was entirely responsible for the increases in both accounts receivable balances and write-off rates, yet there is strong evidence that this simply is not the case. In Docket No. DG 07-050, Mr. McCluskey computed the collection lag for 2005 as 38.75 days[6]. Yet for 2007, the collection lag fell to 34.96 days, using the same accounts turnover method recommended by Staff. Certainly, this is an indication of an improvement in overall collection performance. However, there is no evidence to conclude which factor or factors contributed to this improvement. Having decided that the Company had caused the decline in collections performance, Mr. McCluskey then reduced the collection lag by two days, but provided no basis for such a reduction.

[6] Source: Docket No. DG 07-050, Joint Surrebuttal Testimony of Amanda O. Noonan and George R. McCluskey, Staff Exhibit-8.

Q. If the Commission adopts a lead-lag study methodology that includes debt or equity in its calculation, should the lead-lag study be revised as part of the Commission's final order in this proceeding?

A. From a practical standpoint, adjusting the lead-lag study to reflect the allowed level of income taxes and return would be cumbersome at best. However, theoretically, such an adjustment is appropriate. The need stems from the fact that the CWC calculation shown on Attachment GLG-LL-3 employed the Company's pro-forma revenue requirements before increasing return and taxes to the requested levels. Consequently, the lags associated with these revenue requirement components significantly understate the requested return. I recommend that the final order adjust the return and taxes in the lead-lag study to reflect the allowed levels.

MARGINAL COST STUDY

Rebuttal of Staff Adjustments

Q. Mr. McCluskey's direct testimony recommended four corrections to the marginal cost study. These corrections relate to (a) contributions in aid of construction; (b) regression techniques for projected main reinforcements; (c) meter spares; and (d)

uncollectible accounts expense. Please discuss the first of Mr. McCluskey's recommended revisions to the marginal cost study.

A. Staff erroneously concludes that the use of historical mains investment data net of customer contributions understates marginal costs. If utility companies had no requirements for customer contributions, he would be correct. However, that is not the case. The filed marginal cost study represents the utility's marginal costs, not society's marginal costs. The purpose of customer contributions is to avoid utility expenditures for un-economic expansion. By using data net of contributions, we measure the cost the utility must incur to expand capacity on the system. If we were to base the MCS calculations on gross costs, before reducing it for payments required from customers, we would develop much higher marginal costs that would not be representative of the marginal costs the utility would incur to serve additional load. In my experience, no utilities employ gross plant additions as the basis for calculating marginal distribution costs.

Q. What is Staff's second proposed adjustment to the MCS?

A. Staff believes the regression used to estimate distribution capacity reinforcement costs is inappropriate. The data consists of forecasted annual estimates of reinforcement costs provided by the Company's distribution planning personnel. Estimates are provided for each of the first six years as well as an estimate for the total reinforcements expected over the next four years. Mr. McCluskey states:

> Combining annual and multi-year data in this way is inappropriate because it results in a different regression coefficient and, hence, a different marginal reinforcement cost[7].

I disagree. Utility planners do not have a crystal ball. Based on historical data, system planners and their software can make some realistic estimates as to where load growth might occur in the immediate future and use that to estimate which facilities must be reinforced. However, accurate year-by-year projections many years into the future are not feasible. Conducting annual studies far into the future would not improve the accuracy of the forecasts. Annual studies beyond five years would simply be a waste of resources. This is the reason why planners typically employ multi-year forecasts beyond five years. If individual studies had been completed for each year in the planning horizon, the least-squares regression technique would weight them equally. However, logic would argue that the early years should be weighted more heavily because they are likely to be more accurate than the later years. Thus, the use of individual year data, as Staff recommended, would be improper based on the available data.

As an exercise, I assumed that the reinforcement costs and the load growth over years seven to ten were equal each year and reran the regression using the assumed data points for each individual year. The resulting estimate of reinforcement cost was 11% higher. In total, distribution capacity related investment, the sum of reinforcements and

[7] McCluskey Direct Testimony, page 34, line 8-11.

extensions, increased by 2% and marginal unit costs, including O&M expenses, increased 1%. Therefore, even if individual data points had been used for years seven through ten, the impact would be minimal. The individual data points were deliberately not used resulting in a slightly more accurate estimate of marginal costs.

Q. What was Staff's third criticism of the marginal cost study?

A. In the computation of marginal meter investment, I included an adjustment for inactive and spare meters. Staff erroneously opined that this adjustment was unnecessary. Marginal customer costs are measured on a per customer basis, not on a per meter basis. Admittedly, when the utility adds an active customer, they immediately add one and only one meter[8]. The Company cannot predict whether this customer will become inactive, as is the case with some customers. In the same vein, on average, the utility must always maintain some level of spare meters. So when examining the costs the utility will incur to add a customer, the long run estimate must include an allowance for meters that will be inactive or spare. Put differently, marginal customer costs can be measured as the first derivative of the customer costs with respect to customers. The customer costs include active, inactive and spare meters, such that, in the long run, the change in customer costs for an increment of one customer cannot exclude the costs of inactive meters or spares as the Staff has suggested.

[8] This point ignores the limited number of very large customers with more than one meter.

Q. What was Staff's fourth criticism of the MCS?

A. Staff's fourth criticism was its claim that uncollectible accounts expense is not a marginal cost because, according to Mr. McCluskey, the cost to meet the demand of a new customer is independent of whether that customer pays his or her bill on time or at all. The question boils down to this: Will the utility recover its marginal costs if its charges are not adjusted for an increase in uncollectible accounts resulting from an increase in the number of customers served? Obviously not, because some new customers ultimately will not pay their bills. For this reason, all marginal cost studies I have ever encountered have included an adjustment for uncollectible accounts expense. These studies include all of the marginal cost studies previously filed by my colleague Mr. Harrison for ENGI, Northern Utilities and Unitil Energy Services and used to support rate designs accepted by the NHPUC.

Q. Mr. McCluskey claims that Mr. Harrison, filed an MCS in Docket DE 05-178 that excluded uncollectible accounts expense. Is that true?

A. No. An excerpt from the MCS submitted as part of a Unitil compliance filing in that docket is attached to my testimony as Attachment GLG-RD-6. As that excerpt shows, the Unitil MCS study <u>included</u> uncollectible accounts expense entirely as a customer cost, by including the uncollectible accounts expense in Account 904 along with all other customer accounting expenses. Mr. McCluskey acknowledged his error in response to a Company data request in this case.

Q. What was Mr. McCluskey's ultimate recommendation regarding National Grid NH's marginal cost study?

A. On page 26, lines 10-12, of his direct testimony, Mr. McCluskey states

> Despite several errors in the calculation of marginal capacity and customer costs, I believe the results of Mr. Goble's marginal cost study provide sufficient support for changing rate class revenue requirements and re-designing rates.

Although I disagree with Mr. McCluskey regarding his reference to errors in calculation, I certainly do agree with his ultimate recommendation, which is to employ the results of the marginal cost study in setting rate class revenue distributions and in rate design.

Rebuttal of OCA Position

Q. Please summarize the OCA's criticisms of your MCS.

A. The OCA identified four alleged "errors" in the filed MCS:

1. The MCS does not reflect the proposed revision to the policy for Contributions in aid of Construction (CIAC),
2. The MCS draws an improper conclusion in estimating capacity-related operating expenses when the regression results are insignificant,

3. The MCS should exclude Non-plant Administrative and General expense loading factor, and
4. The MCS improperly assigns a portion of expenses incurred to operate distribution lines to the customer component.

Q. Do you agree with the OCA's first point regarding CIAC?

A. Yes, I agree that the MCS determines the test year marginal costs based on the CIAC policy that was in effect during the test year. If the NHPUC adopts the Company's proposed policy change for main extensions, the compliance MCS should be modified to reflect the new policy. The compliance MCS would reflect the changes demonstrated to all parties in the response filed by the Company to OCA's Data Request 3-15.

Q. Do you agree with the second point, that you have underestimated capacity-related expenses?

A. No, I do not. A review of the unit cost data for the capacity-related operating and maintenance expenses on Table 5 of the marginal cost study reveals no underlying trend, an absence of causal relationship borne out by the lack of a significant statistical correlation. This is to be expected since the operation of the Company and its accounting for some costs changed significantly with the KeySpan/Eastern Enterprises/EnergyNorth merger and the subsequent conversion from the SAP to Oracle accounting system. Unit costs decreased dramatically to an 18 year low in 2001 followed the very next year by the record high unit cost. The use of the 2002 to 2006 average employed in the filed study utilizes all of the available data consistently developed from the Oracle accounting system. The OCA's suggestion that this figure is overstated and that the Company can somehow revert back to the pre-merger levels of cost is not realistic and does not reflect the marginal costs the Company faces. OCA's suggestion that the data for the years 1999 to 2002 should be removed lacks any fundamental rationale. This period includes some pre- and some post-merger years. Data should not be arbitrarily removed or ignored as the OCA suggests simply because it is lower than average.

Q. Please comment on the OCA's third point that the use of a Non-plant A&G Loading factor is inappropriate.

A. The OCA argues that the estimate for this loading factor is too large. Pre-merger, when operated as a stand-alone utility and utilizing the SAP accounting system, the Company's A&G expenses were generally lower than the post-merger period and included roughly $1 million per year for rent and general plant maintenance that were eliminated in the post-merger era. The loading factor prior to the merger varied in a relatively narrow range from 35% to 45%. Post-merger the loading factor has varied from 48% to 125%. This increased loading factor stems from the fact that, after the merger, the service company performs functions previously performed by the Company itself. Those functions are now billed to the Company by the service company and recorded as an A&G expense. As a result, the pre-merger A&G expense data is meaningless to the estimation of marginal costs. Similarly, the data for 2001 and 2002 should be eliminated due to the anomalies associated with the merger accounting and the conversion and implementation of the Oracle accounting system. The filed study uses the average of the most recent four years to estimate the loading factor at 66%. The OCA argues that the most recent two years are much lower and are more representative of the future. The truth is that the recent merger with National Grid may have further implications to the A&G loading factor that are not yet apparent. There is simply no "bullet proof" basis for estimating the loading factor. While every utility is different, I have observed that a 66% loading factor is well within the range of reasonableness. It is rare to see these loading factors below 50% or over 100%. Based on my experience and the variability of the data, I chose to use the four years of valid data. Making such judgments is a necessary part of performing an MCS.

Q. Please comment on the OCA's last point that operating expenses for underground lines should be assigned exclusively to the capacity component and none should be assigned to the customer component.

A. The Uniform System of Accounts, as implemented by the FERC, defines Account 874, Mains and Services as shown on Attachment GLG-RD-7.

Specifically, these costs include labor, materials and expenses incurred in operating mains <u>and services</u>. MAC has routinely assigned a portion of this account to the customer component in every gas marginal cost study it has performed. Contrary to the OCA's assertion that these expenses rarely, if ever, pertain to services, it is costly to operate services. As a prime example, the utility routinely incurs costs to mark the location of customers' services prior to any digging activities. A review of the expenses included in Account 874 reveals that about two thirds of the costs booked in this account are related to markouts. The OCA's conclusion that none of these expenses should be assigned to the customer component is simply incorrect.

Q. Aside from the errors the OCA claims were made in the MCS, the OCA argues that the MCS is inappropriate for the design of rates and that an embedded cost of service study is more appropriate. Could you summarize OCA's arguments?

A. The OCA chooses to revisit a topic that has already been vigorously reviewed by all parties and addressed by the NHPUC on multiple occasions. The NHPUC investigated ratemaking methodologies in a generic docket over twenty years ago[9]. The use of marginal cost studies has been endorsed by the NHPUC for both the establishment of class revenue targets and the design of the rates themselves. The NHPUC rejected the use of an accounting cost study in Docket Nos. DE 86-208

[9] NHPUC Order No. 9,255, Docket No. DE 86-208, Gas Rate Design Investigation, June 24, 1988.

and DR 90-183. It reaffirmed the use of marginal costs to establish class revenue allocations in Docket Nos. DR 91-081, DR 91-149 and DG 00-063. The OCA's conclusion that the absence of an embedded cost study justifies ignoring the results of the MCS and adjusting all rates equally across the board is illogical and unreasonable. Throughout its testimony the OCA refers to "actual costs," referring to the costs resulting from an embedded cost of service study. OCA argues that the MCS results are inappropriate because they differ from the "actual" revenue requirements. It is not surprising that these costs are different. They should be. In fact, it is exactly the differences between the costs derived under an MCS versus an embedded cost study that led the NHPUC to choose marginal over embedded cost studies as the basis for class revenue allocations.

Q. Please comment on the OCA's arguments about economic efficiency.

A. The OCA concludes that the use of marginal costs reconciled to allowed revenues using the equi-proportional method, as filed by the Company, will not result in economic efficiency. The arguments put forth by the OCA's witnesses are not new. In Docket No. DE 86-208, the OCA argued for the use of an accounting cost of service study to allocate class revenue requirements[10]. If marginal costs were to be employed, the OCA argued, the method of reconciliation should be established in the utility's next

[10] NHPUC Order No. 19,255 (Dkt. DE 86-208), which incorporated a document entitled Report of the Gas Rate Design Investigation (June 24, 1988), Attachment 8 of which was an OCA Position Paper on Revenue Reconciliation.

general rate case. In the Company's general rate case, contrary to the OCA's position, the equi-proportional method was used to adjust marginal costs to establish class revenue allocations. This same method was employed in Northern Utilities' next rate case, Docket No. DR 91-091, and in Public Service of New Hampshire's rate case[11]. The fact remains that pricing at unadjusted marginal costs will never generate the revenues allowed under conventional rate of return rate making. Some form of adjustment will always be necessary.

There are two commonly used approaches to adjust marginal costs so that resulting revenues match allowed - the Inverse Elasticity method, also known as Ramsey Pricing, and the Equi-proportional method. In Docket No. DE 86-208, both Staff and the OCA recognized that the implementation of the Inverse Elasticity method requires price elasticity information that is simply not available. Staff recommended the use of the Equi-proportional method[12]. Consequently, all filings before the NHPUC have employed the use of the Equi-proportional adjustment method. Nonetheless, the OCA argues that accurate pricing of capacity-related delivery costs, what the OCA witnesses refer to as "marginal delivery cost," is more important than pricing of customer-related delivery costs[13]. The OCA points out that the proposed prices for capacity-related delivery services are lower than the unadjusted marginal costs and claims that

[11] NHPUC Order No. 20,504.
[12] NHPUC Order No. 19,255 (Dkt. DE 86-208), which incorporated Report of the Gas Rate Design Investigation (June 24, 1988), Attachment 5 of which was a document entitled Staff Position Paper on Revenue Reconciliation.
[13] Direct Testimony of Smith/Freitas, page 17.

such pricing will not enhance economic efficiency. As best I can determine, Mr. Freitas is advocating the use of the Inverse Elasticity method to adjust marginal costs, though these words never appear directly in his testimony. However, he never provides a logical basis for his conclusions nor presents a different set of marginal costs upon which to base rate design. Absent this information, there is no basis to reject the method of rate design advocated by both the Company and Staff.

Q. Please summarize the OCA's arguments concerning cost allocation.

A. The OCA has recommended the use of an embedded cost of service study. These studies take a top down approach beginning with revenue requirements and allocating costs to serve to customer classes typically using many different allocation methods. Allocation is inherently a top down approach. The OCA claims that the MCS is flawed because it only uses two allocation factors, design day demand and customers.

Q. Do you agree?

A. No, the OCA's argument is based on a mischaracterization of how marginal cost studies are performed. The MCS is a bottom up procedure developing system wide unit cost data and then multiplying those unit costs by individual classes' billing units to develop total marginal costs. Allocation techniques are not employed in an MCS. Instead, system unit cost data is examined to determine what causes a particular cost or set of costs to increase.

Distribution mains provide a good example of this. Once in place, these mains represent a sunk, rather than a marginal, cost. The existing mains can serve all loads, unless those loads exceed the mains' existing load carrying capacity. System planners recognize that the distribution system's capacity must be sized to meet the customers' design day loads. Thus, expansion of the existing mains is only necessary to serve loads that exceed the currently established level of design day demand. For this reason, the MCS study measures mains investment in terms of design day demand unit costs. No other "allocation factor" is necessary to accurately ascribe the system's unit costs.

Q. Do you agree with the OCA that main extensions to serve new load are driven by expected customer volumes rather than by design day demands?

A. No. The utility will perform a revenue test to determine that expected revenues are sufficient to justify a main extension investment, and revenues are driven primarily by customer sales volumes. Therefore, the OCA concludes that main extension costs are attributable to sales volumes. The problem with this logic is that it is circular - main extension investment is driven by revenues and revenues are driven by prices. Therefore, if prices are based on sales volumes, then sales volumes drive main extension investment. However, if prices were based on design day demands, as indicated by the marginal cost study, then revenues would be based on design day demands, which in turn, would drive main extension investment.

Q. The OCA argues that the implementation of MCS pricing overstates the customer costs to existing customers. Do you agree?

A. No, the OCA's argument has been discredited on a number of occasions in the past. OCA argues that the sunk costs for installing existing services and meters are markedly lower than the costs to serve new customers. The OCA witnesses ignore the fact that, although the costs for the existing service line and meter are sunk, the costs for the replacement service and meter are not. The decision to continue as a customer will result in future service and meter investments. Obviously, the customer does not pay for his or her replacement equipment on a lump sum basis; the Company must make this investment.

Q. What is the annualized cost required to fund the ongoing replacement of existing equipment?

A. The annualized cost required to fund the ongoing life-cycle replacement of existing equipment is calculated using an economist's fixed charge rate. The economist's fixed charge rate used in the marginal cost study levelizes one-time investments such as the service or meter replacement referred to above. The economist's fixed charge rate, unlike a conventional fixed rate mortgage, generates a series of annual payments over the life of an asset that escalate each year with inflation, so that the payments are equal in constant year dollars. At the end of the asset's useful life (and assuming the replacement cost has increased by the same rate of inflation), the levelized payment for the new asset will exactly equal the levelized payment for the old asset in constant dollars. The annual stream of payments beginning in the test year necessary to fund the replacement line transformer (or meter or service) over its expected useful lifetime is exactly the same as the amount developed in the marginal cost study for new line transformers (or meters or services). Therefore, the annualized marginal costs imposed by new as well as existing customers, when stated as a series of payments escalating with inflation, are the same. The service and meter costs for new customers are no different than the costs for existing customers over the long run. Therefore, the OCA's argument distinguishing the costs between new customers and existing customers is a distinction without a difference. The OCA's recommendations are flawed and do not reflect the calculations in the Company's marginal cost study.

RATE DESIGN

Q. Please summarize the rate design process proposed by OCA witnesses Smith and Freitas.

A. The OCA witnesses claim that it is neither fair nor reasonable to use the results of the marginal cost study to design rates. They divide the rate design process into two steps, establishing the revenue targets for each class and then designing the specific rates. They reject the use of marginal costs to establish class revenue targets. They also reject the use of the marginal cost study for establishing customer charges, but they endorse the concept of using the capacity-related portion of delivery marginal costs to establish pricing for incremental usage. Since the OCA witnesses reject the use of marginal costs to establish revenue targets, in the absence of an embedded cost study they find no basis for changing the revenue targets among classes and endorse an equal percentage adjustment. As for the actual rate design, the OCA witnesses argue that using the results of the Company's marginal cost study would move away from efficient pricing, and, therefore, the rate designs for each class should also be made on an equal percentage basis.

Rebuttal of OCA Rate Design Argument

Q. Do you find the OCA's arguments concerning the establishment of revenue targets compelling?

A. No. The OCA's testimony is vague and over-generalizes to draw its conclusions. OCA makes several references to "actual costs", by which I believe the witnesses mean allocated costs using embedded cost allocation methods. Without ever using the terms, the OCA witnesses attempt to discredit the calculation of revenue targets because marginal costs are reconciled to allowed revenues using the Equi-proportional Adjustment Mechanism. They do not acknowledge what most economists and the NHPUC have already concluded - that the best solution for efficient rate making is to use marginal costs without reconciliation to allowed levels. However, given that revenue reconciliation is ultimately necessary, the "second best" solution is to adjust marginal costs rather than simply abandon them. To my knowledge, marginal costs adjusted using the equi-proportional method have been employed for rate design in every gas and electric rate filed before the NHPUC for the past twenty years, so I find it hard to accept the OCA's conclusion that this method is not valid.

Q. Can you comment on the OCA's specific rate design recommendation?

A. The OCA appears to recommend that marginal costs should have no role in designing rates other than designing tail block rates -- and then only if marginal costs are not adjusted to allowed revenue levels. Theoretically, this position appears to endorse the same results that would occur if the

Inverse Elasticity Method were used to reconcile marginal costs and if some heroic assumptions were made in the absence of necessary price elasticity data - namely that the price elasticity of customer charges is zero. This position is untenable for two reasons: the NHPUC has never endorsed the Inverse Elasticity method, and the price elasticity data to draw the OCA's conclusions simply does not exist. The OCA's recommendation to use an equal percentage increase must be recognized for what it is – an attempt to delay movement toward more efficient cost based price signals.

Rebuttal of Staff Rate Design Proposal

Q. What is the rate design proposal of the Staff?

A. Mr. McCluskey generally endorsed the Company's methods to establish class revenue targets[14], but he took exception to the bill impacts for small users and recommended capping the increase to the customer charge and eliminating the present block rate structure.

Q. Staff appears to argue that the fixed, capacity-related costs in your MCS should be collected through a volumetric charge while you have advocated that they should be rolled into a fixed monthly facilities charge. Could you comment on this issue?

[14] He suggests that rate relief for the G-51 and G-52 classes may be desirable if the overall increase granted to the Company is substantially smaller than requests. (McCluskey Direct Testimony, page 28)

A. Utilities offering local phone service, internet access, cable TV service and even cell phone service are similar to gas utilities in many respects. They all incur high fixed costs to provide capacity to customers at time of peak and that capacity is seldom, if ever, fully utilized. Costs are incurred to have capacity available at times of peak, regardless of whether the customer actually uses it at that time. These other utilities recover the large majority of their costs through fixed monthly fees. In the telephone industry, message unit billing is feasible for residential customers, though the approach is rarely employed. In the internet access market, most providers initially priced on the basis of connected minutes, but the market has shifted, resulting in virtually all carriers offering unlimited usage for a flat monthly fee as their most popular plan. Note that cell phone service plans often allow unlimited usage in off peak periods. Such unlimited off-peak pricing plans are consistent with the fact that marginal capacity costs are zero in off peak periods. Furthermore, many telephone pricing plans bundle a large number of peak period minutes for a fixed monthly fee. The various cell telephone pricing plans have a direct analogy to the gas utility industry. The plan groupings are analogous to the utility's rate classes - large plan users are similar to large commercial and industrial users, both desiring a commitment of capacity. Conversely, small plans are similar to residential users. Even though the cell phone usage among customers signed up for low usage vary, they all pay the same minimum monthly fee.

Staff would have most of these capacity costs recovered volumetrically as they have in the past. The price signal to customers is just plain wrong. Under Staff's approach, revenues are derived from usage throughout the year, for example, in the summer and on warm winter days. In contrast, the marginal cost study shows that usage in these time periods[15] has no effect on costs. Customers are simply using the capacity that exists from sunk investments. Volumetric charges are appropriate for pricing supply service, but not delivery service.

Q. Do the level of customer charges affect other rate design goals?

A. Yes, one goal identified by both Staff and the OCA is conservation. As discussed in the direct testimony of Mr. Stavropoulos, a revenue decoupling mechanism would align the interest of the Company and the consumer to encourage conservation. The level of customer charges established in this case will have a major impact on the effectiveness of rate design decoupling mechanisms and their ability to encourage conservation, if the Commission chooses to implement such a mechanism in the future.

Q. Please briefly describe revenue decoupling and how customer charges can affect revenue decoupling.

A. With the increase in gas commodity costs, price elasticity effects have resulted in customer conservation efforts, as they should. However, the

[15] All loads except those that occur on the design day are irrelevant to marginal capacity costs.

trend in declining use per customer has a deleterious effect on utility earnings that is exacerbated by the fact that the use of historical test year revenues does not reflect the impact of the reduced revenues that the utility is likely to experience when new rates go into effect. As a result, utilities are unintentionally incentivized to discourage conservation. If capacity-related costs are recovered through the customer charge as I recommend, then the need for revenue decoupling could become less pressing.

Q. Must the NHPUC resolve this issue now?

A. While it may be desirable to provide direction on this issue in the form of precedent, it is not necessary to do so in this docket. The method of charging capacity-related delivery costs need not be an issue at this time because the majority of current customer charges are not recovering all customer costs, let alone capacity costs. As an example, the marginal customer cost to serve residential heating customers is about $30 per month and the current customer charge is less than $10. As long as customer charges are set below customer costs, all capacity-related costs will continue to be collected volumetrically. It is unlikely that the residential customer charge will be set above $30 per month in this case, so the method of recovering capacity-related costs will continue to be collected on the basis of therm charges.

Q. Please comment on Staff's recommended cap for customer charge increases

A. Mr. McCluskey has recommended that customer increases should be capped at 200% of the increase granted to the rate class. In the case of customers with zero use (only billed a customer charge), the customer charge increase cannot exceed 200% of the class's overall rate increase. Under this approach, little movement toward cost based rates is possible if the class's revenue target increase is small. Using Staff's approach, a class receiving a 1% increase would be limited to a customer charge increase of only 2%. The combination of a 125% class revenue cap and a 2X customer charge cap would have the effect of forestalling accurate pricing. Under these restrictive assumptions, customer charges would continue to be less than customer costs <u>for at least 50 years</u>. If the NHPUC agreed that capacity costs should eventually be recovered as a fixed monthly fee and impose Mr. McCluskey's caps for percentage increases to class revenues and customer charges, it would take <u>over 250 years</u> to achieve the goal. While I agree that gradualism has a legitimate role in rate design, I believe that the 200% proposed customer charge cap is unduly restrictive and provides very little movement toward prices that recover their associated marginal costs.

Q. Please comment on Staff's suggestion to implement flat rate pricing.

A. Flat rate pricing offers simplicity as its primary advantage. However, it has some disadvantages, as well. Coupled with the customer charge cap that he has proposed, Mr. McCluskey's flat rate would increase volumetric charges, which would discourage greater gas consumption, as he stated. However, the therm charges would exceed marginal costs and would not be efficient in an economic sense. Flat rates would encourage conservation of delivery services, when economics tells us the opposite. The supply charges (which constitute approximately 70% of a customer's bills) provide customers with the price signal to conserve. More importantly, recall that the declining block rate structure collects customer costs not already recovered in the customer charge. For example, the head block generates over seven dollars per month for a larger than average residential heating customer under the present rates. Eliminating the head block and moving to a flat rate design would increase the variability of customer bills, increase intra-class rate subsidization, exacerbate revenue decoupling and move rates further away from marginal costs to serve. I do not recommend that we move in this direction.

SUMMARY

Q. Please summarize your rebuttal of Staff witness McClusky's testimony.

A. My rebuttal testimony addresses Staff witness McClusky's issues relating to the lead-lag study and cash working capital; calculation of marginal costs; and rate design. Mr. McClusky argues that the revenues associated with non-cash items should be excluded from the calculation of CWC. In my rebuttal testimony, I have demonstrated that excluding these non-cash costs from CWC would result in the Company's under-recovery of its allowed rate of return due to the lagged recovery of that portion of total revenue requirements associated with these non-cash costs. In addition, Mr. McClusky has recommended and I have rebutted Staff's recommendation that short term debt should have a 45 day lag.

In addition, I have rebutted several concerns that Mr. McClusky had regarding the Company's marginal cost study. I have demonstrated that Mr. McClusky's recommendation to eliminate CIAC from distribution mains investment does not accurately measure the Company's marginal costs and overstates marginal distribution costs. I have also testified that the use of multi-year data in the distribution reinforcements is a practical and necessary computation that reflects "real world" planning and forecasting. I disagree with Staff's recommendation to ignore the spare meters required to serve the Company's system and have pointed out that such investments are a cost of doing business that reflect the need to keep spare meters in inventory for replacement purposes. Finally, I noted that Mr. McClusky erred in stating that my colleague, James Harrison, excluded uncollectible expenses in Unitil Docket No. DE 05-178 when, in fact, uncollectible expenses were included in that company's marginal costs.

Finally, I addressed Mr. McClusky's pricing recommendations relating to the recovery of fixed, capacity-related costs through the volumetric charge. I noted that other providers of delivery services employed high fixed fees, unrelated to service volume levels, that the Staff's recommendations made the recovery of fixed costs by the Company more risky, introduced even greater variability to the customer bills and produced greater intra-class subsidies among customers.

Q. Please summarize your rebuttal of the testimony of OCA witnesses Smith and Freitas.

A. My rebuttal of the OCA witnesses addressed issues raised by the OCA regarding the marginal cost study and rate design. OCA argued that the Company's marginal cost study should reflect the Company's CIAC proposed policy. I agree and such a study has been provided as part of the discovery process in this case and will be included in the compliance cost study if the NHPUC approves the Company's proposed CIAC tariff changes. I have addressed and rebutted OCA's contention that my use of the 2002 through 2006 period to estimate marginal capacity-related operating and maintenance expense is inappropriate. The period I employed to estimate these costs reflects the use of the best available data which exclude KeySpan merger impacts. I also disagree with and rebut OCA's contention that my use of a non-plant related A&G loading factor is inappropriate. As indicated above, the Company's acquisition affected the accounts to which certain costs were booked, a common occurrence whenever service organizations begin to provide services that were previously undertaken by the operating company. I have employed post-merger data to calculate the non-plant related A&G loading factor since this information best reflects the expected costs faced by the Company. I also rebut OCA's recommendation to reject the use of marginal costs in favor of embedded accounting cost studies on the grounds of economic efficiency and Commission precedent. With regard to OCA's rate design recommendations, I discuss the problems and fallacies with OCA's arguments regarding differences in new investment and the continuing need to provide replacement investment for existing investment.

OCA's rate design recommendations were that the Commission should employ embedded accounting cost studies rather than marginal cost studies as the basis of rate design as described above. I disagree. Marginal costs provide more useful information for pricing purposes. Furthermore, as I explained in my preceding testimony, the Commission has already investigated costing methodologies and has determined that marginal costs provide the most appropriate basis for setting rates.

In my opinion, the CWC requirements proposed for the Company are fair and reasonable, and the methodology I have employed is necessary and proper if the Company is to be allowed a reasonable opportunity to achieve the rate of return authorized by the Commission. I also believe that the marginal cost study I sponsor on behalf of National Grid NH reasonably reflects the marginal costs of providing natural gas delivery service. I have addressed various issues raised by the Staff and OCA regarding specific calculations inherent in the quantification of marginal costs and demonstrated that the methodology I have employed is fair and reasonable and accurately reflects the cost structure of National Grid NH.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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Title 18: Conservation of Power and Water Resources

Browse Next

PART 201—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR NATURAL GAS COMPANIES SUBJECT TO THE PROVISIONS OF THE NATURAL GAS ACT

Section Contents

Authority: 15 U.S.C. 717–717w, 3301–3432; 42 U.S.C. 7101–7352, 7651–7651o.

Source: Order 219, 25 FR 5616, June 21, 1960, unless otherwise noted.

Editorial Note: ForFederal Registercitations affecting part 201, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access.

Effective Date Note: At 58 FR 18006, April 7, 1993, part 201 was amended by redesignating definitions 31 through 39 as 32 through 40 and adding a new definition 31; Accounts 182.3 and 254 were added under Balance Sheet Accounts; and Accounts 407.3 and 407.4 were added under Income Accounts. The added text contains information collection and recordkeeping requirements and will not become effective until approval has been given by the Office of Management and Budget.

Note: Order 141, 12 FR 8504, Dec. 19, 1947, provides in part as follows:

Prescribing a system of accounts for natural gas companies under the Natural Gas Act. The Federal Power Commission acting pursuant to authority granted by the Natural Gas Act (58) Stat. 821, as amended; 15 U.S.C. and Sup. 717 et seq.), particularly sections 8(a), 10(a) and 16 thereof, and finding such action necessary and appropriate for carrying out the provisions of said Act, ordered that:

(a) The accompanying system of accounts, entitled “Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act,” and the rules and regulations contained therein, be adopted;

(b) Said system of accounts and said rules and regulations contained therein be and the same are hereby prescribed and promulgated as the system of accounts and rules and regulations of the Commission to be kept and observed by natural gas companies subject to the jurisdiction of the Commission, to the extent and in the manner set forth therein;

(c) Said system of accounts and rules and regulations therein contained as to all natural gas companies now subject to the jurisdiction of the Commission, became effective on January 1, 1940, and as to any natural gas company which may hereafter become subject to the jurisdiction of the Commission, they shall become effective as of the date when such natural gas company becomes subject to the jurisdiction of the Commission.

874 Mains and services expenses.

This account shall include the cost of labor, materials used and expenses incurred in operating distribution system mains and services.

Items

Labor:

1. Supervising.

2. Walking or patrolling lines.

3. Attending valves, lubricating valves and other equipment, blowing and cleaning lines and drips, draining water from lines, thawing freezes.

4. Taking line pressures, changing pressure charts, operating alarm gauges.

5. Building and repairing gate boxes, foot bridges, stiles, etc. used in distribution mains operations, erecting line markers and warning signs, etc.

6. Cleaning debris, cutting grass and weeds on rights-of-way.

7. Inspecting and testing equipment not specifically to determine necessity for repairs.

8. Protecting utility property during work by others.

9. Standby time of emergency crews, responding to fire calls, etc.

10. Locating and inspecting valve boxes or drip riser boxes, service lines, mains, etc.

11. Cleaning and repairing tools used in mains operations, making tool boxes, etc.

12. Cleaning structures and equipment.

13. Driving trucks used in mains and service operations.

14. Making routine leak survey.

15. Oil fogging.

Materials and Expenses:

1. Line markers and warning signs.

2. Lumber, nails, etc., used in building and repairing gate boxes (foot bridges, stiles, tool boxes, etc.).

3. Charts and printed forms.

4. Scrubber oils.

5. Hand tools.

6. Lubricants, wiping rags, waste, etc.

7. Freight, express, parcel post, trucking and other transportation.

8. Uniforms.

9. Employee transportation and travel expenses.

10. Janitor and washroom supplies.

11. Utility services: light, water, telephone.

12. Gas used in mains operation.

13. Oil for fogging.

875 Measuring and regulating station expenses—General.

This account shall include the cost of labor, materials used and expenses incurred in operating general distribution measuring and regulating stations.

Items

Labor:

1. Supervising.

2. Recording pressures and changing charts, reading meters, etc.

3. Estimating lost meter registrations, etc. except purchases and sales.

4. Calculating gas volumes from meter charts, except gas purchases and sales.

5. Adjusting and calibrating measuring equipment, changing meters, orifice plates, gauges, clocks, etc.

6. Taking and testing gas samples, inspecting and testing valves, regulators, gas sample tanks and other meter engineers' equipment, determining specific gravity and Btu content of gas.

7. Inspecting and testing equipment and instruments not specially to determine necessity for repairs, including pulsation tests.

8. Cleaning and lubricating equipment.

9. Keeping log and other operating records.

10. Attending boilers and operating other accessory equipment.

11. Installing and removing district gauges for pressure survey.

12. Thawing freeze in gauge pipe.

13. Inspecting and pumping drips, dewatering manholes and pits, inspecting sumps, cleaning pits, blowing meter drips, etc.

14. Moving equipment, minor structures, etc., not in connection with maintenance or construction.

Materials and expenses:

15. Charts and printed forms, stationery and office supplies, etc.

16. Lubricants, wiping rags, waste.

17. Uniforms.

18. Employee transportation and travel expenses.

19. Freight, express, parcel post, trucking and other transportation.

20. Utility services: light, water, telephone.

Table 7
UNITIL ENERGY SYSTEMS
MARGINAL COST ANALYSIS (Rev 2.0 - Settlement)

Development of Customer Accounting Expense

Line No.	Year	Customer Accounting Expenses 901-910	Marketing Expenses 911-916	Total Customer Related Expenses	GDP-IPD Cost Index 2004=1.00	Expense in 2004 Dollars (1,000's)	Annual Average Customers	Average Cost per Customer
		(1) {1}{2}	(2)	(3)	(4)	(5)	(6)	(7)
1	1992	$1,750	$0	$1,750	1.25	$2,192	60,488	$36.24
2	1993	1,836	0	1,836	1.22	2,249	61,285	36.69
3	1994	1,950	0	1,950	1.20	2,338	62,517	37.41
4	1995	2,091	0	2,091	1.18	2,457	63,326	38.80
5	1996	2,580	0	2,580	1.15	2,975	62,198	47.83
6	1997	2,844	0	2,844	1.13	3,226	65,427	49.31
7	1998	2,920	0	2,920	1.12	3,276	66,629	49.16
8	1999	2,907	0	2,907	1.11	3,215	67,677	47.50
9	2000	2,431	0	2,431	1.08	2,631	68,760	38.26
10	2001	2,828	0	2,828	1.06	2,989	69,732	42.87
11	2002	2,859	0	2,859	1.04	2,973	71,505	41.58
12	2003	2,386	0	2,386	1.02	2,436	72,378	33.66
13	2004	2,762	0	2,762	1.00	2,762	73,453	37.61
14								
15								
16								

Line No.		
17	REGRESSION RESULTS	
18	Slope =	$32.24
19	Y Intercept =	601348
20	Coefficent of Determination (R^2) =	13.5%
21	T-Statistic =	1.3
22		
23	MARGINAL COST ESTIMATES	
24	Trended Cost - Customers	$32.24
25		
26		
27	Average Cost:	
28	1992-2004	$41.28
29	1999-2004	$40.16
30	2002-2004	$37.60
31		
32		
33		
34	Assumed Marginal Cost {3}	$37.60

NOTES:
1 Cost data taken from annual reports.
2 DSM Expenses have been excluded from account 908 for regression analysis.
3 The statistical relationship is not sufficiently robust to be reliable, consequently the most recent average is employed to estimate marginal costs.

National Grid - NH
Lead-Lag Study
Hypothetical Lead-Lag Base Case

	Rate	Wtg	Cost
Debt	8.0%	50.0%	4.0%
Equity	12.0%	50.0%	6.0%
Total Return=			10.0%
Combined Tax Rate=			40.0%
After Tax Cost of Capital=			14.00%

				YEAR										
			0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
NO LAG														
1	**Investment**			1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00
2	Depreciation	1/10		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
3	Acum Depr				100.00	200.00	300.00	400.00	500.00	600.00	700.00	800.00	900.00	1,000.00
4	CWC Addition			-	-	-	-	-	-	-	-	-	-	-
5	Rate Base	1-3+4		1,000.00	900.00	800.00	700.00	600.00	500.00	400.00	300.00	200.00	100.00	-
6														
7	**Allowed Income**													
8	O&M Expenses			-	-	-	-	-	-	-	-	-	-	
9	Depreciation	2		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
10	Return &Tax	5*ATCOC		140.00	126.00	112.00	98.00	84.00	70.00	56.00	42.00	28.00	14.00	-
11	Billed Revenue	8+9+10		240.00	226.00	212.00	198.00	184.00	170.00	156.00	142.00	128.00	114.00	-
12														
13	**Expenses**													
14	O&M Expenses	8		-	-	-	-	-	-	-	-	-	-	-
15	Depreciation	2		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	-
16	Income Taxes	26		40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
17	Total Expenses	14+15+16		140.00	136.00	132.00	128.00	124.00	120.00	116.00	112.00	108.00	104.00	-
18	Total Return	11-17		100.00	90.00	80.00	70.00	60.00	50.00	40.00	30.00	20.00	10.00	-
19	ROR on Rate Base	18/5		10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	
20														
21	**Tax Calculation**													
22	Revenue	11		240.00	226.00	212.00	198.00	184.00	170.00	156.00	142.00	128.00	114.00	-
23	Depreciation	2		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	-
24	Interest Expense	5XDebt Cost		40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
25	EBIT	22-23-24		100.00	90.00	80.00	70.00	60.00	50.00	40.00	30.00	20.00	10.00	-
26	Income Taxes	25X Tax Rate		40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
27	Return on Equity	25-26		60.00	54.00	48.00	42.00	36.00	30.00	24.00	18.00	12.00	6.00	-
28	ROR on Equity	27/(5XDebt Wt)		12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	
29														
30	**Cash Flow Analysis - Total Return**													
31	Cash Revenues			240.00	226.00	212.00	198.00	184.00	170.00	156.00	142.00	128.00	114.00	-
32	Cash O&M			-	-	-	-	-	-	-	-	-	-	-
33	Cash Depreciation			-	-	-	-	-	-	-	-	-	-	-
34	Cash Income Taxes			40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
35	Cash Bond Interest			-	-	-	-	-	-	-	-	-	-	-
36	Cash Expense		1,000.00	40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
37	Cash Flow		(1,000.00)	200.00	190.00	180.00	170.00	160.00	150.00	140.00	130.00	120.00	110.00	-
38		IRR=	**10.00%**											
39														
40														
41	**Cash Flow Analysis - Return on Common Equity**													
42	Cash Revenues			240.00	226.00	212.00	198.00	184.00	170.00	156.00	142.00	128.00	114.00	-
43	Cash O&M			-	-	-	-	-	-	-	-	-	-	-

National Grid - NH
Lead-Lag Study
Revenue Lag Added to Base Case

	Rate	Wtg	Cost
Debt	8.0%	50.0%	4.0%
Equity	12.0%	50.0%	6.0%
Total Return=			10.0%
Combined Tax Rate=			40.0%
After Tax Cost of Capital=			14.00%

				YEAR										
			0	1	2	3	4	5	6	7	8	9	10	11
1	**Investment**			1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00
2	Depreciation	1/10		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
3	Acum Depr				100.00	200.00	300.00	400.00	500.00	600.00	700.00	800.00	900.00	1,000.00
4	CWC Addition			-	-	-	-	-	-	-	-	-	-	-
5	Rate Base	1-3+4		1,000.00	900.00	800.00	700.00	600.00	500.00	400.00	300.00	200.00	100.00	-
6														
7	**Allowed Income**													
8	O&M Expenses			-	-	-	-	-	-	-	-	-	-	
9	Depreciation	2		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
10	Return &Tax	5*ATCOC		140.00	126.00	112.00	98.00	84.00	70.00	56.00	42.00	28.00	14.00	-
11	Billed Revenue	8+9+10		240.00	226.00	212.00	198.00	184.00	170.00	156.00	142.00	128.00	114.00	-
12														
13	**Expenses**													
14	O&M Expenses	8		-	-	-	-	-	-	-	-	-	-	-
15	Depreciation	2		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	-
16	Income Taxes	26		40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
17	Total Expenses	14+15+16		140.00	136.00	132.00	128.00	124.00	120.00	116.00	112.00	108.00	104.00	-
18	Total Return	11-17		100.00	90.00	80.00	70.00	60.00	50.00	40.00	30.00	20.00	10.00	-
19	ROR on Rate Base	18/5		10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	
20														
21	**Tax Calculation**													
22	Revenue	11		240.00	226.00	212.00	198.00	184.00	170.00	156.00	142.00	128.00	114.00	-
23	Depreciation	2		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	-
24	Interest Expense	5XDebt Cost		40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
25	EBIT	22-23-24		100.00	90.00	80.00	70.00	60.00	50.00	40.00	30.00	20.00	10.00	-
26	Income Taxes	25X Tax Rate		40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
27	Return on Equity	25-26		60.00	54.00	48.00	42.00	36.00	30.00	24.00	18.00	12.00	6.00	-
28	ROR on Equity	27/(5XDebt Wt)		12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	
29														
30	**Cash Flow Analysis - Total Return**													
31	Cash Revenues			-	**240.00**	**226.00**	**212.00**	**198.00**	**184.00**	**170.00**	**156.00**	**142.00**	**128.00**	**114.00**
32	Cash O&M			-	-	-	-	-	-	-	-	-	-	-
33	Cash Depreciation			-	-	-	-	-	-	-	-	-	-	-
34	Cash Income Taxes			40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
35	Cash Bond Interest			-	-	-	-	-	-	-	-	-	-	-
36	Cash Expense		1,000.00	40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
37	Cash Flow		(1,000.00)	(40.00)	204.00	194.00	184.00	174.00	164.00	154.00	144.00	134.00	124.00	114.00
38		IRR=	**6.77%**											
39														
40														
41	**Cash Flow Analysis - Return on Common Equity**													
42	Cash Revenues			-	**240.00**	**226.00**	**212.00**	**198.00**	**184.00**	**170.00**	**156.00**	**142.00**	**128.00**	**114.00**
43	Cash O&M			-	-	-	-	-	-	-	-	-	-	-
44	Cash Depreciation			-	-	-	-	-	-	-	-	-	-	-
45	Cash Income Taxes			40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
46	Cash Bond Interest			40.00	36.00	32.00	28.00	24.00	20.00	16.00	12.00	8.00	4.00	-
47	Cash Expense		1,000.00	80.00	72.00	64.00	56.00	48.00	40.00	32.00	24.00	16.00	8.00	-
48	Change in Debt		(500.00)	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	-
49	Cash Flow		(500.00)	(130.00)	118.00	112.00	106.00	100.00	94.00	88.00	82.00	76.00	70.00	114.00
50		IRR=	**5.84%**											
51														
52	**Lead Lag Studies - Rate Base Adjustment**													
53			Lag, Yrs	$'s										
54	Revenue Lag		1	240.00	226.00	212.00	198.00	184.00	170.00	156.00	142.00	128.00	114.00	-
55														
56	Expense Lag													
57	O&M Expenses		0	-	-	-	-	-	-	-	-	-	-	-
58	Depreciation		0	-	-	-	-	-	-	-	-	-	-	-
59	Taxes		0	-	-	-	-	-	-	-	-	-	-	-
60	Bond Interest		0	-	-	-	-	-	-	-	-	-	-	-
61	Return on Common		0	-	-	-	-	-	-	-	-	-	-	-
62	Expense Lag			-	-	-	-	-	-	-	-	-	-	-
63														
64	Cash Working Capital			240.00	226.00	212.00	198.00	184.00	170.00	156.00	142.00	128.00	114.00	-

National Grid - NH

Lead-Lag Study

Simple CWC Addition to Rate Base

	Rate	Wtg	Cost
Debt	8.0%	50.0%	4.0%
Equity	12.0%	50.0%	6.0%
Total Return=			10.0%
Combined Tax Rate=			40.0%
After Tax Cost of Capital=			14.00%

			-1	0	YEAR 1	2	3	4	5	6	7	8	9	10	11
1	**Investment**				1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00
2	Depreciation	1/10			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
3	Acum Depr					100.00	200.00	300.00	400.00	500.00	600.00	700.00	800.00	900.00	1,000.00
4	CWC Addition				**240.00**	**226.00**	**212.00**	**198.00**	**184.00**	**170.00**	**156.00**	**142.00**	**128.00**	**114.00**	-
5	Rate Base	1-3+4			1,240.00	1,126.00	1,012.00	898.00	784.00	670.00	556.00	442.00	328.00	214.00	-
6															
7	**Allowed Income**														
8	O&M Expenses				-	-	-	-	-	-	-	-	-	-	
9	Depreciation	2			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
10	Return &Tax	5*ATCOC			173.60	157.64	141.68	125.72	109.76	93.80	77.84	61.88	45.92	29.96	-
11	Billed Revenue	8+9+10			273.60	257.64	241.68	225.72	209.76	193.80	177.84	161.88	145.92	129.96	-
12															
13	**Expenses**														
14	O&M Expenses	8			-	-	-	-	-	-	-	-	-	-	-
15	Depreciation	2			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	-
16	Income Taxes	26			49.60	45.04	40.48	35.92	31.36	26.80	22.24	17.68	13.12	8.56	-
17	Total Expenses	14+15+16			149.60	145.04	140.48	135.92	131.36	126.80	122.24	117.68	113.12	108.56	-
18	Total Return	11-17			124.00	112.60	101.20	89.80	78.40	67.00	55.60	44.20	32.80	21.40	-
19	ROR on Rate Base	18/5			10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	
20															
21	**Tax Calculation**														
22	Revenue	11			273.60	257.64	241.68	225.72	209.76	193.80	177.84	161.88	145.92	129.96	-
23	Depreciation	2			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	-
24	Interest Expense	5XDebt Cost			49.60	45.04	40.48	35.92	31.36	26.80	22.24	17.68	13.12	8.56	-
25	EBIT	22-23-24			124.00	112.60	101.20	89.80	78.40	67.00	55.60	44.20	32.80	21.40	-
26	Income Taxes	25X Tax Rate			49.60	45.04	40.48	35.92	31.36	26.80	22.24	17.68	13.12	8.56	-
27	Return on Equity	25-26			74.40	67.56	60.72	53.88	47.04	40.20	33.36	26.52	19.68	12.84	-
28	ROR on Equity	27/(5XDebt Wt)			12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	
29															
30	**Cash Flow Analysis - Total Return**														
31	Cash Revenues				-	273.60	257.64	241.68	225.72	209.76	193.80	177.84	161.88	145.92	129.96
32	Cash O&M				-	-	-	-	-	-	-	-	-	-	-
33	Cash Depreciation				-	-	-	-	-	-	-	-	-	-	-
34	Cash Income Taxes				49.60	45.04	40.48	35.92	31.36	26.80	22.24	17.68	13.12	8.56	-
35	Cash Bond Interest				-	-	-	-	-	-	-	-	-	-	-
36	Cash Expense			1,000.00	49.60	45.04	40.48	35.92	31.36	26.80	22.24	17.68	13.12	8.56	-
37	Cash Flow			(1,000.00)	(49.60)	228.56	217.16	205.76	194.36	182.96	171.56	160.16	148.76	137.36	129.96
38		IRR=		8.93%											
39															
40															
41	**Cash Flow Analysis - Return on Common Equity**														
42	Cash Revenues				-	273.60	257.64	241.68	225.72	209.76	193.80	177.84	161.88	145.92	129.96
43	Cash O&M				-	-	-	-	-	-	-	-	-	-	-
44	Cash Depreciation				-	-	-	-	-	-	-	-	-	-	-
45	Cash Income Taxes				49.60	45.04	40.48	35.92	31.36	26.80	22.24	17.68	13.12	8.56	-
46	Cash Bond Interest				49.60	45.04	40.48	35.92	31.36	26.80	22.24	17.68	13.12	8.56	-
47	Cash Expense			1,000.00	99.20	90.08	80.96	71.84	62.72	53.60	44.48	35.36	26.24	17.12	-
48	Change in Debt			(620.00)	57.00	57.00	57.00	57.00	57.00	57.00	57.00	57.00	57.00	107.00	-
49	Cash Flow			(380.00)	(156.20)	126.52	119.68	112.84	106.00	99.16	92.32	85.48	78.64	21.80	129.96
50		IRR=		10.02%											
51															
52	**Lead Lag Studies - Rate Base Adjustment**														
53				Lag, Yrs	$'s										
54	Revenue Lag			1	240.00	226.00	212.00	198.00	184.00	170.00	156.00	142.00	128.00	114.00	-
55															
56	Expense Lag														
57	O&M Expenses			0	-	-	-	-	-	-	-	-	-	-	-
58	Depreciation			0	-	-	-	-	-	-	-	-	-	-	-
59	Taxes			0	-	-	-	-	-	-	-	-	-	-	-
60	Bond Interest			0	-	-	-	-	-	-	-	-	-	-	-
61	Return on Common			0	-	-	-	-	-	-	-	-	-	-	-
62	Expense Lag				-	-	-	-	-	-	-	-	-	-	-
63															
64	Cash working Capital				240.00	226.00	212.00	198.00	184.00	170.00	156.00	142.00	128.00	114.00	-

National Grid - NH
Lead-Lag Study
Improved CWC Calculation

	Rate	Wtg	Cost
Debt	8.0%	50.0%	4.0%
Equity	12.0%	50.0%	6.0%
Total Return=			10.0%
Combined Tax Rate=			40.0%
After Tax Cost of Capital=			14.00%

					YEAR										
			-1	0	1	2	3	4	5	6	7	8	9	10	11
1	**Investment**				1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00
2	Depreciation	1/10			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
3	Acum Depr					100.00	200.00	300.00	400.00	500.00	600.00	700.00	800.00	900.00	1,000.00
4	CWC Addition				279.07	262.79	246.51	230.23	213.95	197.67	181.40	165.12	148.84	132.56	-
5	Rate Base	1-3+4			1,279.07	1,162.79	1,046.51	930.23	813.95	697.67	581.40	465.12	348.84	232.56	-
6															
7	**Allowed Income**														
8	O&M Expenses				-	-	-	-	-	-	-	-	-	-	
9	Depreciation	2			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
10	Return &Tax	5*ATCOC			179.07	162.79	146.51	130.23	113.95	97.67	81.40	65.12	48.84	32.56	-
11	Billed Revenue	8+9+10			279.07	262.79	246.51	230.23	213.95	197.67	181.40	165.12	148.84	132.56	-
12															
13	**Expenses**														
14	O&M Expenses	8			-	-	-	-	-	-	-	-	-	-	-
15	Depreciation	2			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	-
16	Income Taxes	26			51.16	46.51	41.86	37.21	32.56	27.91	23.26	18.60	13.95	9.30	-
17	Total Expenses	14+15+16			151.16	146.51	141.86	137.21	132.56	127.91	123.26	118.60	113.95	109.30	-
18	Total Return	11-17			127.91	116.28	104.65	93.02	81.40	69.77	58.14	46.51	34.88	23.26	-
19	ROR on Rate Base	18/5			10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	
20															
21	**Tax Calculation**														
22	Revenue	11			279.07	262.79	246.51	230.23	213.95	197.67	181.40	165.12	148.84	132.56	-
23	Depreciation	2			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	-
24	Interest Expense	5XDebt Cost			51.16	46.51	41.86	37.21	32.56	27.91	23.26	18.60	13.95	9.30	-
25	EBIT	22-23-24			127.91	116.28	104.65	93.02	81.40	69.77	58.14	46.51	34.88	23.26	-
26	Income Taxes	25X Tax Rate			51.16	46.51	41.86	37.21	32.56	27.91	23.26	18.60	13.95	9.30	-
27	Return on Equity	25-26			76.74	69.77	62.79	55.81	48.84	41.86	34.88	27.91	20.93	13.95	-
28	ROR on Equity	27/(5XDebt Wt)			12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	
29															
30	**Cash Flow Analysis - Total Return**														
31	Cash Revenues				-	279.07	262.79	246.51	230.23	213.95	197.67	181.40	165.12	148.84	132.56
32	Cash O&M				-	-	-	-	-	-	-	-	-	-	-
33	Cash Depreciation				-	-	-	-	-	-	-	-	-	-	-
34	Cash Income Taxes				51.16	46.51	41.86	37.21	32.56	27.91	23.26	18.60	13.95	9.30	-
35	Cash Bond Interest				-	-	-	-	-	-	-	-	-	-	-
36	Cash Expense			1,000.00	51.16	46.51	41.86	37.21	32.56	27.91	23.26	18.60	13.95	9.30	-
37	Cash Flow			(1,000.00)	(51.16)	232.56	220.93	209.30	197.67	186.05	174.42	162.79	151.16	139.53	132.56
38			IRR=	9.26%											
39															
40															
41	**Cash Flow Analysis - Return on Common Equity**														
42	Cash Revenues				-	279.07	262.79	246.51	230.23	213.95	197.67	181.40	165.12	148.84	132.56
43	Cash O&M				-	-	-	-	-	-	-	-	-	-	-
44	Cash Depreciation				-	-	-	-	-	-	-	-	-	-	-
45	Cash Income Taxes				51.16	46.51	41.86	37.21	32.56	27.91	23.26	18.60	13.95	9.30	-
46	Cash Bond Interest				51.16	46.51	41.86	37.21	32.56	27.91	23.26	18.60	13.95	9.30	-
47	Cash Expense			1,000.00	102.33	93.02	83.72	74.42	65.12	55.81	46.51	37.21	27.91	18.60	-
48	Change in Debt			(639.53)	58.14	58.14	58.14	58.14	58.14	58.14	58.14	58.14	58.14	116.28	-
49	Cash Flow			(360.47)	(160.47)	127.91	120.93	113.95	106.98	100.00	93.02	86.05	79.07	13.95	132.56
50			IRR=	10.86%											
51															
52	**Lead Lag Studies - Rate Base Adjustment**														
53				Lag, Yrs	$'s										
54	Revenue Lag			1	279.07	262.79	246.51	230.23	213.95	197.67	181.40	165.12	148.84	132.56	-
55															
56	Expense Lag														
57	O&M Expenses			0	-	-	-	-	-	-	-	-	-	-	-
58	Depreciation			0	-	-	-	-	-	-	-	-	-	-	-
59	Taxes			0	-	-	-	-	-	-	-	-	-	-	-
60	Bond Interest			0	-	-	-	-	-	-	-	-	-	-	-
61	Return on Common			0	-	-	-	-	-	-	-	-	-	-	-
62	Expense Lag				-	-	-	-	-	-	-	-	-	-	-
63															
64	Cash working Capital				279.07	262.79	246.51	230.23	213.95	197.67	181.40	165.12	148.84	132.56	-

National Grid - NH
Lead-Lag Study
CWC Reduced to Exclude Return

	Rate	Wtg	Cost
Debt	8.0%	50.0%	4.0%
Equity	12.0%	50.0%	6.0%
Total Return=			10.0%
Combined Tax Rate=			40.0%
After Tax Cost of Capital=			14.00%

			-1	0	YEAR 1	2	3	4	5	6	7	8	9	10	11
1	**Investment**				1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00
2	Depreciation	1/10			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
3	Acum Depr					100.00	200.00	300.00	400.00	500.00	600.00	700.00	800.00	900.00	1,000.00
4	CWC Addition				195.65	186.96	178.26	169.57	160.87	152.17	143.48	134.78	126.09	117.39	-
5	Rate Base	1-3+4			1,195.65	1,086.96	978.26	869.57	760.87	652.17	543.48	434.78	326.09	217.39	-
6															
7	**Allowed Income**														
8	O&M Expenses				-	-	-	-	-	-	-	-	-	-	
9	Depreciation	2			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
10	Return &Tax	5*ATCOC			167.39	152.17	136.96	121.74	106.52	91.30	76.09	60.87	45.65	30.43	-
11	Billed Revenue	8+9+10			267.39	252.17	236.96	221.74	206.52	191.30	176.09	160.87	145.65	130.43	-
12															
13	**Expenses**														
14	O&M Expenses	8			-	-	-	-	-	-	-	-	-	-	-
15	Depreciation	2			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	-
16	Income Taxes	26			47.83	43.48	39.13	34.78	30.43	26.09	21.74	17.39	13.04	8.70	-
17	Total Expenses	14+15+16			147.83	143.48	139.13	134.78	130.43	126.09	121.74	117.39	113.04	108.70	-
18	Total Return	11-17			119.57	108.70	97.83	86.96	76.09	65.22	54.35	43.48	32.61	21.74	-
19	ROR on Rate Base	18/5			10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	
20															
21	**Tax Calculation**														
22	Revenue	11			267.39	252.17	236.96	221.74	206.52	191.30	176.09	160.87	145.65	130.43	-
23	Depreciation	2			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	-
24	Interest Expense	5XDebt Cost			47.83	43.48	39.13	34.78	30.43	26.09	21.74	17.39	13.04	8.70	-
25	EBIT	22-23-24			119.57	108.70	97.83	86.96	76.09	65.22	54.35	43.48	32.61	21.74	-
26	Income Taxes	25X Tax Rate			47.83	43.48	39.13	34.78	30.43	26.09	21.74	17.39	13.04	8.70	-
27	Return on Equity	25-26			71.74	65.22	58.70	52.17	45.65	39.13	32.61	26.09	19.57	13.04	-
28	ROR on Equity	27/(5XDebt Wt)			12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	
29															
30	**Cash Flow Analysis - Total Return**														
31	Cash Revenues				-	267.39	252.17	236.96	221.74	206.52	191.30	176.09	160.87	145.65	130.43
32	Cash O&M				-	-	-	-	-	-	-	-	-	-	-
33	Cash Depreciation				-	-	-	-	-	-	-	-	-	-	-
34	Cash Income Taxes				47.83	43.48	39.13	34.78	30.43	26.09	21.74	17.39	13.04	8.70	-
35	Cash Bond Interest					-	-	-	-	-	-	-	-	-	-
36	Cash Expense			1,000.00	47.83	43.48	39.13	34.78	30.43	26.09	21.74	17.39	13.04	8.70	-
37	Cash Flow			(1,000.00)	(47.83)	223.91	213.04	202.17	191.30	180.43	169.57	158.70	147.83	136.96	130.43
38		IRR=		8.63%											
39															
40															
41	**Cash Flow Analysis - Return on Common Equity**														
42	Cash Revenues				-	267.39	252.17	236.96	221.74	206.52	191.30	176.09	160.87	145.65	130.43
43	Cash O&M				-	-	-	-	-	-	-	-	-	-	-
44	Cash Depreciation				-	-	-	-	-	-	-	-	-	-	-
45	Cash Income Taxes				47.83	43.48	39.13	34.78	30.43	26.09	21.74	17.39	13.04	8.70	-
46	Cash Bond Interest				47.83	43.48	39.13	34.78	30.43	26.09	21.74	17.39	13.04	8.70	-
47	Cash Expense			1,000.00	95.65	86.96	78.26	69.57	60.87	52.17	43.48	34.78	26.09	17.39	-
48	Change in Debt			(597.83)	54.35	54.35	54.35	54.35	54.35	54.35	54.35	54.35	54.35	108.70	-
49	Cash Flow			(402.17)	(150.00)	126.09	119.57	113.04	106.52	100.00	93.48	86.96	80.43	19.57	130.43
50		IRR=		9.34%											
51															
52	**Lead Lag Studies - Rate Base Adjustment**														
53				Lag, Yrs	$'s										
54	Revenue Lag			1	195.65	186.96	178.26	169.57	160.87	152.17	143.48	134.78	126.09	117.39	-
55															
56	Expense Lag														
57	O&M Expenses			0	-	-	-	-	-	-	-	-	-	-	-
58	Depreciation			0	-	-	-	-	-	-	-	-	-	-	-
59	Taxes			0	-	-	-	-	-	-	-	-	-	-	-
60	Bond Interest			0	-	-	-	-	-	-	-	-	-	-	-
61	Return on Common			0	-	-	-	-	-	-	-	-	-	-	-
62	Expense Lag				-	-	-	-	-	-	-	-	-	-	-
63															
64	Cash working Capital				195.65	186.96	178.26	169.57	160.87	152.17	143.48	134.78	126.09	117.39	-