THE STATE OF NEW HAMPSHIRE

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April 16, 2007

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Debra Howland
Executive Secretary and Director
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, New Hampshire 03301

Re: DG 07-033 Northern Utilities, Inc.
2007 Summer Cost of Gas

Dear Ms. Howland:

Enclosed for filing with the Commission on behalf of Commission Staff is the testimony of George R. McCluskey in the above captioned docket.

Thank you for your attention to this matter.

Sincerely yours,

F. Anne Ross
Staff Attorney

Cc: Service List

STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

DG 07-033

In the Matter of:
Northern Utilities, Inc.
Summer 2007 Cost of Gas

Direct Testimony

of

George R. McCluskey
Utility Analyst

April 16, 2007

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is George McCluskey, and my business address is the New Hampshire Public Utilities Commission, 21 South Fruit Street, Suite 10, Concord, NH 03301.

Q. WHAT IS YOUR POSITION WITH THE NHPUC?

A. I am a Utility Analyst within the Electricity Division of the NHPUC. I also assist the staff of the Gas & Water Division on gas-related policy issues.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION ON GAS-RELATED ISSUES?

A. Yes, on several occasions.

Q. PLEASE DESCRIBE YOUR EDUCATION AND YOUR BUSINESS EXPERIENCE.

A. I am a utility ratemaking specialist with over 20 years experience in utility economics. I rejoined the NHPUC in March 2005 after working as a consultant for La Capra Associates, a Boston-based consulting firm that specializes in electric industry restructuring, wholesale and retail power procurement, and market price and risk analysis. Prior to joining La Capra Associates, I directed the electric utility restructuring division of the Commission and before that was manager of least cost planning, directing and supervising the review and implementation of electric utility least cost plans and demand-side management programs. I have participated in electric and gas restructuring-related activities in New Hampshire, Arkansas, Pennsylvania, California and Ohio. A copy of my resume is included as Exhibit GRM-1.

Q. WHAT IS THE BACKGROUND TO YOUR TESTIMONY IN THIS PROCEEDING?

A. In the 2006-07 Winter Cost of Gas ("COG") proceeding for Northern Utilities Inc. ("Northern" or "Company"), Docket DG 06-129, Staff and the OCA expressed the concern that the method used by Northern to account for revenues in its COG reconciliation calculation may be the source of significant monthly cost and revenue imbalances. Staff and the OCA also expressed the concern that if Northern is allowed to recover through the COG rate the cost to finance these imbalances customers could end up paying twice; once through a rate adjustment to collect the under/over collection from the COG reconciliation and a second time through a rate adjustment to collect the cost to finance Northern's supply-related working capital. Supply-related working capital is the amount of cash needed to support the delay in the receipt of gas revenues relative to the payment of gas costs. In Order No. 24,684, the Commission directed Staff and the parties to: (i) hold discussions to determine whether the concerns are valid and, if so, how they might be resolved; and (ii) file a report on the results of the discussions prior to Northern filing its 2007 Summer COG rate.

Q. DID STAFF AND THE PARTIES COMPLY WITH THE COMMISSION'S INSTRUCTIONS?

A. Yes, discussions were held and a report titled <u>Report on Northern's Calculation of Carrying Charges Related to the Development of the Cost of Gas Rate</u> was filed on March 15, 2007. However, because Northern was not persuaded that the costs of timing differences have been over-collected, the report was submitted on behalf of Staff and the OCA only.

Q. HOW DOES THE REPORT RESOLVE THE OVER-COLLECTION ISSUE?

A. It recommends that Northern modify the COG reconciliation calculation by replacing billed revenues with accrued revenues derived from the gas utilized by customers each calendar month.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My primary purpose is to summarize the report and explain how its recommendations resolve the over-collection problem. A copy of the report is included as Exhibit GRM-2.

Q. WHAT IS THE RELATIONSHIP, IF ANY, BETWEEN THE REPORT'S CONTENTS AND NORTHERN'S SUMMER COG?

A. Although the report focuses on COG reconciliation for the 2005-06 winter period, the arguments and recommendations made therein apply with equal force to summer COG reconciliations. For this reason, Staff requests that the Commission review the report's conclusions and recommendations in this proceeding.

Q. DOES YOUR TESTIMONY ADDRESS OTHER ISSUES?

A. Yes, it does. In addition to the projected gas cost for the 2007 summer period, the proposed COG rate recovers several other costs including the cost to finance the supply-related working capital for summer 2007. This cost was calculated by multiplying the working capital requirement by the overall cost of capital approved in Northern's last base rate proceeding (Order No. 24,075 in Docket DG 01-182). My testimony questions whether Northern's overall cost of capital is an appropriate carrying charge rate for this purpose.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Following this introduction, I summarize in Section II the discussions among Staff and the parties regarding the concerns expressed in Docket DG 06-129. This is followed in Section III with a summary of the arguments and recommendations contained in the report. Section IV addresses the appropriate level of the carrying charge rate for calculating financing costs associated with supply-related working capital.

II. DISCUSSION OF ISSUES RAISED IN DOCKET DG 06-129

Q. PLEASE SUMMARIZE THE DISCUSSIONS BETWEEN STAFF AND THE PARTIES REGARDING THE CONCERNS EXPRESSED IN DOCKET DG 06-129.

A. Staff met with Northern and OCA representatives on two separate occasions. At the first meeting in early December 2006, Northern presented a monthly cash flow analysis that allegedly calculated the Company's "true" supply-related working capital requirement. Northern argued that because the cash flow analysis shows that the "true" supply-related working capital requirement equals the sum of the individual working capital requirements from the two rate adjustments (reconciliation and cash working capital); the rate adjustments must be valid.

At the second meeting in March 2007, Staff presented its assessment of Northern's December cash flow analysis. In short, Staff argued that the "true" supply-related working capital was, in fact, overstated in Northern's analysis due to the inadvertent inclusion of an extra 15-day revenue lag. At the same meeting, Northern withdrew its cash flow analysis but replaced it with a new analysis. That analysis calculated the impact on financing charges of retaining billed revenues in the COG reconciliation but adding revenue associated with gas utilized in October but billed in November to the first month of the winter reconciliation calculation.[1] To be consistent, Northern also added revenue associated with gas utilized in April but billed in May to the first month of the summer reconciliation calculation.[2] Northern's hybrid method increased financing charges (relative to using accrued revenues) by $87,230 for the 2005-06 winter period and reduced financing charges (relative to using accrued revenues) by $76,644 for the summer period, for a net increase of $10,586. However, compared to the existing billed revenue approach, the annual financing charges using Northern's new analysis would fall substantially.

Q. DID STAFF INTERPRET THE NEW ANALYSIS AS AN OFFER BY NORTHERN TO ADDRESS STAFF'S CONCERNS?

A. Because there was some confusion at the meeting regarding the reason for Northern's new analysis, Staff asked Northern to submit a proposal that addressed the concerns raised by Staff and the OCA. Northern subsequently informed Staff

[1] A corresponding reduction to October revenue in the summer reconciliation calculation must be made.
[2] A corresponding reduction to April revenue in the winter reconciliation calculation would have to be made.

that it would not be submitting a proposal and that it believed Staff had the burden of showing that Northern's current approach was unreasonable.

Q. DID THE COMPANY EXPLAIN WHY IT WOULD NOT SUPPORT THE USE OF ACCRUED REVENUES IN THE COG RECONCILATION?

A. No.

Q. DO YOU HAVE ANY COMMENTS ON NORTHERN'S NEW ANALYSIS?

A. Yes. While the new analysis results in a substantial reduction in financing charges relative to the existing approach, it does so by assigning summer revenues to the winter and winter revenues to the summer. This is clearly contrary to standard ratemaking practice and, as a result, places the new analysis squarely in the category of hybrid approaches. More importantly, given the small difference in financing charges between using accrued revenues and the new analysis, I am puzzled by the Company's opposition to Staff's recommendation and to Northern's inability to provide an explanation for that opposition. This opposition is made even more puzzling by the recent adoption, discussed in the next section, of accrual accounting by New Hampshire's three electric utilities.

III. <u>REPORT ON THE COLLECTION OF COSTS TO FINANCE TIMING DIFFERENCES</u>

Q. PLEASE SUMMARIZE THE REPORT'S CONCLUSIONS.

A. As explained in the report, Northern is currently authorized to collect through the COG rate the cost to finance supply-related working capital. Supply-related working capital is the cash needed to support the delay in the receipt of the gas supply portion of revenues relative to the payment of gas supply costs. The amount to be collected is a function of this delay, or timing difference, which is determined with the aid of a lead/lag study.[3] Based on an average net lag of 6.33 days per month determined in Docket DG 01-182, the Company requested collection of $80,551 in the 2006-07 winter COG proceeding and $17,687 in the current proceeding, or an annual working capital cost of $98,238.

If the DG 01-182 lead/lag study was conducted properly and took into account all of the factors that determine when customer payments are received and when supplier costs are paid, including the effect on customer receipts of Northern's billing cycle, the above working capital rate adjustments would fully compensate Northern for the costs of timing differences over the twelve month period November 2006 through October 2007. Stated differently, a second rate adjustment to recover the cost of timing differences (such as the reconciliation rate adjustment) would be unnecessary. Staff's report, however, shows in unmistakable terms that timing differences contribute to the monthly imbalances in Northern's COG reconciliation calculation and, hence, to the reconciliation rate adjustment. In short, if Northern's lead/lag study was conducted correctly, the report provides evidence that the costs of timing differences are over-collected.

Q. CAN THE AMOUNT OF THE OVER-COLLECTION BE ESTIMATED?

A. Yes. For the reasons explained in the report, the over-collection is attributable to Northern's failure to properly match costs and revenues in the COG reconciliation. Fortunately, this mismatch can easily be undone by replacing the

[3] A lead/lag study is a systematic procedure for determining the average number of days investors supply working capital to operate the utility.

monthly billed revenues in the COG reconciliation with monthly accrued revenue estimates. Using accrued revenues developed by Northern, the over-collection for the 2005-06 winter period is estimated at approximately $167,000.[4]

Q. THE COMPANY INTIMATED DURING THE DISCUSSIONS THAT THE LEAD/LAG STUDY DEVELOPED IN DG 01-182 DOES NOT CAPTURE ALL OF THE FACTORS THAT AFFECT WHEN CUSTOMERS PAY THEIR BILLS. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S ARGUMENT?

A. It was suggested that because daily gas usage is much more variable during the winter months than daily power usage, the standard method for calculating revenue lags might not capture the total lag experienced by gas utilities. Specifically, it was suggested that because the weather becomes increasingly colder as the winter progresses, daily gas usage and hence daily revenue will be higher at the end of, say, November than at the beginning. The Company's contention, as I understand it, is twofold. First, the Company contends that the increase in daily revenue results in a longer lag. Second, this longer lag is not captured in the existing study.

Q. DO YOU HAVE ANY COMMENTS ON THIS ARGUMENT?

A. I have two initial comments. First, Northern has not yet explained, either verbally or in writing, how an increase in daily revenue translates into a longer revenue lag. Second, Northern has not addressed the fact that daily revenue typically falls in the late winter and spring months, a fact which (using the same logic) would

[4] Calculated by subtracting the total interest charge in Attachment 1 of the report from the total interest charge in Attachment 2. This estimate, however, should be treated with caution given that the accrued revenue estimate for February 2006 appears unreasonably low by the standards of January and March 2006.

tend to shorten the revenue lag. Until these issues are addressed, I am unable to comment further.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED THIS ISSUE?

A. Yes. The potential over-collection of timing difference costs was first raised in Docket DE 06-123, a Unitil Energy Systems ("UES") default service proceeding. In that proceeding, Staff and the parties initially agreed to remove from the calculation of the default service rate all of the financing costs associated with the COG reconciliation pending further investigation of the over-collection issue.[5] Subsequently, UES agreed to replace billed revenues with accrued revenues in its default service reconciliation calculations.[6] In a separate default service proceeding, Docket DE 07-012, National Grid agreed to modify its default service reconciliation calculation by replacing billed revenues with accrued revenues.

Q. ARE YOU AWARE OF OTHER RECONCILATION MECHANISMS THAT EMPLOY ACCRUAL ACCOUNTING?

A. Yes. In Docket DE 06-028, the Commission approved a settlement agreement that allowed Public Service Company of New Hampshire to establish for the first time a mechanism to reconcile its transmission-related costs and revenues. The settlement agreement requires transmission costs and revenues to be based on accrual accounting. In Docket DE 07-035, UES has proposed to employ accrual accounting in the reconciliation of stranded costs, external delivery costs, and the transition service charge credit.

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[5] See Order No. 24-682.

[6] See Order Nos. 24-735 and 24-736 respectively.

IV. CARRYING CHARGE RATE

Q. AS NOTED ABOVE, NORTHERN IS AUTHORIZED TO COLLECT THROUGH ITS COG RATE THE COST TO FINANCE ITS SUPPLY-RELATED WORKING CAPITAL. NORTHERN CALCULATES THIS COST BY MULTIPLYING ITS WORKING CAPITAL REQUIREMENT BY A CARRYING CHARGE RATE. DO YOU AGREE WITH NORTHERN'S SELECTION OF THE CARRYING CHARGE RATE?

A. No. Northern used the weighed cost of capital grossed up for income taxes approved in its last distribution rate case. As such, it includes an equity component that reflects all of the risks experienced by gas distribution companies including business risk, regulatory risk, financial risk and liquidity risk. The risks of recovering direct gas costs, however, are significantly lower than the risks of recovering distribution costs. Indeed, absent imprudence in entering into gas supply contracts, there is virtually no risk that Northern will under-recover direct gas costs. Accordingly, it would be inappropriate to award Northern a return on its supply-related working capital that reflects the risks of the more risky distribution service.

Q. WHY ARE THE RISKS OF RECOVERING DIRECT GAS COSTS SIGNIFICANTLY LOWER THAN THE RISKS OF RECOVERING DISTRIBUTION COSTS?

A. Gas supply costs are subject to a reconciliation mechanism that guarantees full recovery of all prudently incurred costs including the cost to finance temporary delays in the collection of gas costs relative to the payment of gas expenses.

Because of this mechanism, as natural gas prices rise, as they have in recent years, Northern is not at risk for the higher gas costs. With regard to its distribution costs, however, Northern is at risk of higher labor costs, higher health care expenses, the effect of inflation on the cost of distribution plant and equipment, and the effect of load loss on the recovery of fixed costs.

Q. GIVEN THESE ARGUMENTS, WHAT IS AN APPROPRIATE CARRYING CHARGE RATE FOR SUPPLY-RELATED WORKING CAPITAL?

A. Since the recovery of direct gas costs is essentially risk-free and supply-related working capital is a short-term borrowing requirement, an appropriate carrying charge would be Northern's weighted cost of short-term debt.

Q. IS THERE ANOTHER REASON FOR USING THE SHORT-TERM DEBT RATE?

A. Yes. In Order No. 24,095, the Commission approved Northern's request to use the NiSource System Money Pool to finance its fuel inventory. The Money Pool, however, is also used to fund Northern's other short-term borrowing requirements including its receivables (i.e., working capital).[7] Thus, the appropriate carrying charge rate for calculating the cost of supply-related working capital would be the interest rate that Northern pays to borrow from the Pool, which is effectively Northern's short-term debt cost.

[7] See Direct Testimony of Vincent Rea on behalf of Bay State Gas Company before MDTE in Docket 01-75 and MDTE order in DT 01-75 approving Bay State participation in Money Pool. See also NHPUC Order No. 24,095, at page 6.

Q. HAS THE ISSUE OF THE CARRYING CHARGE RATE FOR SUPPLY-RELATED WORKING CAPITAL BEEN ADDRESSED PREVIOUSLY?

A. Yes. In Docket DE 06-123, a UES default service proceeding, the Commission directed UES to use the prime rate to calculate the cost to finance its power supply-related working capital. In Docket DE 07-012, a National Grid default service proceeding, the Commission approved a default service rate that, among other things, recovered supply-related working capital costs calculated using the prime rate.

Q. IS THERE ANY REASON WHY THE ABOVE DECISIONS SHOULD NOT APPLY TO GAS UTILITIES?

A. The first thing to note is that the Commission in both proceedings found that use of a utility's overall cost of capital to calculate financing costs on supply-related working capital is inappropriate. For the reasons set forth above, I concur with those decisions. As regards the use of the prime rate for establishing financing costs, while that would be a substantial improvement compared with use of the overall cost of capital, I believe the short-term debt rate is even better because it reflects Northern's actual short-term borrowing costs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit GRM-1

GEORGE R. McCLUSKEY

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
Utility Analyst

George McCluskey is a ratemaking specialist with over 20 years experience in utility economics. Since rejoining the New Hampshire Public Utilities Commission ("NHPUC.") in 2005, he has worked on default service, standby rate and least cost planning issues in the electric sector and cost allocation and least cost planning issues in the gas sector. While at La Capra Associates, a Boston-based consulting firm specializing in electric industry restructuring, wholesale and retail power procurement, market price and risk analysis, and power systems models and planning methods, he provided strategic advice to numerous clients on a variety of issues. Prior to joining La Capra Associates, Mr. McCluskey directed the electric utility restructuring division of the NHPUC and before that was manager of least cost planning, directing and supervising the review and implementation of electric and gas utility least cost plans and demand-side management programs. He has testified as an expert witness in numerous electric and gas cost-of-service and rate design proceedings before the NHPUC and the FERC.

ACCOMPLISHMENTS

Recent project experience includes:

Staff of the New Hampshire Public Utilities Commission – Expert testimony before the NHPUC regarding default service design and pricing issues in case involving Unitil Energy Systems.

Staff of the Arkansas Public Service Commission – Analysis and case support regarding Entergy Arkansas Inc.'s application to transfer ownership and control of its transmission assets to a Transco. Also analyzed Entergy Arkansas Inc.'s stranded generation cost claims.

Massachusetts Technology Collaborative – Evaluated proposals by renewable resource developers to sell Renewable Energy Credits to MTC in reponse to 2003 RFP.

Pennsylvania Office of the Consumer Advocate – Analysis and case support regarding horizontal and vertical market power related issues in the PECO/Unicom merger proceeding. Also advised on cost-of-service, cost allocation and rate design issues in FERC base rate case for interstate natural gas pipeline company.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before the NHPUC regarding stranded cost issues in Restructuring Settlement Agreement submitted by Public Service Company of New Hampshire and various settling parties. Testimony presents an analysis of PSNH's stranded costs and makes recommendations regarding the recoverability of such costs.

Town of Waterford, CT – Advisory and expert witness services in litigation to determine property tax assessment of for nuclear power plant.

Washington Electric Cooperative, Vt – Prepared report on external obsolescence in rural distribution systems in property tax case.

New Hampshire Public Utilities Commission - Expert testimony on behalf of the NHPUC before the Federal Energy Regulatory Commission regarding the Order 888 calculation of wholesale stranded costs for utilities receiving partial requirements power supply service.

Ohio Consumer Council - Expert testimony regarding the transition cost recovery requests submitted by the AEP companies, including a critique of the DCF and revenues lost approaches to generation asset valuation.

EXPERIENCE

New Hampshire Public Utilities Commission (2005 to Present)
Utility Analyst, Electricity Division

La Capra Associates (1999 to 2005)
Senior Consultant

New Hampshire Public Utilities Commission (1987 – 1999)
Director, Electric Utilities Restructuring Division
Manager, Lease Cost Planning
Utility Analyst, Economics Department

Electricity Council, London, England (1977-1984)
Pricing Specialist, Commercial Department
Information Officer, Secretary's Office

EDUCATION:

Ph.D. candidate in Theoretical Plasma Physics, University of Sussex Space Physics Laboratory.
Withdrew in 1997 to accept position with the Electricity Council.

B.S., University of Sussex, England, 1975.
Theoretical Physics

REPORT ON NORTHERN'S CALCULATION OF CARRYING CHARGES RELATED TO THE DEVELOPMENT OF THE COST OF GAS RATE

Introduction

Each fall, Northern Utilities Inc. (Northern or Company) files with the Commission an estimated Cost of Gas (COG) rate for the upcoming six month winter period which begins November of the current year and ends April of the following year.[1] In addition to the projected direct gas costs for the winter period, the winter COG rate covers several other costs that relate to gas supply service. These include: (i) prior winter period under/over collection; (ii) demand-related costs incurred during the summer period[2] but deferred for recovery during the winter period; (iii) carrying charges on the deferred costs; (iv) carrying charges on mismatch between monthly direct gas costs and revenues; (v) carrying charges on working capital; (vi) bad debt costs; (vii) depreciation and return on peak shaving plant; (viii) labor costs related to gas dispatch operations; and (ix) interruptible profits. This report focuses on the methods used by Northern to calculate the amounts covered by items (i), (iii), (iv) and (v).

In the COG filing for the winter 2006-07 period, Northern sought to recover: (i) an under-collection of $2,122,758 for the prior winter period including $264,222 in carrying charges; (ii) carrying charges of $142,327 on both the deferred and direct gas costs; and (iii) carrying charges of $76,065 relating to working capital. These amounts compare to

[1] Also known as the peak period.
[2] The summer period, May through October, is also known as the off-peak period.

total direct gas costs of $40,052,618 for the 2006-07 winter period.[3] At the October 18, 2006 hearing, Staff and the OCA expressed the concern that the method used by Northern to account for revenues in its prior period reconciliation calculation may be creating imbalances between monthly gas costs and revenues that must be financed, resulting in additional costs to consumers. Also, Staff and the OCA was concerned that the recovery of these carrying costs through the winter COG rate could result in the Company being compensated twice for these costs, once through a rate adjustment to collect the prior period under-collection and a second time through a rate adjustment to collect the carrying costs on working capital. In order to address this concern, Staff and the OCA recommended that they work with the Company to determine whether their concerns are valid and, if so, how they might be resolved. In Order No. 24,684, the Commission directed the parties and Staff to file a report on the results of their discussions prior to Northern filing its Summer 2007 COG rate. Because the parties and Staff have been unable to reach agreement on whether the Company is over-collecting its carrying costs, this report presents the views of Staff and the OCA only.

Reconciliation Calculation

As noted above, Northern's reconciliation calculation produced an under-collection of $2,122,758 inclusive of carrying charges totaling $264,222. See Attachment 1. The period covered by this calculation is the twelve months May 2005 through April 2006 instead of the six winter months because the Company defers for recovery during the winter a portion of the demand-related gas costs incurred during the summer. Because of these cost deferrals, imbalances between monthly gas costs and revenues are created

[3] Including summer demand-related deferred costs.

throughout the summer period. It is also important to note that the reconciliation calculation includes a thirteenth month (May 2006) that relates to Northern's practice of using billed as opposed to accrued revenues in its reconciliation calculation.[4] This report contends that the use of billed revenue in the reconciliation calculation for the prior winter period resulted in carrying charges that are more than double the amount that would have been incurred had accrued revenues been used.[5] See Attachment 2.

Attachment 1 shows that despite the fact that the prior winter period beginning balance was a credit of $544,444, the deferral of summer demand charges resulted in an end-of-October under-collection of $2,185,271. In November 2005, however, the under-collection swelled to $5,773,513. This increase is explained, in part, by the use of different accounting treatments for costs and revenues in the reconciliation calculation. November gas costs correspond to the full cost of gas purchased in the month, a practice known as accrual accounting. In contrast, November revenue is not based on the total amount of gas consumed in the month. Rather, that revenue is based only on the amount of gas that the Company calculated would be billed and consumed in November. Revenue associated with gas consumed in November but billed in December is assigned to December.[6] Continuing the comparison into the next month, December gas costs correspond to the cost of gas purchased in that month whereas December revenue

[4] Northern also uses billed revenues to calculate the carrying costs to be collected on a going forward basis through the winter COG rate.
[5] It is interesting to note that the approved COG rate for the 2005-06 winter period included $78,993 in estimated carrying costs. Thus, if the $264,222 request is approved, Northern would have collected a total of $343,215 in carrying costs for the 2005-06 winter period.
[6] Revenue that is assigned based on the month in which it was billed is known as billed revenue.

comprises revenue associated with gas consumed in November but billed in December plus revenue associated with gas billed and consumed in December.

Despite the use of different accounting treatments, it might be argued that billed revenue is a reasonable proxy for accrued revenue and, therefore, unlikely to produce large monthly imbalances and associated large financing charges. There are two facts that suggest this outcome is improbable. The first relates to the Company's implementation of billed revenue accounting. Under the above described billed revenue accounting, revenue associated with gas consumed in October but billed in November would be assigned to November. The Company, however, assigns that revenue to October because October falls outside of the winter period. As a result, November billed revenue should be much less than November gas costs producing a large cost under-collection. In fact, if the number of daily meter reads is constant and daily gas consumption does not change, November billed revenue would only be half November gas costs. This suggests that the use of billed revenue accounting produces on average a delay of half a month, or 15 days, between the time a customer receives service and the time when the customer's meter is read. Northern, however, is compensated through its working capital rate adjustment for the carrying costs associated with this 15 day lag. Accordingly, allowing the recovery of these carrying charges through a second rate adjustment would constitute double recovery.

The second fact relates to the assumption of constant daily gas consumption. Because the weather in November becomes increasingly colder as the month progresses, daily gas consumption does not remain constant but actually increases. This means that the revenue associated with consumption in the second half of the month is greater than the revenue associated with consumption in the first half. It also means that the revenue shifted to December because of the 15 day lag is greater than half the November total. Thus, November billed revenue should be less than half November gas costs. This is confirmed in Attachment 1, which shows November gas costs of $5,142,673 and November revenue of only $1,575,928. While most of this November difference would be eliminated under accrual accounting, it is unclear whether the Company's existing working capital rate adjustment appropriately takes into account the effect on carrying charges of changes in daily gas consumption over the full winter period. If not, Northern should conduct a more detailed lead/lag study and use the results of that study to justify any proposed modifications.

Staff and OCA Recommendations

Based on the above analysis, Staff and the OCA believe that the combination of Northern's working capital and reconciliation rate adjustments over-collects the costs of timing differences. In order to correct this problem, Staff and the OCA recommend that Northern's reconciliation calculation be modified such that monthly revenues reflect accrued revenues derived from the amount utilized by customers each calendar month. Also, Staff and the OCA recommend that the Company conduct an analysis to determine whether its current supply-related working capital calculation appropriately takes into account the effect on carrying charges of variations in daily gas consumption throughout the winter period.

Attachment 1

Northern Utilities, Inc.
Prior Period Reconciliation Calculation
May 2005 - April 2006

Billed Revenues

	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Total
Per Settlement in DG 05-080	$ (544,444)													
Beginning Balance	$ 501,688	$639,135	$ 708,853	$ 1,580,586	$ 1,381,097	$1,705,111	$ 2,185,271	$ 5,773,513	$ 7,425,449	$ 6,832,502	$ 7,059,875	$ 6,296,649	$ 3,910,786	
Gas Costs	$ 681,577	$ 66,636	$ 866,024	$ (206,875)	$ 316,318	$ 469,652	$ 5,142,673	$ 7,985,684	$ 8,304,079	$ 7,506,372	$ 6,407,299	$ 2,413,891	$ 22,782	
Billed Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$(1,575,928)	$(6,369,399)	$ (8,938,491)	$(7,319,399)	$(7,209,368)	$(4,831,553)	$(1,830,680)	$ (38,074,818)
Ending Balance w/o Interest	$ 638,821	$705,771	$ 1,574,877	$ 1,373,711	$ 1,697,415	$2,174,763	$ 5,752,016	$ 7,389,798	$ 6,791,037	$ 7,019,475	$ 6,257,806	$ 3,878,987	$ 2,102,888	
Average Balance	$ 570,254	$672,453	$ 1,141,865	$ 1,477,149	$ 1,539,256	$1,939,937	$ 3,968,644	$ 6,581,656	$ 7,108,243	$ 6,925,988	$ 6,658,841	$ 5,087,818	$ 3,006,837	
Prime Rate	5.50%	5.50%	6.00%	6.00%	6.00%	6.50%	6.50%	6.50%	7.00%	7.00%	7.00%	7.50%	7.93%	
Interest Applied	$ 314	$ 3,082	$ 5,709	$ 7,386	$ 7,696	$ 10,508	$ 21,497	$ 35,651	$ 41,465	$ 40,402	$ 38,843	$ 31,799	$ 19,870	$ 264,222
Ending Balance with Interest	$ 639,135	$708,853	$ 1,580,586	$ 1,381,097	$ 1,705,111	$2,185,271	$ 5,773,513	$ 7,425,449	$ 6,832,502	$ 7,059,875	$ 6,296,649	$ 3,910,786	$ 2,122,759	

Source: Form III, Schedule 2, revised Cost of Gas filing, October 17, 2006.

Attachment 2

Northern Utilities, Inc.
Prior Period Reconciliation Calculation
May 2005 - April 2006

Calendar Month Revenues

	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	Total
Per Settlement in DG 05-080	$ (544,444)												
Beginning Balance	$ 501,688	$ 639,135	$ 708,853	$ 1,580,586	$ 1,381,097	$ 1,705,111	$ 2,185,271	$ 2,499,745	$ 2,221,022	$ (1,454,895)	$ 2,825,338	$ 2,819,467	
Gas Costs	$ 681,577	$ 66,636	$ 866,024	$ (206,875)	$ 316,318	$ 469,652	$ 5,142,673	$ 7,985,684	$ 8,304,079	$ 7,506,372	$ 6,407,299	$ 2,413,891	
Calendar Month Revenues *	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,840,854)	$ (8,277,158)	$ (11,982,224)	$ (3,230,123)	$ (6,429,586)	$ (3,353,747)	$ (38,113,692)
Ending Balance w/o Interest	$ 638,821	$ 705,771	$ 1,574,877	$ 1,373,711	$ 1,697,415	$ 2,174,763	$ 2,487,090	$ 2,208,271	$ (1,457,123)	$ 2,821,354	$ 2,803,051	$ 1,879,611	
Average Balance	$ 570,254	$ 672,453	$ 1,141,865	$ 1,477,149	$ 1,539,256	$ 1,939,937	$ 2,336,181	$ 2,354,008	$ 381,949	$ 683,229	$ 2,814,195	$ 2,349,539	
Prime Rate	5.50%	5.50%	6.00%	6.00%	6.00%	6.50%	6.50%	6.50%	7.00%	7.00%	7.00%	7.50%	
Interest Applied	$ 314	$ 3,082	$ 5,709	$ 7,386	$ 7,696	$ 10,508	$ 12,654	$ 12,751	$ 2,228	$ 3,986	$ 16,416	$ 14,685	$ 97,415
Ending Balance with Interest	$ 639,135	$ 708,853	$ 1,580,586	$ 1,381,097	$ 1,705,111	$ 2,185,271	$ 2,499,745	$ 2,221,022	$ (1,454,895)	$ 2,825,338	$ 2,819,467	$ 1,894,296	

Source of data: Northern Response to Staff 2-7, Page 1 of 4, Docket DG 06-129.