STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
	:	
Proposed general increase in natural gas rates (tariffs filed March 9, 2007)	:	**Docket No. 07-0241**
	:	
	:	**(cons.)**
The Peoples Gas Light and Coke Company	:	
	:	
Proposed general increase in natural gas rates (tariffs filed March 9, 2007)	:	**Docket No. 07-0242**
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INITIAL BRIEF OF THE STAFF OF THE ILLINOIS COMMERCE COMMISSION

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October 12, 2007

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INITIAL BRIEF OF THE

STAFF OF THE ILLINOIS COMMERCE COMMISSION

Staff of the Illinois Commerce Commission ("Staff"), by and through its counsel, pursuant to Section 200.800 of the Rules of Practice (83 Ill. Adm. Code 200.800) of the Illinois Commerce Commission's ("Commission"), respectfully submits its Initial Brief in the above-captioned matter.

I. INTRODUCTION

A. Summary

North Shore Gas Company ("North Shore") and the Peoples Gas Light and Coke Company ("Peoples Gas") (individually, the "Company" and collectively the "Companies") filed new tariff sheets on March 9, 2007 in which the Companies proposed general increase in their natural gas rates. On April 4, 2007 the Companies' tariff sheets were suspended by the Commission and on July 25, 2007 the Commission entered a Re-suspension Order extending the suspension to and including February 5, 2008. In due course, the Administrative Law Judges ("ALJs") assigned to this proceeding established a schedule for the submission of pre-filed testimony, hearings and briefs. (Notice of Administrative Law Judges' Ruling, April 27, 2007)

In response to the Company's filing, the following parties filed Petitions to Intervene, which were granted: Citizens Utility Board ("CUB"), the City of Chicago ("City"), People of the State of Illinois ("AG") (collectively, "Government and Consumer Interveners" or "GCI"); Illinois Industrial Energy Consumers ("IIEC"); Multiut Corporation; Direct energy Services, LLC, Dominion Retail, Inc., Interstate Gas Supply of Illinois, Inc. and US Energy Savings Corporation, (collectively, the "Retail Gas Suppliers" or "RGS"); Constellation NewEnergy-Gas Division ("CNE-Gas"); Prairie Point Energy, L.L.C. d/b/a Nicor Advance Energy, L.L.C. ("NAE"); Environmental Law & Policy Center ("ELPC"); Vanguard Energy Services, L.L.C. ("VES"); and Utility Workers Union of America, AFL-CIO Local Union No. 18007 ("UWUA").

The following witnesses submitted testimony on behalf of the Staff of the Illinois Commerce Commission ("Staff"): Dianna Hathhorn (ICC Staff Exhibit 1.0; ICC Staff Exhibit 13.0), Bonita A. Pearce (ICC Staff Exhibit 2.0; ICC Staff Exhibit 14.0), Daniel G. Kahle (ICC Staff Exhibit 3.0; ICC Staff Exhibit 3.0-Supplemental Corrected; ICC Staff Exhibit 15.0 Corrected; Thomas L. Griffin (ICC Staff Exhibit 4.0; ICC Staff Exhibit 16.0 (Public and Confidential)), Janis Freetly (ICC Staff Exhibit 5.0; ICC Staff Exhibit 17.0); Sheena Kight-Garlisch (ICC Staff Exhibit 6.0; ICC Staff Exhibit 18.0); Mike Luth (ICC Staff Exhibit 7.0; ICC Staff Exhibit 19.0); Peter Lazare (ICC Staff Exhibit 8.0; ICC Staff

Exhibit 20.0 Revised), Cheri L. Harden (ICC Staff Exhibit 9.0; ICC Staff Exhibit 21.0); Dennis L. Anderson (ICC Staff Exhibit 10.0; ICC Staff Exhibit 22.0); Eric Lounsberry (ICC Staff Exhibit 11.0; ICC Staff Exhibit 23.0); and David Rearden (ICC Staff Exhibit 12.0 Revised; ICC Staff Exhibit 24.0 Corrected).

During the course of the proceeding, Staff proposed various adjustments and changes to the Companies' March 9, 2007 request. The Companies accepted certain of Staff's modifications and Staff withdrew others. A summary of Staff's final recommendations to the Commission in this proceeding for Peoples Gas and North Shore are attached hereto, respectively, as Appendix A and B. Also, attached as part of Appendix A and B is Staff's revised Revenue Requirement. For the reasons stated below, Staff's proposed adjustments should be adopted by the Commission.

B. Nature of Operations

1. Peoples Gas

2. North Shore

C. Test Year (Uncontested)

II. RATE BASE

A. Overview

B. Uncontested Issues

1. Original Cost Determination as to Plant Balances as of 9/30/06

Staff and the Companies agree as to the original cost findings regarding the Companies' plant as of the end of the fiscal year 2006 (September 30, 2006). Staff recommended that the $2,327,990,000 original cost for Peoples Gas and the

$369,442,000 original cost for North Shore of plant at September 30, 2006, reflected on the Companies' Schedules B-1, Line 1, Column D, be unconditionally approved as the original cost of plant. In their surrebuttal testimony, the Companies accepted Mr. Kahle's recommendation (North Shore/Peoples Gas Ex. LMK-3.0, pp. 5-6). Given Staff's recommendation regarding the original cost determination, Staff recommends the Commission's order state:

> It is further ordered that the $2,327,990,000 original cost for Peoples Gas and the $369,442,000 original cost for North Shore of plant at September 30, 2006, reflected on the Companies Schedules B-1, Line 1, Column D, is unconditionally approved as the original cost of plant.

(ICC Staff Exhibit 15.0 Corrected, pp. 21-22)

2. *Pro Forma* Capital Additions

In his corrected rebuttal testimony, Staff witness Kahle proposed adjustments to the pro forma plant additions the Companies had included in rate base. Mr. Kahle recommended the removal of costs which were only based upon 2007 capital budget additions. Mr. Kahle found those budgeted costs to not be known and measurable in accordance with 83 Ill. Adm. Code 287.40. (ICC Staff Exhibit 15.0, Schedules 15.2 N and P Corrected) As Mr. Kahle testified the mere adoption of a budget is not evidence that a project is reasonably certain to occur as is required by Section 287.40. (ICC Staff Exhibit 15.0 Corrected, p. 15) Mr. Kahle after reviewing the Companies' response to a data request did allow pro forma capital additions that were supported by ten months of actual expenditures and two months of estimated expenditures. He found those amounts to be known and measurable.

In their surrebuttal testimony, the Companies accepted Mr. Kahle's adjustments after Mr. Kahle in a data request response recognized and accepted Peoples Gas' cushion gas additions in the amount of $10.405 million. (North Shore/Peoples Gas Ex. SF-4.0, pp. 5-6). Staff and the Companies also agree on Staff's adjustment to Depreciation Expense. In his rebuttal testimony, Staff witness Kahle proposed adjustments to depreciation expense, the reserve for depreciation, and accumulated deferred income taxes related to the adjustments to pro forma plant additions (ICC Staff Exhibit 15.0, Schedules 15.2 N and P Corrected). In their surrebuttal testimony, the Companies accepted Mr. Kahle's adjustments (North Shore/Peoples Gas Ex. SF-4.0, pp. 5-6).

3. Capitalized Lobbying Expenses

In his direct testimony, Mr. Kahle proposed adjustments to the Companies' Gross Utility Plant for capitalized payroll associated with lobbying activities (ICC Staff Exhibit 3.0, Schedules 3.3 N and P). Mr.Kahle's adjustment was based upon the requirements of Section 9-244 of the Act which excludes lobbying expenses from the determination of any rate or charge. (ICC Staff Exhibit 3.0, pp. 11-12) In their rebuttal testimony, the Companies in order to narrow issues accepted Mr. Kahle's adjustments (North Shore/Peoples Gas Ex. SF-2.0, p. 5).

4. Capitalized City of Chicago Resurfacing Costs (PGL)[1]

5. ADIT - Gas Cost Reconciliation

6. AMT - Gas Charge Settlement

C. Plant

1. Capitalized Incentive Compensation

2. Hub Services (PGL) (To be addressed in Section V, below)

D. Reserve for Accumulated Depreciation and Amortization

1. GCI's Proposed Adjustments

2. Derivative Adjustments

E. Cash Working Capital

1. Gross Lag Methodology vs. Net Lag Methodology

In his corrected rebuttal testimony, Mr. Kahle proposes that the Companies' Cash Working Capital ("CWC") requirements be calculated using the gross lag methodology. The Commission has adopted the gross lag methodology in several previous dockets (most recently in AmerenCILCO, AmerenCIPS, and AmerenIP Docket Nos. 06-0070, 06-0071 and 06-0072 (Cons.). In the Ameren cases, the Commission rejected the Mr. Adams' (who was testifying on behalf of the Ameren Companies) use of the Net Lag Approach and adopted the Gross Lag Approach as proposed by Staff in calculating CWC (ICC Staff Exhibit 15.0, pp. 4-5). In his surrebuttal testimony, the Companies' witness Adams stated that he is not opposed to the use of the Gross Lag methodology to determine the CWC requirements for the Companies in these

[1] "PGL" = Peoples Gas. "NS" = "North Shore". Use of these acronyms in a parenthetical means the issue relates only to the referenced utility.

proceedings (North Shore/Peoples Gas Ex. MJA-3.0, p. 4) however Mr. Adams disagrees with Staff witness Kahle's calculation under that methodology.

2. Capitalized Expenditures and Treatment of Real Estate Taxes

In his corrected rebuttal testimony, Staff witness Kahle proposed adjustments to the CWC requirement calculated by the Companies. Staff proposed an adjustment of $622,000 for North Shore reducing its CWC requirement to negative $1,746,000. Staff also proposed an adjustment of $14,315,000 for Peoples Gas reducing its CWC requirement to $16,581,000 (ICC Staff Brief, Appendices A & B). Staff notes that some of the components of the CWC calculation may yet be subject to further adjustment pending Commission action (ICC Staff Exhibit 15.0, Schedules 15.1 N and P, pp. 2-4).

The Companies contest two aspects of Mr. Kahle's CWC calculation. The Companies contest (1) the treatment of capitalized payroll costs, and (2) the treatment of pass-through taxes and real estate taxes.

a. Cash Outlays for Capital Expenditures

The Companies failed to include capitalized payroll expenses in their CWC analysis. Mr. Kahle included capitalized payroll, pensions and benefits in the CWC requirement calculation because these items reflect cash outlays of the Companies' normal day-to-day operations (ICC Staff Exhibit 15.0, pp. 7-9) and "Cash Working Capital 'CWC' is the amount of funds required from investors to finance day-to-day operations…." (ICC Staff Exhibit 3.0. p. 3)

Mr. Kahle's inclusion of capitalized payroll, pensions and benefits in the CWC requirement calculation is consistent with a recent Commission order. In the Commission's Order for AmerenCILCO, AmerenCIPS, and AmerenIP the Commission found that “Staff’s analysis of this issue is correct” and the Commission therefore included “the capitalized portion of payroll expense [when] calculating CWC.”(Docket Nos. 06-0070, 06-0071 and 06-0072 (Cons.), (Order dated November 21, 2006, p. 36).

During cross examination, the Companies’ witness Adams admitted that payroll is a part of a company's day-to-day operations (September 10, 2007 TR., p. 297, Lines 1 - 5). Given that payroll is part of the Companies day to day operations it must be considered in the calculation of cash working capital in order to accurately determine the amount of funds necessary to fund day to day operations. In his surrebuttal testimony, Witness Adams argued that including capitalized payroll, pensions and benefits in the CWC requirement calculation was inappropriate because a company earns a return on capitalized items and recovers the cost of capitalized assets through depreciation (North Shore/Peoples Gas Ex. MJA-3.0, p. 11, 223-226). In response Staff would point out that Mr. Kahle did not, however, propose an adjustment to these capitalized items, but rather proposed an adjustment to the CWC in order to make it reflective of day-to-day cash outlays. In conclusion when the company incurs a cost like payroll, cash is required regardless of whether the cost is expensed or capitalized. Therefore, the CWC requirement should be computed by applying lead and lag days to the Companies day-to-day cash outlays including capitalized payroll.

b. Treatment of Pass-Through Taxes and Real Estate Taxes

Staff and the Companies disagree on the treatment of pass-through taxes and real estate taxes in the CWC calculation. Included in the “Taxes Other Than Income Taxes” component of the Companies’ CWC analysis are various “pass-through” taxes and real estate taxes. Staff believes that “pass-through” taxes should not be included in the CWC calculation because pass-through taxes do not impact the financing of day to day operations. These taxes are collected by the Companies from customers and are then passed on to the appropriate taxing body. They have no impact on base rates. (ICC Staff Exhibit 15.0 Corrected, p. 11) Staff further believes that real estate taxes deserve separate consideration because the Companies' real estate taxes have more than a year in lead time before payment.

Mr. Adams treatment of real estate taxes and pass through taxes is inconsistent. In his workpaper for Peoples Gas, Mr. Adams included over $224 million of taxes to calculate lead days. $206 million of the $224 million of taxes were "pass-through" taxes. As previously discussed, "Pass-through" taxes are included in a customer's bill, collected by the utility and remitted directly to the taxing authority. As such, the impact on the Companies' cash flow is that $206 million of "pass-through" taxes represent cash-on-hand for a short period with no associated revenue lag time. While Mr. Adams calculated lead days using the short lead times and large amounts of "pass-through" taxes, he applied the lead days to only $17.643 million of Taxes Other Than Income Taxes ("Other Taxes"). The effect of including over $206 million of "pass-through" taxes in the lead days calculation unfairly skews the weight of the lead days toward the shorter lead times and greater amounts of the "pass-through" taxes. (ICC Staff Exhibit 15.0 Corrected, p. 11)

Given Mr. Adams inclusion of pass through taxes, Staff witness Kahle explained that real estate taxes should be treated separately in the CWC requirement calculation appropriately account for the more than one-year lead time for real estate tax payment and the unfair weighting of pass through taxes. (ICC Staff Exhibit 15.0 Corrected, pp.

10-13). In his surrebuttal testimony, the Companies witness Adams stated that "pass-through" taxes have an impact on the Companies' cash flows and as such should be considered in the CWC analyses along with the remaining Other Taxes (North Shore/Peoples Gas Ex. MJA-3.0, p. 2). Mr. Adam's argument should be rejected. As mentioned above, it is not supported by his own work. Mr. Adam's workpapers show that Mr. Adams applied his lead days to only $17.643 million of Taxes Other Than Income Taxes (i.e. he excluded the pass through taxes in his final calculation. (ICC Staff Exhibit 15.0 Corrected, p. 11). If "pass-through" taxes in fact had an impact on cash flows, he would have included "pass-through" taxes in his final calculation of the CWC requirement. Since they do not, the pass through taxes were excluded in the final calculation and should have been excluded in calculating lead days.

Staff recommends, subject to any final adjustments to the components of Staff's CWC calculation due to any change in the final revenue number, that the Commission should reduce North Shore's CWC requirement by $626,000 to negative $1,750,000 and reduce Peoples Gas' CWC requirement by $14,298,000 to $16,598,000 (ICC Staff Exhibit 15.0, Schedules 15.1 N and P, p. 1).

Staff further recommends that the Commission's order expressly;

- adopt the Gross Lag Methodology for calculating the CWC requirement as presented in ICC Staff Exhibit 15.0, Schedules 15.1 N and P, p. 1,
- allow separate treatment for the effect of lead days for real estate taxes in the CWC requirement calculation as presented in ICC Staff Exhibit 15.0, Schedules 15.1 N and P, pp. 1 and 4, and
- include capitalized payroll in the CWC requirement calculation as presented in ICC Staff Exhibit 15.0, Schedules 15.1 N and P, p. 3.

F. Gas in Storage

1. Working Capital

In its rebuttal testimony, Staff recommended a reduction to the Companies' requested working capital allowance associated with their gas in storage amounts. Specifically, Staff recommended a reduction of $13,549,797 to Peoples Gas' requested $86,667,000 working capital allowance associated with gas in storage due to Peoples Gas maintaining 6,896,183 Mcf of storage gas in excess of normal levels. (ICC Staff Exhibit 23.0, pp. 6-7) Staff also recommended a reduction of $1,422,772 to North Shore's requested $10,507,000 working capital allowance associated with gas in storage due to North Shore maintaining 866,543 Mcf of storage gas in excess of normal levels. (Id., pp. 15-16)

Staff recommended reductions in the requested working capital allowance for both Companies to offset the excessive amounts of storage gas both Companies maintained in the test year due to warmer than normal weather conditions. Staff concluded that the gas storage volume the Companies' requested to be included in their test years, and thus the revenue requirement, greatly exceeded their historical storage volumes. (Id., pp. 6 and 15) Staff arrived at this conclusion through its review of Peoples Gas' and North Shore Gas' historical gas storage volumes. Peoples Gas' requested test year gas volume (Fiscal Year 2006: October 1, 2005 to September 30, 2006) was on average more than 4 Bcf[2] higher than the prior two fiscal years (Fiscal 2005 and 2004) and more than 10 Bcf higher than Fiscal Years 2003 and 2002. (ICC Staff Exhibit 11.0, pp. 7-8 and ICC Staff Exhibit 11.0, Schedule 11.3P) North Shore's

[2] Bcf is equal to 1,000,000 Mcf or 1,000,000,000 cubic feet.

requested test year gas storage volume was about 900,000 Mcf higher than the storage volume from the prior 4 fiscal years. (Id., p. 25)

The Companies explained their excess gas in storage as a result of warmer than normal weather conditions. (NS/PGL Ex. TZ-2.0, p. 74, lns. 1640-1642) The Companies indicated that the winter of 2006[3] was the fifth warmest on record, and that January 2006 was the warmest January on record. (Id.) The Companies concluded that these warmer than normal temperatures contributed to the increased test year storage volumes maintained by both Companies. (Id. at lns. 1644-1646)

Thus, based on the Companies' own information Staff concluded that the storage gas volumes that the Companies maintained during the test year were higher than normal, and therefore warranted a reduction to represent normal conditions. (Staff Ex. 23.0, pp. 8 and 17) Staff also noted that the revenue requirement determined in the instant proceeding should be based upon normal conditions. (Id.) The information provided by the Companies came in response to Staff data request ENG 7.05, which showed a comparison of the number of heating degree days assumed for the test year versus the actual number of degree days for fiscal years 2002 through 2006. The data showed that none of the historical fiscal years provided a match for the heating degree days the Companies assumed as part of the normalized test year. (Id., pp. 9 and 17-18) Thus an adjustment was necessary.

Based upon all of the above information, Staff concluded that the Companies requested amounts were not based on normal conditions and instead were based upon

[3] The Companies' test year of October 1, 2005, through September 30, 2006, (Fiscal 2006) included the winter of 2006.

warmer than normal weather conditions that contributed to the Companies maintaining a larger than normal volume of storage gas (Id., pp. 8 and 17)

As a result of this conclusion, Staff requested that the Companies provide the storage volumes they had assumed would occur had a normal year occurred in the test year. (Id., pp. 9 and 18) Staff used this information, provided in response to Staff data request ENG 7.10, to calculate the volume of gas the Companies would have maintained in the test year under normal conditions; Staff then used that normalized volume to determine the appropriate working capital allowance for gas in storage. (Id., and Staff Ex. 23.0, Schedules 23.2P and 23.2N) This calculation indicated that Peoples Gas needed to reduce its gas in storage volume by 6,896,183 Mcf, which forms the basis for Staff's recommended adjustment of $13,549,797. (ICC Staff Ex. 23.0, p. 9, and ICC Staff Ex. 23.0, Schedule 23.1P) Staff performed the same calculations for North Shore Gas' storage volumes, and concluded that North Shore needed to reduce its gas in storage volume by 866,543 Mcf, which forms the basis for Staff's recommended adjustment of $1,422,772. (ICC Staff Exhibit 23.0, p. 18 and ICC Staff Exhibit 23.0, Schedule 23.1N)

The Companies have not accepted Staff's recommendation regarding their allowed working capital allowance for gas in storage. However, the Companies did not provide any surrebuttal testimony to dispute any of Staff's assertions or conclusions. Instead, the Companies, in their rebuttal testimony, merely provided additional detail to clarify various areas of concern that Staff raised in its direct testimony regarding the gas storage inventory volumes requested by the Companies as part of their working capital allowance for gas in storage. (North Shore/Peoples Gas Ex. TZ-2.0, pp. 71-82)

Staff's review in Staff Exhibit 23.0, Rebuttal Testimony of Eric Lounsberry, demonstrated that the Companies requested working capital allowance for their gas in storage amounts involved storage volumes that were significantly higher than historical levels and that the test year volumes were overstated due to the warmer than normal weather during the test year. The Companies did not dispute Staff's conclusions in their surrebuttal testimonies. Therefore, Staff's recommended reduction to working capital allowance for gas in storage for both Companies, which was based upon the Companies expected test year storage activity under normal weather conditions, should be accepted.

2. Accounts Payable

In his corrected supplemental direct testimony, Mr. Kahle proposed adjustments to the gas in storage the Companies had included in rate base. Mr. Kahle's adjustments removed costs which were not financed by investors and were not supported by actual expenditures. These costs were supported by accounts payable, and as such, were funded by vendors and therefore, the Companies should not earn a return on that gas in storage. (ICC Staff Exhibit 15.0 Corrected, pp. 17-18; Id., Schedules 15.3 N and P, p. 1).

In his Supplemental Rebuttal Testimony, Companies witness Fiorella agreed that to the extent that the Utilities have not paid for a good or service that has been received, an accounts payable exists on the Utilities' books, and the vendor has provided temporary financing. Mr. Fiorella went on to argue that no adjustment should be made because the account payable no longer existed; however, he did not contend that the accounts payable did not exist during the test year (North Shore/Peoples Gas Ex. SF-3.0, pp. 2-3). In fact, the amount of the gas in storage adjustment was calculated using accounts payable balances supplied by the Companies in a data request response (ICC Staff Exhibit 15.0, Schedules 15.3 N and P, p. 2).

Also in response to Mr. Fiorella's argument that the accounts payable no longer existed at the end of the testy year, Mr. Kahle pointed out that as certain accounts payable are paid; other accounts payable are created in the normal gas purchasing cycle. Therefore, a portion of gas in storage would continue to be financed by vendors through accounts payable (ICC Staff Exhibit 15.0, p. 19) and the Companies at no time offered that any other items that might have expired since the end of the test year should be excluded; such as, the gas in storage that was reported on the Companies' Schedule B-1 which may have been withdrawn and consumed by ratepayers since the end of the test year. (ICC Staff Exhibit 15.0 Corrected, p. 19)

Mr. Fiorella made the additional argument that no adjustment related to accounts payable should be made to gas in storage because the Companies had filed a historic test year (North Shore/Peoples Gas Ex. SF-3.0, p.-3); however, the accounts payable for gas in storage should received the same treatment as accounts payable for materials and supplies. (ICC Staff Exhibit 15.0 Corrected, pp 18-19)

In further support for Staff's adjustment, in the Companies' previous rate cases, Docket Nos. 95-0031 and 95-0032 Proposed general increase in rates for gas service (Orders Entered November 8, 1995, pp. 5-6), the Commission accepted an adjustment to reduce Gas in Storage by associated accounts payable and the Commission applied the same treatment in the following cases:

- Docket No. 04-0779, Nicor Gas Company, Proposed general increase in natural gas rates (Section 285.2005 filing: Schedule B-1.1);
- Docket No. 93-0183, Illinois Power Company, Proposed general increase in gas rates (Order Entered April 6, 1994, p 58); and
- Docket No. 95-0219, Northern Illinois Gas Company, Proposed general increase in rates for gas service (Order Entered April 3, 1996, p 27).

(ICC Staff Exhibit 15.0 Corrected, p. 20)

Staff recommends that the Commission adopt staff's adjustment for accounts payable associated with storage gas as presented on Schedules 15.3 N & P by reducing Gas in Storage included in rate base for the related accounts payable by $6,098,000 for North Shore and by $26,727,000 for Peoples Gas.

G. OPEB Liabilities and Pension Asset/Liability

Other Post Employment Benefits ("OPEB") liability is the employer's obligation for post retirement benefits generally, such as health care, life insurance, tuition assistance and other types of post retirement benefits outside of a pension plan. In the instant proceeding, the accrued OPEB liability represents a cost-free source of capital and should be treated for ratemaking purposes as a reduction of rate base (ICC Staff Exhibit 14.0, p. 21, lines 470 – 473).

Mr. David J. Effron, a witness for the AG, City of Chicago and CUB proposed an adjustment in direct testimony (GCI Exhibit 1.0, pp. 12-13, lines 254 – 292) to reduce utility rate base by the amount of accrued OPEB liabilities, $4,074,000 for North Shore and $31,570,000 for Peoples Gas, respectively. Mr. Effron proposed this adjustment based on his understanding that the accrued liabilities represent expenses accrued in excess of actual payments for OPEB. He based this adjustment on his determination that the Commission has made such adjustments in prior proceedings in which it was shown that the utility controlled the ratepayer-supplied OPEB funds.

Ms. Linda Kallas, a witness for the Companies, disagreed with Mr. Effron's adjustment. Ms. Kallas noted that the Companies did not increase rate base by the pension asset. She argued that under Mr. Effron's rationale, the Companies should include the pension asset in rate base if they reflect the OPEB liability, as Mr. Effron proposes (North Shore/Peoples Gas Ex. LK-2.0 REV, p. 13, lines 272 – 280).

Staff witness Ms. Pearce in her rebuttal testimony (ICC Staff Exhibit 14.0, pp. 20 - 24), agreed with Mr. Effron's adjustment to reduce utility rate base for the accrued OPEB liability. Additionally, Ms. Pearce disagreed with Companies' witness Ms. Kallas regarding her assertion that if utility rate base were reduced by accrued OPEB liability, the pension asset/liability should also be reflected in rate base.

For ratemaking purposes, a rate base reduction of the accrued liability associated with OPEB is appropriate to the extent that the test year obligation is unfunded or partially funded. The accrued liability represents the aggregate OPEB costs recognized in the income statement which has not been paid to a third party. Ratepayers have supplied funds for future obligations; therefore, a source of cost free capital has been provided to the utility which should be recognized in the revenue requirement as a reduction from rate base. (Id, pp. 21-22)

Ms. Kallas asserted that if Mr. Effron's proposal is adopted by the Commission, then an adjustment for the net pension assets/liabilities should also be added to the rate base of each utility (North Shore/Peoples Gas Ex. LK-2.0 REV, p. 13, lines 272-280). Her assertion is inconsistent with ratemaking theory because the pension asset of

Peoples and the pension liability of North Shore do not represent elements of rate base that should impact the return to shareholders. That is because the respective asset/liability was not created with funds supplied by shareholders. Because these amounts were not provided by shareholders, shareholders do not need to earn a return on such amounts. (ICC Staff Exhibit 14.0, p. 22)

The Commission addressed the treatment of OPEB liability in the most recent Northern Illinois Gas Company ("Nicor") rate proceeding, Docket No. 04-0779 and in the Ameren Companies' latest request for an increase in delivery service tariffs ("DST"), Docket Nos. 06-0070, 06-0071, and 06-0072, Consolidated (AmerenCILCO, AmerenCIPS, AmerenIP) Order dated November 21, 2006 at page 27, as cited by Mr. Effron in direct testimony (GCI Exhibit 1.0, p. 13, lines 278 – 283). In these cases, the Commission found that the OPEB liability should be treated as a reduction of utility rate base. (ICC Staff Exhibit 14.0, p. 23)

The Commission has also addressed the issue of pension asset treatment in recent ratemaking proceedings. Specifically, in Docket No. 04-0779, and in its previous rate case (Docket No. 95-0219), Nicor requested to increase utility rate base for the amount of a prepaid pension asset. In both cases the Commission found that the pension asset was created by ratepayer-supplied funds, not by shareholder-supplied funds. The Commission concluded that ratepayers should not be denied the benefits associated with the previous overpayment for pension expense which they funded. Accordingly, the Commission concluded that the pension asset should be eliminated from rate base. (ICC Staff Exhibit 14.0, p. 23)

H. ADIT (Derivative Adjustments from Uncontested and Contested Issues)

III. OPERATING EXPENSES

A. Overview

B. Uncontested Issues

1. Storage Expenses (Compressor Station Fuel Expenses) (PGL)

2. Distribution Expenses

a. Non-Payroll Expenses Inflation

Staff witness Pearce proposed removing from each Company's operating expenses a pro forma adjustment to reflect 2007 inflation for non-payroll expenses. Ms. Pearce's recommendation was made for the following reasons: Section 287.40 (83 Ill. Adm. Code 287.40 does not allow pro forma adjustments to the test year for the application of inflation factors in lieu of a particularized study of individual expense components and the Companies' pro forma adjustment was not known and measurable. (ICC Staff Exhibit 2.0, pp. 3-4)

The Companies in their rebuttal testimony, in order to narrow contested issues, did not contest Ms. Pearce's adjustment. (North Shore/Peoples Gas Ex. SF-2.0, p. 5)

b. Customer Installation Expenses (NS)

Staff witness Pearce proposed an adjustment for North Shore only to remove from North Shore's test year operating expenses an amount which corrected an error from 2005. As Ms. Pearce explained, the correction of the error in 2006 caused the balance of expense in account 879 to be overstated by $175,000. Without Staff's adjustment the test year amount for the account would not be reflective of normal operations. (ICC Staff Exhibit 2.0, p. 20)

The Company in rebuttal testimony, in order to narrow contested issues, did not contest Ms. Pearce's adjustment. (North Shore/Peoples Gas Ex. SF-2.0, p. 5)

c. City of Chicago Resurfacing Expenses (PGL)

3. Customer Accounts Expenses (Uncollectible Accounts Expenses)

Staff witness Hathhorn proposed an adjustment to the pre-increase amounts of uncollectibles expense, but withdrew it in rebuttal testimony as it repeated Company calculations. (Staff Exhibit 13, p. 6)

4. Customer Service and Information Expenses

a. "Advertising" Expenses

In his direct testimony, Mr. Kahle proposed adjustments to the Companies' Advertising Expenses for expenses that are of a promotional, goodwill or institutional nature (ICC Staff Exhibit 3.0, Schedules 3.2 N and P) given that Section 9-225 of the Act prohibits them from being considered for the purposes of rates. (ICC Staff Exhibit 3.0, pp. 10-11) In their rebuttal testimony, the Companies in order to narrow contested issues accepted Mr. Kahle's adjustments (North Shore/Peoples Gas Ex. SF-2.0, p. 5).

b. Dues and Memberships Expenses (PGL)

In his direct testimony, Mr. Kahle proposed adjustments to the Peoples Gas Dues and Membership Expenses for membership dues associated with such organizations as the Chicago Club, the Mid-America Club and University Club of Chicago since these membership dues represent promotional and goodwill practices (ICC Staff Exhibit 15.0, Schedule 3.4 P) which Mr. Kahle found unnecessary in providing utility service. In its rebuttal testimony, the Company in order to narrow contested issues accepted Mr. Kahle's adjustments (North Shore/Peoples Gas Ex. SF-2.0, p. 5).

5. Administrative & General Expenses

a. Civic, Political, and Related Activities Expenses

In Schedules 1.9 P and N, Staff disallowed $80,000 and $11,000, respectively, in expenses allocated to the Companies from Peoples Energy Corporation ("PEC") for civic, political and related activities since these expenses are not eligible for rate recovery according to Section 9-224 of the Act, which bars any expenses expended for political activity or lobbying from rates. (Staff Exhibit 1, pp. 12-13) The Companies did not contest these adjustments. (North Shore/Peoples Gas Ex. SF-2.0, pp. 4-5)

b. Employee Recreation Expenses

In Schedules 1.14 P and N, Staff disallowed $54,000 and $7,000 in payment of employee recreation expenses allocated to the Companies from PEC for professional sporting event outings, picnics, and other social events not necessary to provide utility services. (Staff Exhibit 1, p. 18)

c. Corporate Rebill of Income Tax Penalties

In Schedules 1.13 P and N, Staff disallowed $35,000 and $5,000, respectively, in payments of a federal income tax penalty allocated to the Companies from PEC, since generally, these types of penalties are not eligible for rate recovery as the charges were incurred for violation of a regulatory statute. (Staff Exhibit 1, pp. 17-18) The Companies did not contest these adjustments. (North Shore/Peoples Gas Ex. SF-2.0, pp. 4-5)

d. Lobbying Expenses

In his direct testimony, Mr. Kahle proposed adjustments to the Companies' Operating Expenses payroll associated with lobbying activities (ICC Staff Exhibit 3.0, Schedules 3.3 N and P) since such expenses are prohibited from rate recovery in Section 9-224 of the Act. In their rebuttal testimony, the Companies in order to narrow contested issues accepted Mr. Kahle's adjustments (North Shore/Peoples Gas Ex. SF-2.0, p. 5).

e. Executive Perquisites Expenses

Staff witness Pearce proposed an adjustment to remove from the test year executive perquisites for the Companies. Based upon the Companies' response to a data request the executive perquisites included reimbursements to officers and high level executives for: auto allowances, supplemental life insurance, executive physicals, and flexible perquisite allowances to cover excess liability insurance, financial counseling and home office equipment. Ms. Pearce found these expenses to be discretionary and unnecessary for the provision of utility service. She further noted that the perquisites are awarded to a few top executives in addition to salaries and other benefits. (ICC Staff Exhibit 2.0, p. 19)

The Companies in their rebuttal testimony, in order to narrow contested issues, did not contest Ms. Pearce's adjustment. (North Shore/Peoples Gas Ex. SF-2.0, p. 5)

f. Termination Costs (PGL)

Staff witness Pearce proposed an adjustment for Peoples Gas to remove termination allowances. Ms. Pearce explained that her adjustment removes from the test year expense which is not reflective of normal utility operations. (ICC Staff Exhibit 2.0, pp. 20-21)

The Company in rebuttal testimony, in order to narrow contested issues, did not contest Ms. Pearce's adjustment. (North Shore/Peoples Gas Ex. SF-2.0, p. 5)

g. Salaries and Wages Expenses

Ms. Pearce proposed an adjustment for the Companies for salaries and wages expenses to take into account a correction which the Companies made to the underlying calculation for O & M union wage and nonunion merit increases for 2006 and O & M union wage and nonunion merit increases for 2007. (ICC Staff Exhibit 2.0, pp. 21-22)

The Companies in their rebuttal testimony did not contest Ms. Pearce's adjustment. (North Shore/Peoples Gas Ex. SF-2.0, p. 5)

h. Medical and Insurance Expenses

i. Rate Case Expenses

North Shore Gas originally proposed rate case expense of $954,000 and Peoples Gas proposed rate case expense of $1,212,000 (ICC Staff Ex. 4.0, Schedule 4.1N and 4.1P). In his direct testimony, Staff witness Griffin recommended a five year amortization period for rate case expenses rather than the three year period proposed by the Companies. (ICC Staff Ex. 4.0, pp. 6-7) Mr. Griffin testified that his five year amortization period was based upon the average number of years between the most recent five rate cases. The Companies proposed a three year amortization period based upon the average number of years between the most recent ten rate cases. (Id., p. 6) Mr. Griffin testified that the five earliest of the ten rate cases used in the Companies' calculation were filed during periods of high inflation. Mr. Griffin concluded that excluding from the analysis the five earlier rate cases results in an amortization period that is a better indicator of when the Companies are more likely to file the next set of rate cases. (Id.)

In an attempt to narrow the issues, Company witness Mr. Fiorella's surrebuttal testimony indicated that the Companies no longer contested Mr. Griffin's five year amortization period. (North Shore/Peoples Gas Ex. SF-4.0, p. 5)

With regard to the total amount of total rate case expense, Staff witness Griffin testified in his rebuttal testimony that Peoples Gas had supported $2,956,220 in total rate case expense and North Shore had supported $2,169,800 in total rate case expense. (ICC Staff Ex. 16.0, p. 6) Using a five year amortization period, Mr. Griffin recommended a rate case expense for Peoples Gas equal to $591,244 (Id., Schedule

16.1P, page 2 of 2) and recommended a rate case expense for North Shore equal to $433,960 (Id., Schedule 16.1N, page 2 of 2).

In order to narrow the issues further, the Companies in surrebuttal testimony did not contest Mr. Griffin's rate case expense for either Company. (North Shore/Peoples Gas Ex. SF-4.0, p. 5). The Companies also abandoned a proposal made in rebuttal testimony to include the unamortized portion in rate base. (Id.) Mr. Griffin opposed the inclusion in rate base of any unamortized balance of rate case expense. (ICC Staff Ex. 16.0, p. 2)

In conclusion, the Companies and Staff agree that the annual amortization for rate case expense for North Shore and Peoples Gas should be $433,960 and $591,244 respectively based upon a five year amortization period with no unamortized balance in rate base.

j. Franchise Requirements Expenses (NS)

k. PEC Officer Costs and Directors Fees

In Schedules 1.12 P and N, Staff disallowed $702,000 and $100,000, respectively, to reallocate a reasonable portion of Peoples Energy Corporation ("PEC") officer costs and director fees to PEC, the Companies' parent company at the time, rather than the Companies. (Staff Exhibit 1, pp. 15-17) The Companies accepted the adjustments in surrebuttal testimony in order to narrow the contested issues. (North Shore/Peoples Gas Ex. SF-4.0, p. 3)

Staff also recommended, due to the errors found in allocations from PEC of this adjustment, the civic, political, and related activities (III., B., 5., a), income tax penalties (III., B., 5., c.), and recreation expenses (III., B., 5., b.) adjustments allocated from PEC, that the Commission emphasize to the Companies and put them on notice that their affiliate transactions must be in accordance with the Uniform System of Accounts for Gas Utilities (Il. Adm. Code 505), particularly General Instruction 14, which states

> **Transactions with associated companies.** Each utility shall keep its accounts and records so as to be able to furnish accurately and expeditiously statements of all transactions with associated companies. The statements may be required to show the general nature of the transactions, the amounts involved therein and the amounts included in each account prescribed herein with respect to such transactions. Transactions with associated companies shall be recorded in the appropriate accounts for transactions of the same nature. (Staff Exhibit 1, p. 20)

The Companies did not contest Staff's recommendation.

6. Taxes Other Than Income Taxes (Personal Property Taxes)

7. Income Taxes (Interest Synchronization)

C. Contested Issues

1. Storage Expenses

a. Crankshaft Repair Expenses (PGL)

Staff recommended a reduction to Peoples Gas' operating and maintenance expense ("O&M") due to a non-recurring expense associated with the repair to Peoples Gas' gas compressor. Specifically, Staff determined that Peoples Gas O&M levels should be reduced by $136,000 to account for the non-recurring experience of the gas compressor repair (ICC Staff Exhibit 23.0, p. 20)

Peoples Gas witness Kallas testified that the primary reason for a $547,000 increase in its O&M associated with its Underground Storage Expense-Maintenance was the failure of a bearing in a large gas compressor that damaged its crankshaft whose cost was $546,000. (Peoples Ex. LK-1.0) Staff's review of the circumstances associated with this type of repair demonstrated that the expense associated with compressor repair was a non-recurring expense, and all of the cost associated with the repair should be disallowed.

Staff's determined that compressor repair was non-recurring because Peoples Gas' response to Staff data request ENG 6.60 indicated that the expected life of the gas compressor was virtually indefinite and was only limited by the ability to obtain replacement parts. (ICC Staff Exhibit 11.0, p. 32) Next, Peoples Gas indicated that over the past 20 years, Peoples Gas had never experienced a major repair whose magnitude was similar to the crankshaft repair that took place in 2006. (Id., pp. 32-33)

Peoples Gas indicated that it did not expect to incur major repairs with its large gas compressors in the foreseeable future. (Id., p. 33) Peoples Gas also indicated that a technical report titled "Crankshaft Protection: Guidelines for Operators of Slow Speed Integral Engine/Compressors" showed the approximate average probability of incurring a fractured crankshaft is 0.00098 per year and when that probability was applied to Peoples Gas' six compressors that probability indicated an expected frequency of crankshaft failure of once in 170 years. (Id.) Further, Peoples Gas installed electronic bearing temperature sensors in its two largest compressors and programmed those compressors to automatically shut-down if the bearing temperatures exceed specified limits. (Id.) Peoples Gas indicated that these sensors should even further reduce the likelihood of re-occurrence of the same type of failure. (Id.) Based on this information, Staff determined that the expense associated with the gas compressor repair was a non-recurring expense and that the expense should be disallowed. (Id., p. 34)

Peoples Gas indicated that it agreed that the repair of the gas compressor might be a single "non-recurring" event, but said one should consider the scope of Peoples Gas' distribution operations and that given the span of those operations, it is likely to experience different non-recurring events each year. (North Shore/Peoples Gas Ex. SF-2.0, p. 12) Instead of accepting Staff's recommendation to disallow all of the $546,000 expense associated with the repair of the gas compressor, Peoples Gas accepted the recommendation of David Effron who proposed amortizing this expense over four years and reduced the O&M expense amount by $410,000. (GCI Ex. 2.0, pp. 32-33)

However, in response to Staff data request ENG 8.02, Mr. Effron agreed with Staff's conclusion that the compressor repair was a non-recurring item. (ICC Staff Exhibit 23.0, pp. 19-20) Further, Mr. Effron indicated that an utility's actual expenses in a test year should be adjusted to reflect, among other things, the elimination of any abnormal or non-recurring items in order to reflect normal operations in the determination of revenue requirements. (GCI Ex. 2.0, p. 21) Therefore, Staff continued to recommend the removal of all of the O&M expense associated with the gas compressor repair. The valuation of that adjustment is the difference between Staff's recommendation of $546,000 and the $410,000 amount that Peoples Gas agreed upon with GCI, or $136,000. (ICC Staff Exhibit 23.0, p.20)

No party disputes Staff's conclusion that Peoples Gas' repair of the gas compressor during the test year was a non-recurring event. The only remaining issue is whether the expense associated with this non-recurring event should be amortized or disallowed. Peoples Gas' main reason for disagreeing with Staff's proposal to disallow the compressor repair cost is the possibility that other non-recurring expenses will occur each year. However, Peoples Gas provided no support for this statement or any examples that Peoples Gas historic non-recurring expenses are in any fashion equivalent in magnitude to the costs associated with repairing the gas compressor. Further, GCI witness Effron's testimony (i.e. that a utility's actual expenses in a test year should be adjusted to reflect, among other things, the elimination of any abnormal or non-recurring items in order to reflect normal operations in the determination of revenue requirements) on its own provides a basis for the removal of non-recurring expenses. Therefore, Staff's recommendation to disallow all of the expenses associated with the compressor repair due to its non-recurring nature should be accepted.

b. Hub Services (PGL) (To be addressed in Section V, below)

2. Customer Accounts Expenses (Collection Agency Fees)

In Schedules 13.8 P and N, Staff disallows $1,770,000 and $76,000, respectively, representing the applicable Company's proposed increase to normalize test year collection agency fees, since the evidence reflects that the unadjusted test year expense is more likely to recur in the future than each Company's calculated increase. (Staff Exhibit 13, p. 6) The Companies contend that actual 2006 collection expenses were lower than normal due to the gas charge settlement, and propose a normalization adjustment to account for the alleged impact of the Settlement Agreement on collection costs. (Peoples Gas Ex. SF-1.0, p. 28, lines 604-606; North Shore SF-1.0, p. 26, lines 573-575) As indicated in the Final Order entered by the Commission on March 28, 2006, in Docket No. 01-0707 ("01-0707 Order"), the Companies entered into a Settlement Agreement with certain parties to resolve certain gas charge reconciliation proceedings. As part of the Amendment and Addendum to the Settlement Agreement (attached as an Exhibit to the 01-0707 Order), the Companies agreed to forgive certain outstanding debt and not pursue collection of those amounts. However, the Companies' historical expense experiences and the current trend of post test year collection agency fees do not support their contention. (Staff Exhibit 1, pp. 8-9)

In North Shore/Peoples Gas Ex. LK-2.0, pages 5-6, the Companies disagree with Staff's disallowance for the proposed pro-forma increase in collection agency fees. The Companies state that not only are 2006 fees understated due to the Settlement Agreement, but 2007 fees as well. (North Shore/Peoples Gas Ex. LK-2.0, page 5, lines 94-96) However, the evidence shows that not only are the 2006 expense levels lower than the Companies' request, the trend of lower collection agency fees than in prior years continues presently in 2007.

Using the Companies' responses to Staff data request DLH-23.01(Peoples/North Shore Cross Hathhorn Exhibit #6), Staff summarized the record evidence as follows:

Table 1	Peoples Gas	North Shore
Updated 2007 Annualized Post Test Year Fees	$736,000	$22,000
2006 Test Year Fees	$1,132,000	$29,000
Company Requested Fees	$2,902,000	$105,000

(Staff Exhibit 13, p. 9)

The Companies explain in DLH-23.01that it is not uncommon for collections to take place several years after the bill is turned over to a collection agency. The Settlement Agreement affected accounts through September 30, 2005. The Companies may be correct that at some unknown point in time in the future, its collection agency fees may eventually rise back to the pre-settlement level. However, due to the lag in collections, and resulting fees incurred, it is clear that the 2006 and 2007 expenses are far below the 2004 and previous years' amounts. Therefore, for the period of time the rates from the instant proceeding will be in effect, the Companies' proposed average based on the 2003 through 2005 experience is inappropriate and overstates the expected collection agency fees going forward. (Staff Exhibit 13, p. 10)

The Companies also disagrees that its adjustment represents an attempt to collect costs incurred from the Settlement Agreement. (North Shore/Peoples Gas Ex. LK-2.0, page 6, beginning line 123) The Companies' opinion appears to be derived from its understanding of the intention of the agreement. "[T]his adjustment follows the intent of the agreement to eliminate all effects of the settlement….This is no different than any other adjustment to historical costs that are impacted by unusual activity." *Id.* line 131-132. Staff notes that the Companies' adjustments are not "any adjustment for unusual activity" as they were borne out of the Companies' conduct and settlement of the issues in Docket No. 01-0707. The settlement represents, at least in part, the return to ratepayers of costs that the Companies should not have recovered as prudently incurred costs. Thus, the Companies' adjustment to "eliminate all effects of the settlement" with respect to uncollectibles has the effect, contrary to the intent of the settlement, to treat all costs as prudently incurred costs. (Staff Exhibit 13, pp. 10-11)

3. Administrative & General Expenses

a. Injuries and Damages Expenses

Staff witness Griffin proposed an adjustment to normalize injuries and damages expense. Peoples Gas proposed an accrual of $6,192,000 (ICC Staff Ex. 4.0, Schedule 4.4P, page 1 of 2) and North Shore proposed an accrual of $477,000. (Id., Schedule 4.4N, page 1 of 2). Mr. Griffin testified that the Companies' proposed accruals represented estimated amounts set aside for future claim payments. (Id., p. 8) Since the annual accruals can vary greatly from one year to the next, it is more appropriate to normalize the expense for ratemaking purposes. (Id.) Mr. Griffin calculated his normalized expense by examining the five year period from 2002 to 2006 and computing an average percentage of claims paid against the annual accrual. Mr. Griffin then took that percentage and applied it against the accrual for 2006 Injuries and Damages.

Mr. Griffin in his rebuttal testimony revised his adjustment for injuries and damages to account for an inadvertent error and to include payments made in 2002 through 2006 for amounts under $100,000. (ICC Staff Ex. 16.0, pp. 6-7) Mr. Griffin's rebuttal position incorporated a corrected normalized adjustment presented in the testimony of the Companies' witness Kallas in schedules 16.2P and 16.2N.

The Companies contest Mr. Griffin's adjustment on the basis that given the "relative closeness" of the expense there is no good reason to normalize Injuries and Damages expense. (North Shore/Peoples Gas Ex. LMK-3.0, p. 5) The Companies also argue that Mr. Griffin did not explain why he chose to use five years to normalize the expense. (Id.) The Commission should disregard the Companies' arguments. As Mr. Griffin explained in his rebuttal testimony the difference between the Companies' proposal and his proposal is significant. The difference between normalized and actual injuries and damages expense is 14% for Peoples Gas and 22% for North Shore. (ICC Staff Ex. 16.0, p. 7)

In response to the Companies argument that Mr. Griffin gave no reason for choosing a five year period, i.e. 2002 through 2006, Staff would point out that the Commission used a five year period when examining injuries and damages expenses in the Ameren Illinois Utilities' recent rate cases (AmerenCILCO, AmerenCIPS, and AmerenIP electric rate cases, ICC Docket Nos. 06-0070/06-0071/06-0072, Consolidated) . Mr. Griffin used the Ameren order as a guide by also using a five year period in his analysis.

The Companies also maintain that the year 2002 should be excluded from the analysis. However, the Ameren order is clear that the Commission will reject attempts by parties to exclude years which are not true outliers. The Companies' witness Ms. Kallas proposes in her surreubuttal testimony that four years should be used rather than the five years used by Mr. Griffin (North Shore/Peoples Gas Ex. LMK-3.0, p. 5) without any showing on the Companies' part that 2002 is "so out of the norm as to be considered [an]'outlier[]' ". (ICC Docket Nos. 06-0070/06-0071/06-0072 Consolidated, Order Dated November 21, 2006, at 48-49).

Given the above, the Commission should adopt Staff witness Griffin's position that North Shore and Peoples Gas' Injuries and Damages expense should be $373,000 and $5,442,000 respectively.

b. Incentive Compensation Expenses

Staff contends that none of the Companies' incentive compensation costs should be reflected in rates (ICC Staff Exhibit 2.0, pp. 6 – 18 and ICC Staff Exhibit 14.0, pp. 3 – 20). Accordingly, Staff witness Pearce proposed adjustments to remove 100% of the costs of incentive compensation plans from operating expenses and rate base of North Shore and Peoples Gas (ICC Staff Exhibit 2.0, Schedules 2.2N and 2.2P, respectively). These adjustments remove costs related to the following plans: 2006 Team Incentive Award ("TIA") Plan, 2006 Individual Performance Bonus ("IPB") Plan, 2006 Short-Term Incentive Compensation ("STIC") Plan and 2006 Restricted Stock and Performance Shares Expense. These adjustments also remove costs related to the 2004 Restricted Stock and Performance Shares Incentive Compensation Plan that are included in the 2006 test year, as well as officers' bonuses and 2006 officers' incentive compensation expense charged to Peoples by an affiliate.

Staff's primary support for its adjustment is that the incentive compensation plans are discretionary in nature and there has been no showing of demonstrated ratepayer benefit. (ICC Staff Exhibit 14.0, p. 4) However, if the Commission were determined to allow some portion of these costs in rates, the least objectionable cost would be to allow costs related to that portion of the TIA Plan that is based on non-financial, i.e., operational measures that directly benefit ratepayers. In rebuttal testimony, Staff calculated an alternative of 10% cost recovery of the TIA Plan based on the number of calls to the call center component described by Mr. Hoover in his rebuttal testimony. That methodology would provide recovery in rates of $146,544 for Peoples Gas and $14,212 for North Shore Gas in 2006 test year operating expenses based on the TIA Plan expenses accrued for the test year (Id., pp. 19-20, lines 425 – 446). In response to the surrebuttal testimony of Companies' witnesses Hoover and Volante, Staff's calculated alternative to complete disallowance of all incentive compensation costs would be adjusted to $282,486 for Peoples Gas and $26,368 for North Shore (18.8% of actual payouts of $1,502,584 and $140,253 for Peoples Gas and North Shore, respectively), based on the final payout percentages and amounts awarded under the TIA Plan (North Shore/Peoples Gas Ex. JCH/FLV-2.0, lines 137 - 146). Staff's revised alternative is based on reduction of calls to the call center (the same methodology described in Staff's rebuttal testimony, as previously cited).

Mr. David J. Effron, witness for the AG, City of Chicago and CUB, also proposed adjustments to remove the costs of incentive compensation plans from the test year filings of North Shore and Peoples, however, the adjustments he reflected in his direct testimony were less than the amounts proposed by Staff witness Pearce. In his rebuttal testimony, Mr. Effron agreed with the amounts proposed by Staff witness Pearce.

Company witness Mr. James C. Hoover opposed these adjustments in rebuttal testimony (North Shore/Peoples Gas Ex. JCH-1.0) and again in surrebuttal testimony, along with Mr. Frank L. Volante (North Shore/Peoples Gas Ex. JCH/FLV-2.0). In surrebuttal testimony, Company witnesses Mr. Hoover and Mr. Volante indicated that if the Commission does not approve all of the requested recovery of incentive compensation expenses, the Commission should approve recovery of all the requested "operational" or "non-financial" expenses (North Shore/Peoples Gas Ex. JCH/FLV-2.0, lines 29 – 32) associated with the 2006 TIA Plan, which in his estimate amount to 67.2% of the actual amount paid out, or $1,009,240 and $94,204 for Peoples Gas and North Shore, respectively. In addition, Companies' witnesses request that 100% of amounts paid out under the IPB Plans be recovered, in the amounts of $625,791 and $53,107 for Peoples Gas and North Shore, respectively (North Shore/Peoples Gas Ex. JCH/FLV-2.0, lines 229 – 237).

<u>The Commission should accept Staff's adjustment.</u> As set forth in Staff witness Pearce's testimony, she disallowed the costs of incentive compensation plans for the following reasons:

1) The Plans are largely dependent upon financial goals of the Companies that benefit shareholders but not ratepayers;

2) In the future, the goals in the Plans may not be met and thus the Companies would incur no cost; and

3) Prior Commission orders support the disallowance of incentive compensation in these circumstances.

The Companies object to Staff's adjustment for two basic reasons. First, Mr. Hoover stated that the plans are "prudently and reasonably designed in order to attract and retain a sufficient, qualified, and motivated work force"; and second, he asserted that "substantial portions of the payouts under the plans are based on criteria that directly benefit customers under the standards that Staff cites" (North Shore/Peoples Gas Ex. JCH-1.0, lines 18 through 25).

Staff is not aware that the Commission has ever approved recovery of incentive compensation costs as a result of the need to 'attract and retain a sufficient, qualified, and motivated work force', as the Company now requests. Accordingly, the only legitimate criterion for recovery of any portion of incentive compensation expense, based on prior Commission practices, is the demonstration of direct ratepayer benefits. In rebuttal testimony, Company witness Mr. Hoover asserted that the TIA Plan contained "non-financial" goals that directly benefit ratepayers such that 45% of the accrued costs of that plan should be recovered from ratepayers. In surrebuttal testimony, Mr. Hoover changed his methodology to assert that the percentage should be based on the amounts actually paid out under the TIA Plan instead of amounts accrued, as reflected in the test year. He then recalculated the "non-financial" percentage of incentive compensation expense and asserted that 67.2%, not of 45% of the TIA Plan should be reflected in rates, based on actual amounts paid out for 2006 (North Shore/Peoples Gas Ex. JCH/FLV-2.0, page 7 of 11). The percentage of 67.2% includes the operational measures of (1) controlling O & M expenses (48.4%), and (2) calls to call centers (18.8%).

Staff rejects the Companies' final alternative to complete recovery of incentive compensation costs for the reasons stated at the beginning of this argument. Regarding the 25% factor for controlling O & M expenses, the Commission previously found this type of criterion to benefit shareholders rather than ratepayers, as noted in the direct testimony of Staff witness Ms. Pearce (ICC Staff Exhibit 2.0, lines 323 – 335):

> Two of the goals, earnings per share and reduced O & M expenses are goals that benefit shareholders. If the shareholders are the ones to benefit, they should be the ones who foot the bill. (Docket No. 93-0183, Order dated April 6, 1994, p. 52)

Regarding the percentage of the payout that is based on calls to the call center, Staff revised its alternative to reflect the actual payouts and percentages included in surrebuttal testimony, as previously discussed.

Regarding costs of the STIC Plan, Staff does not consider any of these accruals to be recoverable since they are based on measurements that primarily benefit shareholders, not ratepayers. For example, the awards to senior management (Chairman, President, and CEO) are entirely based on Earnings Per Share ("EPS") and normalized operating income of Peoples Energy Corporation ("PEC"). Up to 50% of the awards to the remaining participants (the Plan only applies to officers) are based on EPS. The payment trigger for all STIC is the net income of PEC. **In addition, STIC awards accrued during 2006 were not actually paid**.

Under the Individual Performance Bonus Plan, the bonus amounts are discretionary and not tied to any formula, as Mr. Hoover stated (North Shore/Peoples Gas Ex. JCH-1.0, lines 95 – 103). He rationalized that since the awards were based on an employee's individual performance, instead of the financial performance of the Companies, and because the pool from which these awards were paid was a fixed dollar amount, these awards were not tied to the financial performance of the Companies. Staff notes that these awards are **discretionary**, meaning they may be discontinued at any time after the test year. Additionally, the Companies have not demonstrated that such awards are based on specific dollar savings or other tangible benefits to ratepayers, as required by the Commission in numerous prior proceedings. Finally, the Companies indicated in response to a Staff Data Request that **the IPB Plan was only in place for 2006, the test year, not any other year in the previous five fiscal years**. This further illustrates Staff's concern that these plans are discretionary and may be changed or discontinued any time after the test year.

The Companies failed to demonstrate any ratepayer benefits or cost savings that resulted from the other Plans (officers' bonuses and incentive compensation expenses charged to Peoples Gas by an affiliate, as well as the restricted stock and performance shares programs), simply relying on the assertion that these plans are not based on "financial measures" (North Shore/Peoples Gas Ex. JCH-1.0, pp. 6 – 8, lines 114 –

146). Accordingly these plans do not meet the criteria of cost savings and/or direct ratepayer benefit that the Commission has required in numerous prior rate cases, as cited in the direct and rebuttal testimony of Staff witness Pearce. Rather these plans are based primarily on providing 'a competitive compensation package' and 'to attract and retain a qualified work force' (North Shore/Peoples Gas Ex. JCH-1.0, pp. 7-8, lines 124-153). As such, Staff contends the costs of these plans should not be reflected in utility rates.

Staff therefore maintains its position that none of the costs of incentive compensation plans should be reflected in utility rates for the reasons initially set forth in Staff witness Ms. Pearce's direct testimony and reiterated in her rebuttal testimony:

1) The Plans are largely dependent upon financial goals of the Companies that benefit shareholders but not ratepayers;

2) In the future, the goals in the Plans may not be met and thus the Companies would incur no cost (i.e., the payment of future awards is discretionary, but costs would be recovered in rates regardless); and

3) Prior Commission orders support the disallowance of incentive compensation in these circumstances (i.e., as described in items 1 and 2 absent a demonstration of direct ratepayer benefits or savings.

Finally, several of the plans at issue contain a variety of performance measurement objectives (ICC Staff Exhibit 2.0, Attachment A and ICC Staff Exhibit 14.0, Attachments A, B and C). In the future, Company management may assign different weights to these factors as they see fit. Accordingly, going forward there is no guarantee that the plans will provide any direct ratepayer benefit or savings (ICC Staff Exhibit 14.0, p. 10, lines 207-229). The degree of subjectivity and latitude allowed in making the determination of "non-financial" performance measures was demonstrated by the change in the alternative proposals contained in the Companies' rebuttal and surrebuttal positions on the incentive compensation issue. Accordingly, Staff urges the Commission to deny recovery of all incentive compensation costs in the instant proceeding.

4. Invested Capital Taxes

The Companies propose that the pro forma invested capital taxes ("ICT") in these cases is a derivative adjustment, to be calculated based on the additional operating income approved multiplied by the statutory rate of 0.8%. (Staff Cross Fiorella Exhibit 1 and 2) The Companies contend that this approach is correct since the tax, which is based upon the Companies' capital structure, was calculated based on the Company's pro forma 56/44 capital structure being maintained throughout the period of calculation. The Companies maintain that application of this capital structure to the entire year's results contains an inherent dividend policy of maintaining the pro forma capital structure at all times, and thus explicit modeling of the dividend under these conditions would lead to the same results as already provided. (Id.)

Based on this evidence, Staff's Appendices A and B to this brief, pages 9 and 8 respectively for Peoples Gas and North Shore, contain updated calculations of the pro forma ICT adjustments. Staff agrees that this is a derivative adjustment and should be updated for the Commission's final conclusions in these cases. (Tr., p. 1123)

5. Adjustment to Remove Non-Base Rate Revenues and Expenses (Schedule Presentation Issue)

Staff witness Hathhorn proposed to remove cost of gas (Rider 2) and coal tar (Rider 11) expenses and revenues since these are not subject to the increase pending in the instant proceeding. These adjustments reclassify revenues and expenses only; they have no effect on operating income. (Staff Exhibit 1, p. 8, Schedules 1.7 P and N) The Companies did not address these adjustments in testimony.

D. Derivative Adjustments from Uncontested and Contested Issues

IV. RATE OF RETURN

A. Capital Structure (Uncontested)

In the direct testimony of Bradley A. Johnson, North Shore and Peoples Gas each propose imputed capital structures comprised of 44% long-term debt and 56% common equity. (North Shore Ex. BAJ-1.1, Schedule D-1; Peoples Gas Ex. BAJ-1.1, Schedule D-1) On September 30, 2006, the actual capital structure of North Shore was comprised of 40% long-term debt and 60% common equity and the actual capital structure of Peoples Gas was comprised of 43% long-term debt and 57% common equity. (North Shore and Peoples Gas Ex. BAJ-1.1)

Staff witness Janis Freetly recommends that the Commission accept the Companies' proposed capital structures. (ICC Staff Exhibit 5.0, pp. 8-13) To evaluate the Companies' capital structures, Ms. Freetly compared the proposed capital structure to Standard & Poor's ("S&P") benchmark total debt to total capital ratio, which is published by business profile score and credit rating. S&P currently assigns North

Shore and Peoples Gas issuer credit ratings of A- and business profile scores of 3. According to S&P, the benchmark range for the total debt to total capital ratio for utilities with a business profile score of 3 is 50% to 55% for A-rated utilities and 42% to 50% for AA-rated utilities. The 44% total debt to total capital ratio proposed by both North Shore and Peoples Gas lies within the range for AA-rated utilities. According to S&P, an obligor rated AA has a very strong capacity to meets its financial commitments. Ms. Freetly also considered Ms. Kight-Garlisch's analysis of the effect of Staff's proposed revenue requirement on the other two S&P benchmark ratios, funds from operations interest coverage and funds from operations as a percentage of average debt. Ms. Kight-Garlisch concluded that under Staff's proposed revenue requirement, the financial strength is commensurate with an AA rating for North Shore and an AA- rating for Peoples Gas. (ICC Staff Exhibit 6.0, pp. 17-22) The above suggests that the Companies capital structures are commensurate with a strong degree of financial strength.

Determining the optimal capital structure is problematic; hence, an unequivocal statement of the reasonableness of a capital structure is not always possible. Nevertheless, the Commission must decide whether a capital structure is reasonable for setting utility rates. The Companies' ultimate parent company, Integrys Energy Group, Inc. ("Integrys"), has a target common equity ratio of 50-55% despite having greater operating risk than the Companies.[4] This suggests that a capital structure comprising 56% common equity may be unnecessarily expensive for the Companies. Nevertheless, Ms. Freetly recommends that the Commission accept the Companies'

[4] Integrys' S&P business profile is 5.

proposed capital structures for the following reasons. First, the September 30, 2006 measurement date for the Companies' capital structures precedes the completion of the merger with WPS Resources and the creation of Integrys. Consequently, the Companies' actual capital structures could not reflect Integrys' consolidated target common equity ratio. Second, capital structures cannot be restructured overnight. Therefore, Staff regards the Companies' voluntary decision to propose capital structures containing lower proportions of common equity than their actual capital structures as a positive first step by the Companies' new management and consider it fair to give the Companies time to make their capital structures consistent with Integrys' target consolidated capital structure.[5] Third, Staff is recommending adjustments to the costs of debt and common equity to reflect the lower risk implied by the AA rating. Should the Commission decide to impute a capital structure with a lower percentage of common equity than Staff is recommending for this proceeding, those adjustments to the costs of common equity and debt Ms. Kight-Garlsich and Ms. Freetly recommend would need to be revised to incorporate the financial strength inherent in that capital structure. (ICC Staff Exhibit 5.0, pp. 11-13) Staff witness Freetly also testified that "[u]nder no circumstances should the Commission accept the Companies' proposed capital structures without also accepting Staff's proposed adjustments to the Companies' costs of common equity and debt. A reasonable balance of financial strength and cost can only be achieved when the capital structure and the costs of the components of the

[5] Although Staff is recommending in this consolidated matter that the Commission accept the Companies' proposed capital structures, in future rate cases, should the Companies' capital structures not be consistent with that of Integrys as a whole, taking differences in operating risk into account, then Staff might recommend those capital structures be rejected.

capital structure reflect the same degree of risk. Given that the Companies' capital structure is consistent with the risk of an AA rating, the component costs of capital must reflect the risk of an AA rating". (*Id.*)

Christopher C. Thomas testified in this proceeding on behalf of CUB and the City of Chicago. He uses the capital structures proposed by the Companies in estimating the overall rates of return for North Shore and Peoples Gas. (CUB-City Exhibit 1.0, p. 3)

For the purposes of setting rates in this proceeding, the Commission should accept the Companies' proposed capital structures comprised of 44% long-term debt and 56% common equity for both North Shore and Peoples Gas.

B. Cost of Long-Term Debt (Uncontested)

1. Peoples Gas

In his direct testimony, Company witness Bradley A. Johnson stated that the actual embedded cost of long-term debt for test year ended September 30, 2006 is 4.68% for Peoples Gas. (Peoples Gas Ex. BAJ-1.0 REV, p. 10; Peoples Gas Ex. BAJ-1.2, Schedule D-3)

Staff witness Janis Freetly testified that the cost of long-term debt presented by the Companies does not reflect the stand-alone financial strength of the utilities. (ICC Staff Exhibit 5.0, p. 4) The cost of long-term debt presented by the Companies reflects the current A- S&P credit rating for the Companies. S&P downgraded the credit ratings of Peoples Gas and North Shore to A- from AA- on September 26, 2002. Staff witness Sheena Kight-Garlisch testified that affiliation with unregulated or non-utility companies adversely affected the Companies' credit ratings. (ICC Staff Exhibit 6.0, pp. 21-22) In determining a reasonable rate of return for establishing rates, Section 9-230 of the Public Utilities Act prohibits the inclusion of any incremental risk or increased cost of capital, which is the direct or indirect result of the public utility's affiliation with unregulated or nonutility companies. (Illinois Bell Telephone Co. v. Illinois Commerce Commission, 283 Ill. App. 3d 188, 210 (1996) Since most of the outstanding debt series of Peoples Gas were issued after this downgrade occurred and the downgrade was due to the utility's affiliation with unregulated companies, the costs associated with such issues need to be adjusted to eliminate the increased cost associated with the lower rating.

Peoples Gas issued the Series MM-2 bonds on February 27, 2003 and the Series NN-2 bonds on April 29, 2003. Since both of the series were issued after the utility was downgraded to A-, the interest rates must be adjusted to reflect the lower risk of the utility on a stand-alone basis. Therefore, Ms. Freetly adjusted the interest rate to reflect the spread between bonds rated Aa and A to represent the lower interest rate that would have been obtained for the bonds had the downgrade not occurred. For the Series MM-2 bonds, Ms. Freetly used the long-term utility bond yield averages for February 2003 when Aa rated utility bond yields were 6.66% and A rated utility bond yields were 6.93%, resulting in a 0.27% spread. Since the utility bond yields were for bonds with longer terms to maturity than the seven-year Series MM-2 bonds and credit spreads tend to increase as term to maturity increases, she subtracted half of the spread (0.27%/2 = 0.135%) to adjust the interest rate on the Series N-2 bonds. This adjustment lowered the interest rate on the Series MM-2 bonds to 3.87% from 4.00%. (ICC Staff Exhibit 5.0, p. 6 and Schedule 5.2P)

In April 2003, long-term utility bond yields averaged 6.47% for Aa rated bonds and 6.64% for A rated bonds, resulting in a 0.17% spread. Since credit spread is usually a direct function of term to maturity (i.e., as term to maturity increases, credit spread tends to increase as well), Ms. Freetly halved the 0.17% credit spread on long-term bond yields to 0.085% to adjust the interest rate on the ten-year Series NN-2 bonds. This adjustment lowered the interest rate of the Series NN-2 bonds to 4.54% from 4.625%. (ICC Staff Exhibit 5.0, p. 6 and Schedule 5.2P)

The Series KK, LL, OO, PP, QQ and RR bonds of Peoples Gas were issued as insured tax-exempt bonds to the Illinois Development Finance Authority ("IDFA"). The repayment of the principal and interest on the bonds issued to the IDFA is secured by an insurance policy, purchased by Peoples Gas. As a consequence of that insurance, the IDFA bonds are rated AAA. All six bond series were issued after the rating downgrade and therefore reflect the increased risk of the unregulated affiliates. Had Peoples Gas' credit ratings not been downgraded, the insurance premium would have been lower since Peoples Gas would have posed less credit risk to the insurers of the bonds. Therefore, Ms. Freetly reduced the recoverable insurance fees for each of the issues and the associated annual amortization of those fees to reflect the lower credit risk had Peoples Gas' rating remained AA-. She began with the total amount of the insurance fee paid by Peoples Gas on each tax-exempt series and subtracted amortization through September 30, 2006. Then, she reduced the September 30, 2006 unamortized debt expense balance by half, which thereby reduced the amortization of debt expense by the amount attributed to that portion of the insurance fee. This adjustment reduced the embedded cost of debt for Peoples Gas. (ICC Staff Exhibit 5.0, pp. 6-8 and Schedule 5.2P)

The interest rates on the Series OO and PP bonds are adjustable based on an auction rate. The interest rates presented on Schedule D-3 by Peoples Gas for the Series OO and PP are based on the auction rate in effect at September 30, 2006. Ms. Freetly updated those interest rates to reflect the auction rate that would have been in effect on the stock price measurement date (April 25, 2007) used by Staff witness Sheena Kight-Garlisch in her cost of equity analysis. For the Series OO bonds, she used the 3.70% auction rate that was set at the April 25, 2007 auction. For the Series PP bonds, she used the 3.66% auction rate that was set at the March 28, 2007 auction. (ICC Staff Exhibit 5.0, p. 8)

In the Rebuttal testimony of Bradley Johnson, the Companies agreed that it is reasonable to adjust the cost of long-term debt to reflect their stand-along financial strength to the extent that it differs from the financial strength of Integrys Energy Group, Inc. Peoples Gas and North Shore further agree that although the adjustments are small in this case, it is important to reflect the Companies stand-alone financial strength in their rates. However, the Companies believe that Staff's adjustments to the costs of long-term debt are excessive, and propose taking only half of the adjustment that Staff proposed in direct testimony. (North Shore/Peoples Gas Ex. BAJ-2.0) At the time the bonds were issued, the Companies had a split rating from the credit rating agencies. Staff's proposed adjustment to the cost of debt was based on the spread between long-term utility bonds rated Aa and those rated A to reflect the S&P credit rating downgrade in September 2002. Moody's Investors Service also downgraded the Companies in

September 2002 from Aa2 to Aa3. Hence, at the time the long-term debt was issued by the Companies, Peoples Gas and North Shore were rated A- from S&P and Aa3 by Moody's. The Companies proposed to reflect the split rating by taking only half of Ms. Freetly adjustment to the costs of long-term debt. ((North Shore/Peoples Gas Ex. BAJ-2.0, p. 4)

Ms. Freetly agreed that the split rating should be reflected in the adjustments to the costs of long-term debt to reflect the stand-alone financial strength of the Companies in her rebuttal testimony. However, she testified that the approach taken by the Companies assumes that no downgrade from Moody's occurred and therefore does not technically comport with the requirements to Section 9-230 of the Act. Although the Companies remained in the Aa range following the downgrade by Moody's, even the effect on the cost of debt of a one notch credit rating downgrade needs to be examined to ensure that not one iota of incremental risk is included in the cost of capital for setting rates in this proceeding. (Illinois Bell Telephone Co. vs. Illinois Commerce Commission, 283 Ill App 3d 188, 207(1996)) (ICC Staff Exhibit 17.0, pp. 2-4)

To determine the effect of the Moody's downgrade on the Companies' cost of debt, Ms. Freetly reduced her original adjustment to reflect the average of the two credit rating downgrades. In September 2002, the downgrade from S&P was three notches, from AA- to A-, while the downgrade from Moody's was one notch, from Aa2 to Aa3. Hence, on average the credit rating was downgraded two notches. (ICC Staff Exhibit 17.0 at 4-5) The spread between yields on bonds in the Aa and A ranges is equivalent to a three notch difference since it most closely reflects the midpoint of the ranges, or the spread between Aa2 and A2. Therefore, Ms. Freetly took two-thirds of her original adjustment to reflect the average downgrade of two notches. Specifically, she reduced her original adjustment of the interest rates on the Series MM-2 and NN-2 for Peoples Gas, as well as the adjustment to the insurance premiums on the tax exempt bond series of Peoples Gas (Series KK, LL, OO, PP, QQ and RR), to reflect only two-thirds of the spread between utility bonds rated Aa and A that Staff witness Freetly used in direct testimony. (ICC Staff Exhibit 17.0, pp. 4-5)

Ms. Freetly's approach using two-thirds of the Aa-A debt yield spread better comports to the requirements of Section 9-230 of the Act since both of the downgrades are factored in. However, the Companies' approach to use one-half of the original adjustment results in the same weighted cost of debt of 2.05% for Peoples Gas, the adjustments proposed by the Companies are sufficient to remove the incremental cost of capital associated with the credit ratings downgrade due to the Companies' affiliation with nonregulated companies. Although Staff does not agree with the Companies' approach, Staff will not contest the Companies' proposed adjustments in this proceeding since they result in the same weighted cost of debt as Staff's proposed adjustment reflecting the split credit rating.

Staff accepts the resulting interest rate of 3.93% for the Series MM-2 bonds and 4.58% for the Series NN-2 bonds. These interest rate adjustments, along with the adjustments to the insurance premiums on the tax exempt bonds, result in an embedded cost of long-term debt for September 30, 2006 equal to 4.67% for Peoples Gas. (ICC Staff Exhibit 17.0, Schedule 17.2P)

2. North Shore

In his direct testimony, Company witness Bradley A. Johnson stated that the actual embedded cost of long-term debt for test year ended September 30, 2006 is 5.42% for North Shore. (North Shore Ex. BAJ-1.0; p. 9; North Shore Ex. BAJ-1.2, Schedule D-3)

Staff witness Janis Freetly testified that the cost of long-term debt presented by North Shore does not reflect the stand-alone financial strength of the utility. Since one of the outstanding debt series of North Shore was issued after the Companies were downgraded by S&P and the downgrade was due to the utility's affiliation with unregulated companies, the cost associated with that issue needs to be adjusted to eliminate the increased cost associated with the lower rating. (ICC Staff Exhibit 5.0, p. 4)

North Shore issued the Series N-2 bonds on April 29, 2003, after the utility was downgraded by S&P to A-. Therefore, Ms. Freetly adjusted the interest rate to reflect the spread between bonds rated Aa and A to represent the lower interest rate that would have been obtained for the Series N-2 bonds had the downgrade not occurred. In April 2003, long-term utility bond yields averaged 6.47% for Aa rated bonds and 6.64% for A rated bonds, resulting in a 0.17% spread. Since credit spread is usually a direct function of term to maturity (i.e., as term to maturity increases, credit spread tends to increase as well), Ms. Freetly halved the 0.17% credit spread on long-term bond yields to 0.085% to adjust the interest rate on the ten-year Series N-2 bonds. This adjustment lowered the interest rate on the Series N-2 bonds to 4.54% from 4.625%.[6] (ICC Staff Exhibit 5.0, p. 5 and Schedule 5.2N)

In the Rebuttal testimony of Bradley Johnson, the Companies agreed that it is reasonable to adjust the cost of long-term debt to reflect their stand-alone financial strength. The Companies proposed to reflect the split rating by taking only half of Ms. Freetly adjustment to the costs of long-term debt. (North Shore/Peoples Gas Ex. BAJ-2.0, p. 4)

Ms. Freetly agreed that the split rating should be reflected in the adjustment to the cost of long-term debt to reflect the stand-alone financial strength of the Companies in her rebuttal testimony. Ms. Freetly took two-thirds of her original adjustment to reflect the average downgrade of two notches. Specifically, she reduced her original adjustment of the interest rate on the Series N-2 bonds for North Shore to reflect only two-thirds of the spread between utility bonds rated Aa and A that she used in her direct testimony. Since there was no difference in the weighted cost of debt when taking two-thirds or one-half of Staff's original adjustment to North Shore's Series N-2 bonds, Staff will accept the Company's adjustment, which results in an interest rate of 4.58% for North Shore's Series N-2 bonds. The resulting embedded cost of long-term debt for September 30, 2006 equals 5.39% for North Shore. (ICC Staff Exhibit 17.0, pp. 5-6 and Schedule 17.2N)

[6] Although the adjustment to the cost of the Series N-2 bonds is small, Staff understands that the Commission is obligated to remove the entire increase to a utility's cost of capital resulting from its affiliation with unregulated and non-utility companies, regardless of the magnitude of that increase.

C. Cost of Common Equity

The difference between, the results of Companies' witness Mr. Moul's CAPM and DCF analyses, excluding adjustments, and Staff's is only 11 basis points. The major differences between the Companies' and Staff's cost of common equity recommendations are in the adjustments to the Utility Sample's cost of common equity. Mr. Moul testified that he adjusted his results because the market-value based common equity ratios of his sample are higher than the book-value based equity ratios for the Companies. He also made an adjustment for flotation costs. Ms. Kight-Garlisch adjusted her Utility Sample cost of common equity to reflect the lower financial risk of the Companies compared to the Utility Sample.

1. Peoples Gas

a. Staff's Analysis of Cost of Equity

Staff witness Sheena Kight-Garlisch estimated the investor-required rate of return on common equity to be 9.70% for Peoples Gas. (ICC Staff Exhibit 6.0, p. 2) Ms. Kight-Garlisch measured the investor-required rate of return on common equity with the discounted cash flow ("DCF") and Capital Asset Pricing Model ("CAPM") analyses. She applied those models to a sample of gas utility companies ("Utility Sample") that Peoples Gas' witness Moul used in his estimate of a fair return on common equity. Ms. Kight-Garlisch believed that Mr. Moul's sample companies are reasonable operating risk proxies for Peoples Gas. (*Id.*, p. 2)

The sample group has at least 70% of its assets dedicated to gas operations. In addition, the average business profile of the sample group is 3, which is identical to the business profile of Peoples Gas. The percentage of gas assets and business profiles are operating risk measures. (*Id.*, pp. 2-3)

(1) DCF Analysis

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments to the holders of that stock. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that a stock price embodies. The companies in Ms. Kight-Garlisch's Utility Sample pay dividends quarterly. Therefore, Ms. Kight-Garlisch applied a constant-growth quarterly DCF model. (*Id.*, p. 4)

DCF methodology requires a growth rate that reflects the expectations of investors. Staff witness Kight-Garlisch measured the market-consensus expected growth rates with projections published by Zacks, Yahoo, and Reuters. The growth rate estimates were combined with the closing stock prices and dividend data as of April 25, 2007. Based on this growth, stock price, and dividend data, Ms. Kight-Garlisch's DCF estimate of the cost of common equity was 8.23% for the Utility Sample. (*Id.*, pp. 5-7)

(2) Risk Premium Analysis

According to financial theory, the required rate of return for a given security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. Staff witness Kight-Garlisch used a one-factor risk premium model, the Capital Asset Pricing Model ("CAPM"), to estimate the cost of common equity. In the

CAPM, the risk factor is market risk, which cannot be eliminated through portfolio diversification. (*Id.*, pp. 7-8)

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Ms. Kight-Garlisch combined betas from Value Line and a regression analysis. The average Value Line beta estimate was 0.87, while the regression beta estimate was 0.62. (*Id.*, pp. 12-15) For the risk-free rate parameter, Ms. Kight-Garlisch considered the 4.83% yield on four-week U.S. Treasury bills and thirty-year U.S. Treasury bonds. Both estimates were measured as of April 25, 2007. Since the yields on the two Treasury securities are identical, her estimate of the risk-free rate equaled 4.83%. (*Id.*, pp. 10-11) Finally, for the expected rate of return on the market parameter, Ms. Kight-Garlisch conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market was 13.46% for the first quarter of 2007. (*Id.*, p. 12) Inputting those three parameters into the CAPM, Ms. Kight-Garlisch calculated a cost of common equity estimate of 11.34% for the Utility Sample. (*Id.*, p. 15)

(3) Recommendation

Based on her DCF and risk premium analyses, Staff witness Kight-Garlisch estimated that the cost of common equity for the Utility Sample is 9.79%. (*Id.*, p. 16) To determine the suitability of that cost of equity estimate for North Shore and Peoples Gas, Ms. Kight-Garlisch assessed the risk level of her Utility Sample relative to that of Peoples Gas. The S&P credit rating and business profile score for the Utility Sample averaged A and 3[7], respectively. (*Id.*, p. 3 and p. 21) To estimate the risk of Peoples Gas going forward, Ms. Kight-Garlisch compared the financial strength implicit in the revenue requirement Staff recommends for the Company to utility benchmarks. (*Id.*, p. 17)

S&P categorizes debt securities on the basis of the risk that a company will default on its interest and principal payment obligations. The resulting credit rating reflects both the operating and financial risks of a utility. Although no formula exists for determining a credit rating, S&P publishes utility benchmark values, by business profile score, for the financial ratios it uses to determine credit ratings. Therefore, Ms. Kight-Garlisch compared the values for the benchmark financial ratios that result from Staff's proposed revenue requirement to S&P's benchmarks for utilities with a business profile score of 3. The benchmark financial ratios which Ms. Kight-Garlisch compared were (1) the funds from operations ("FFO") interest coverage ratio and (2) FFO to total debt ratio. The FFO interest coverage ratio and FFO to total debt ratio benchmark values for utilities with a business profile score of 3 as well as those same ratios resulting from Staff's proposed revenue requirement are presented below in Table 1 – Benchmark Ratios. (*Id.*, p. 17-19)

Table 1 – Benchmark Ratios

	AA	A	BBB
Financial Guideline Ratios			

[7] The business profile score of 3 is identical to the business profile score of both North Shore and Peoples Gas (ICC Staff Exhibit 6.0, p. 3)

	AA	A	BBB
FFO/IC	3.5-4.5X	2.5-3.5X	1.5-2.5X
FFO/Debt	25-30%	15-25%	10-15%
Total Debt/Total Capital	42-50%	50-55%	55-65%
Staff Proposal – Peoples Gas			
FFOIC	4.8X		
FFO/Debt		17.4%	
Total Debt/Total Capital	44%		

Peoples Gas' financial ratios indicate a level of financial strength commensurate with an AA- credit rating. (*Id.*, p. 18) Peoples Gas' financial strength is greater than that implied in the Utility Sample's A average credit rating, which in turn indicates that Peoples Gas has less financial risk and thus less total risk than the Utility Sample.[8] Since investors require lower returns to accept lower exposure to risk, Ms. Kight-Garlisch concluded that a downward adjustment to the cost of common equity of her Utility Sample is required given the difference between the implied forward-looking credit ratings for Peoples Gas, which was an AA- and the A average credit rating for the Utility Sample. (*Id.*, p. 19) Thus, Ms. Kight-Garlisch adjusted the 9.79% Utility Sample's investor-required rate of return downward to 9.70% for the 9 basis point spread between A rated and AA- rated 30-year utility debt yields for Peoples Gas. (*Id.*, p. 21)

While Standard and Poor's currently rates Peoples Gas A-, it is appropriate to adjust the cost of common equity recommendation for Peoples Gas to reflect a credit

[8] While Peoples Gas and the Utility Sample have a similar level of operating risk, Peoples Gas has less financial risk. Thus in terms of total risk (i.e., operating + financial risk), Peoples Gas is less risky than the Utility Sample (ICC Staff Ex. 6.0, pp. 17-18).

rating of AA- not only because the benchmark financial ratios that result from Staff's proposed revenue requirements are those of a company with an AA- credit rating but also because Peoples Gas' affiliation with unregulated or non-utility companies lowered its credit ratings. On September 26, 2002, Standard and Poor's downgraded Peoples Gas to A- from AA-. The downgrade was a result of the Peoples Gas' parent company, Peoples Energy Corporation's ("Peoples Energy") "increasing business risk with the growing share of nonregulated business." In addition, the financial ratios for Peoples Gas were improving during the period leading up to S&P's downgrade of its credit ratings. The benchmark ratios for Peoples Gas from 2001-2003 are presented below in Table 2. (*Id.*, pp. 21-22)

Table 2

	2001	2002	2003
<u>Peoples Gas</u>			
FFOIC	3.5X	7.1X	7.3X
FFO/Debt	16.2%	25.5%	26.1%

Section 9-230 of the Illinois Public Utilities Act ("Act")(220 ILCS 5/9-230 *et seq*.), which applies "in any proceeding to establish rates or charges …" (220 ILCS 5/9-230), prohibits the Commission from including the incremental risk or increased cost of capital resulting from a utility's affiliation with unregulated or non-utility companies. (<u>Illinois Bell Telephone Co. v. Illinois Commerce Commission</u>, 283 Ill. App. 3d 188, 210 (1996)). Since Peoples Gas' A- credit rating is a function of its affiliation with unregulated or non-utility companies, the cost associated with that credit rating cannot be reflected in Peoples Gas' rates. In contrast, unregulated or non-utility affiliations do not affect the credit ratings implied by Peoples Gas' forward-looking financial ratios, which are calculated wholly from its revenue requirement. (*Id.*, p. 22) Ms. Kight-Garlisch's downward adjustment to the cost of common equity of her Utility Sample addresses the requirements of Section 9-230.

Finally, Ms. Kight-Garlisch notes that a downward adjustment to her cost of equity recommendation would be necessary if the Commission approved any of Peoples Gas' proposed riders. (*Id.*, p. 23) Ms. Kight-Garlisch did not agree with Mr. Moul's assumption that without the riders, Peoples Gas is riskier than the Utility sample. (*Id*.,) Ms. Kight-Garlisch testified that Commission approval of a rider would reduce the operating risk of Peoples Gas. Since Ms. Kight-Garlisch's cost of equity recommendation is based upon Peoples Gas' current business profile, which does not reflect the reduction in operating risk that would result from adoption of a rider, she explained that her cost of equity recommendation for Peoples Gas would need to be adjusted downward. (*Id*.) Ms. Kight-Garlisch provided the Commission with guiding principles in her direct testimony in the event the Commission approved any of the riders. (*Id*., pp. 23-24)

b. Summary of Parties Analysis of Cost of Common Equity

(1) Peoples Gas' Analysis

Peoples Gas witness Paul R. Moul recommended an 11.06% rate of return on common equity. Mr. Moul utilized both the DCF and risk premium analyses. He applied the DCF analyses to a sample of 9 gas companies ("Gas Group"). (Peoples Gas Ex. PRM-1.0, pp. 7-11)

For the DCF, he utilized three quarterly models. (*Id*., p. 16) For the equity risk premium test, Mr. Moul used the CAPM and bond yield plus risk premium models based on historic achieved equity risk premiums. (*Id*., pp. 31 and 36) He also used the comparable earnings analysis as a test of the reasonableness of the DCF and equity risk premium results.

Mr. Moul proposed two adjustments to the cost of equity estimates: a flotation cost adjustment and another adjustment to account for the difference between market and book value of equity. (*Id*., pp. 27-30 and 36-41) The cost of equity determined from Mr. Moul's DCF analysis, before leverage and flotation cost adjustments, would be 9.01%. The cost of equity estimate derived from his CAPM analysis, disregarding leverage and flotation cost adjustments, would be 10.79%. The resulting cost of equity averages 9.90%. (ICC Staff Exhibit 6.0, pp. 37-38)

(2) CUB-City's Analysis

CUB-City witness Christopher C. Thomas recommended an 8.11% cost of common equity. (CUB-City Exhibit 1.0, p. 2) Mr. Thomas derived his estimate using the annual DCF model. He applied that model to Mr. Moul's Gas Group. (*Id*., pp. 9 and 12) Mr. Thomas also performed an analysis using the CAPM model to check the results of his DCF analysis . (*Id*., p. 9)

c. Cost of Equity Issues

Throughout the proceeding the arguments presented by the parties on the cost of equity related primarily to three issues: (a) risk adjustment, (b) market to book adjustments, and (c) reliance on the CAPM. In addition, Mr. Moul and Mr. Thomas raised a few issues that Staff addresses separately in sections (iv) and (v) below.

(1) Risk Adjustment: Staff's Downward Adjustment to its Sample's Average Cost of Equity Reflects the Lower Risk of Peoples Gas

Peoples Gas witness Mr. Moul argued that the downward adjustment to the cost of common equity of the Utility Sample that Staff witness Kight-Garlisch made for People Gas is not justified. (North Shore/Peoples Gas Exhibit 2.0, pp. 20-22) Mr. Moul is wrong; financial theory rests upon the foundation that investors require higher returns to accept greater exposure to risk. Conversely, the investor required rate of return is lower for investments with less exposure to risk. (Kight-Garlisch, ICC Staff Exhibit 6.0, p.19)

In response to Staff's use of S&P credit ratings, Peoples Gas witness Moul testified that it is not appropriate to use S&P's published financial ratio guidelines as the basis for the reasonableness of a recommendation for a given cost of equity. (North Shore/Peoples Gas PRM Exhibit 2.0, pp. 21-22) Mr. Moul's argument should be rejected. S&P uses the benchmark ratios as part of its evaluation of the credit quality of utilities. Although credit ratio analysis is an important part of S&P's rating process, these benchmark ratios are not the only critical financial measures that S&P uses in its analytical process. S&P also analyzes a wide array of financial ratios that do not have published guidelines. Consequently, Ms. Kight-Garlisch did not use the benchmark ratios to predict credit ratings. Rather, she used the benchmark ratios as a measure of the financial strength Peoples Gas could possibly attain given its level of business risk and the impact of Staff's proposed revenue requirement and capital components and costs in this proceeding. Mr. Moul's argument against the use of credit ratings in evaluating the reasonableness of a cost of equity estimate is inconsistent with his own use of credit ratings and leverage ratios to evaluate a sample used to estimate cost of common equity. (See North Shore Ex. PRM-1.0 Rev, p. 9, lines 182-200; Id. p. 11, lines 224 -235; Id., p. 12, lines 251-258 and Peoples Gas Ex. PRM-1.0 Rev, p. 9, lines 193-203; Id., p. 11, lines 228-240; Id., p. 12, lines 256-264) The Commission should not ignore the level of financial strength implied by the benchmark ratios in comparing the riskiness of Peoples Gas versus the proxy sample. The FFO interest coverage ratio and FFO to total debt ratio for Peoples Gas indicates that Staff's proposed rates are sufficient to support financial strength that is commensurate with a credit rating of AA-. Since this implied forward-looking credit rating is higher than the average A credit rating of Ms. Kight-Garlisch's sample, a downward adjustment is necessary to reflect the basic tenet of financial theory -- the investor-required rate of return is lower for investments with less exposure to risk. (ICC Staff Exhibit 6.0, pp. 17-22)

(2) Market to Book: The Market to Book Adjustments Proposed by Peoples Gas is Inappropriate

Peoples Gas' incorrectly proposed adjustments to the cost of equity to account for the difference between the market value and the book value of Peoples Gas' common equity. Its proposed adjustments should be rejected. Peoples Gas' argument is based on a flawed premise.

Mr. Moul's adjustment of his market-based DCF and CAPM models for application to book value has both theoretical and empirical flaws. Financial theory provides no basis for Mr. Moul's modification of the DCF and CAPM models. In addition, Mr. Moul's adjustments to his DCF and CAPM models are based on the incorrect notion that utilities should be authorized rates of return on common equity in excess of the investor-required return whenever their market values of common equity exceed book values. To address this issue, one must first explore why the market value of utility common equity exceeds book value, which Mr. Moul has failed to do. (ICC Staff Exhibit 6.0. p. 33)

There are two possible explanations for how utility stock prices have come to exceed their respective book values: (1) the investor-required rate of return has fallen or (2) expectations of future earnings have risen. The investor-required rate of return on an investment in a utility would fall if either the price of risk (i.e., the risk premium) has fallen or if investors' perceived level of risk in that utility has fallen. Either way, if a utility's stock price grows to exceed its book value due to a decline in investors' required rate of return for that utility, then it obviously follows that the Commission should authorize a lower rate of return. (*Id*., p. 33)

An increase in investors' expectations of future returns could also cause a rise in market values over book values. Such an increase in expectations may be due to positive deviations from the test year amounts upon which the company's rates are set. Clearly, the Commission should not approve higher rates today based on such deviations (e.g., higher than projected sales) from past rate case estimates. Increased expectations of future returns may also be a function of earned returns from sources other than the revenue requirements formula component (R_{Other}), the product of rate base and rate of return. Earnings from these sources could allow a utility to earn returns beyond the level needed to meet investors' required rate of return. (*Id*., p. 34)

R_{Other} can come from a number of sources. First, many utilities have unregulated sources of income that would contribute to earnings beyond the level needed to meet the required rate of return. Obviously, the Commission should not allow utilities higher rates of return due to stock price increases caused by such unregulated operations.

Second, the normalization of deferred income taxes and income tax credits might also contribute to the divergence between utility market and book common equity values since that practice compensates utilities for taxes they do not yet owe. Finally, investors do not value utilities on the basis of accounting earnings, as Mr. Moul suggests, but on economic earnings and cash flow. In utility revenue requirements, part of cash flow comes from operating income (i.e., rate base $\times$ rate of return). The larger share of the remainder comes from operating expenses in the form of depreciation and deferred taxes. The Commission should not further increase allowed rates of return when benefits that utilities receive from other aspects of the rate setting process such as tax normalization rules and cash flow from sources such as depreciation and deferred taxes increase stock prices above book value. To do otherwise would compensate utilities twice for the same sources of cash flow. (*Id*., pp. 34-35)

Mr. Moul presented an example which implied that the required return on book value is 50% higher than the required return on market value when the market to book value ratio is 150%. However, Mr. Moul wrongly assumed that the product of rate base times rate of return is the only source of earnings for a utility. As discussed above, there are a number of ways in which a utility can earn returns above and beyond the product of rate base times rate of return. Mr. Moul did not demonstrate that utilities earn no returns beyond the product of rate base times rate of return. To the contrary, the fact that the market value of utilities' common stock exceeds book value indicates that utilities do, in fact, earn returns from other sources in addition to the product of rate base times rate of return. (*Id*., p. 35)

The danger in allowing a utility to earn a rate of return on rate base equal to the product of its market-to-book ratio and the market required rate of return on common equity becomes apparent when those other sources (R_{Other}) of value are recognized. Consider Mr. Moul's example. In that example, the investor-required rate of return (k_M) was assumed to be 12.5%, the book value of common equity (B) was assumed to be \$8, and the market value of common equity (M) was assumed to be \$12. Mr. Moul implies that that would necessitate an 18.75% allowed return on rate base (k_A) to achieve an expected \$1.50 per share. If the utility is authorized the investor-required rate of return of 12.5% on \$8 per share rate base, then investors should expect \$1 per share in earnings from the operating income component of its revenue requirement. Consequently, if investors value such a utility at \$12 per share rather than \$8 per share, then investors must expect an additional \$0.50 per share from another source (R_{Other}). If that utility were then allowed to earn a return on rate base of 18.75% rather than the investor-required rate of return of 12.5%, such that $k_A \times B = k_M \times M =$ \$1.50 per share, then the additional \$0.50 per share investors expect to receive from R_{Other} would boost total returns per share to \$2.00. As a result, investors would realize \$0.50 in returns in <u>excess</u> of expectations. Those excess returns would cause the market value of common equity to rise to a market price of \$16.00 (i.e., \$2.00 ÷ 12.5%) from the initial market price of \$12.00 to reach the required rate of return of 12.5%. Consequently, the utility's market-to-book ratio would increase from 150% (i.e., \$12.00 ÷ \$8.00) to 200% (i.e., \$16.00 ÷ \$8.00). According to Mr. Moul's logic, that increase in stock price should lead to an additional increase in the allowed rate of return to 25.0% since the \$8.00 in book value common equity would now have to produce \$2.00 per share (i.e., $k_M \times M =$

12.5% $\times$ \$16.00). The result is a never ending upward spiral as each successive increase in market value would lead to another increase in the allowed rate of return, which in turn, would lead to a further increase in market value. (*Id*., pp. 35-36)

Mr. Moul argued that the divergence of price and book value also creates a financial risk difference. Mr. Moul's argument lacks merit, since, the intrinsic financial risk of a given company does not change simply because the manner in which it is measured has changed. Such an assertion is akin to claiming that the ambient temperature changes when the measurement scale is switched from Fahrenheit to Celsius. Specifically, capital structure ratios are merely indicators of financial risk; they are not sources of financial risk. Financial risk arises from contractually required debt service payments. Changing capital structure ratios from a market to book value basis does not affect a company's debt service requirements. (*Id*., p. 37)

Thus, Peoples Gas' cost of common equity does not need to be adjusted to account for the difference between the market value and the book value of its common equity. The Commission has rejected use of the leverage adjustments in Docket Nos. 01-0528/01-0628/01-0629 Consol., 99-0120/99-0134 Consol. and 94-0065. (*Id*., p. 37) The Commission should again reject Mr. Moul's market to book adjustments. As with previous arguments that have been rejected by the Commission in past cases, the market to book adjustment is based on the false argument that an adjustment to a cost of equity estimated derived from a market value of equity is necessary when that estimate is to be applied to book value of equity to determine utility rates.

(3) CAPM Analysis

CUB-City witness Mr. Thomas argues that the CAPM is best used as a reference to check the results from the DCF analysis. However, Mr. Thomas recognizes that both the DCF and CAPM have questions about their usefulness. (Thomas Dir., CUB-City Ex. 1.0, p. 41) Mr. Thomas provides no evidence that the DCF is a superior model to the CAPM. Although both models have questions about their usefulness, when applied appropriately, they are valid and useful predictors of the investor's required rate of return. The use of more than one model improves the validity of the cost of common equity estimate. (Tr., p. 1081; Tr., p1260)

Mr. Thomas' primary concerns with the CAPM model are the beta and the equity market risk premium ("EMRP"). He erroneously attempted to correct errors in Mr. Moul's CAPM analysis by using the raw beta and using the EMRP from financial literature instead of calculating a current EMRP.

Mr. Moul and Ms. Kight-Garlisch both correctly used adjusted betas instead of raw betas. The raw (i.e., historical) betas for the companies in the sample are adjusted to improve the accuracy of the beta estimates. Ex post empirical tests of the CAPM suggest that the linear relationship between risk, as measured by raw beta, and return is flatter than the CAPM predicts. That is, securities with raw betas less than one tend to realize higher returns than the CAPM predicts. Conversely, securities with raw betas greater than one tend to realize lower returns than the CAPM predicts. Adjusting the raw beta estimate towards the market mean of 1.0 results in a linear relationship between the beta estimate and realized return that more closely conforms to the CAPM prediction. Securities with betas less than one are adjusted upwards thereby increasing the predicted required rate of return towards observed realized rates of return.

Conversely, securities with betas greater than one are adjusted downwards thereby decreasing the predicted rate of return towards observed realized rates of return. Thus, adjusted betas surpass raw betas as predictors of future returns and are, therefore, superior forward-looking betas. Consistently, Seth Armitage in his text, “The Cost of Capital,” with regard to this argument, notes that studies have shown that such adjustments result in appreciably better forecasts, finding that the reduction in both bias and inefficiency is greater the further away from one the beta in question is. (ICC Staff Exhibit 18.0, pp. 19-20) Mr. Thomas’ criticisms of beta are insufficient to warrant dismissal of the CAPM as a useful model for estimating the cost of equity.

Mr. Thomas’ second concern with the CAPM model was the EMRP input. Mr. Thomas presented academic research indicating that the proper expected common EMRP for determining the investor-required rate of return is between 3 and 5%. However, the research cited by Mr. Thomas represents various academics’ opinions of the common equity risk premium investors should expect, which is not necessarily the same as what the investors truly are expecting. Since the relationship between the returns of the stock market and U.S. Treasury bonds is not stable over time, current returns provide the best indication of what investors are expecting going forward. Hence, Ms. Kight-Garlisch’s estimate of the common equity risk premium, derived by subtracting the current yield on long-term U.S. Treasury bonds from the first quarter return on the S&P 500 provides the actual difference between returns on risk-free and risky securities that exists in today’s market. (*Id*., p. 20)

(4) Other Problems with Peoples Gas' Cost of Common Equity Analysis

Mr. Moul's cost of common equity analysis contains several errors that lead him to over-estimate Peoples Gas' cost of common equity. The most significant flaw in Mr. Moul's analysis was his market to book adjustment discussed previously. However, Mr. Moul's analysis was also flawed by his use of historical data and his common equity risk premium.

Mr. Moul's use of historical data is problematic. First, historical data favors outdated information that the market no longer considers relevant over the most-recently available information. Second, historical data reflects conditions that may not continue in the future. In other words, use of average historical data implies that securities data will revert to a mean. Even if securities data were mean reverting, there is no method for determining the true value of that mean let alone the length of time over which mean reversion will occur. Consequently, sample means, which depend upon the measurement period used, are substituted. Thus, any measurement period chosen is arbitrary, rendering the results uninformative. (ICC Staff Exhibit 6.0, p. 28)

Mr. Moul used historical data to estimate the growth rate and dividend yield in his DCF analysis, the A-rated utility bond default premium and the common equity risk premium in his RPM analysis, and the common equity risk premium in his CAPM analysis. (*Id*., pp. 28-29)

Historical data can distort cost of common equity analyses. First, consider Mr. Moul's use of historical data in determining the dividend yield (dividend ÷ stock price) in his DCF model. Since stock prices reflect all current information, only the most recent stock price can reflect the most recently available information. Historical stock prices must include observations that cannot reflect the most current information available to the market. For example, if the actual earnings for a company were much higher than anticipated, the market would react to that news and bid up its stock price. Consequently, the pre-earnings announcement stock prices would reflect obsolete information and understate the value of that company's stock. (*Id*., p. 29)

Mr. Moul implies that his use of historical data to estimate the dividend yield is an attempt to reduce measurement error when he states that "the use of this [six-month] dividend yield will reflect current capital cost rates while avoiding spot yields." However, while it is true that measurement error is a problem inherent in cost of common equity analysis and should be reduced whenever possible, introducing old stock prices into an analysis simply substitutes one alleged source of measurement error, volatile stock prices, for another, irrelevant stock prices. Stock prices can be influenced by temporary imbalances in supply and demand; however, any distortions such imbalances might have on the measured cost of common equity can be reduced through the use of samples, a technique which Mr. Moul already applies. (*Id*., pp. 29-30)

Next, consider Mr. Moul's CAPM analysis, which calls for an estimate of the investor-required rate of return on the market portfolio. Mr. Moul estimates the required rate of return on the market using, in part, historical earned rates of return. As proxies for current required rates of return, historical earned returns possess several shortcomings. First, the returns an investment generates are unlikely to have equaled investor return requirements due to unpredictable economic, industry-related, or company-specific events. Second, even if an investment's return equaled investor requirements in a given period, both the price of, and the investment's sensitivity to, each source of risk changes over time. Consequently, the past relationship between two investments, such as common equity and debt, is unlikely to remain constant. Third, the magnitude of the historical risk premium depends upon the measurement period used. Unfortunately, no proven method exists for determining the appropriate measurement period. Thus, historical earned rates of return are questionable estimates of the required rate of return that are susceptible to manipulation and whose use could distort the estimate of a company's cost of common equity. (*Id*., p. 30)

The Commission has previously rejected the use of historical data in determining a company's cost of common equity. In Docket No. 92-0357, a rate proceeding for Iowa-Illinois Gas and Electric Company, the Commission Order stated, "[t]he Commission notes that the investor-required return on common equity is a forward-looking concept. Mr. Benore [the company witness], in many instances, inappropriately utilized historical data to determine the Company's cost of common equity."[9] Similarly, in Docket No. 95-0076, a rate proceeding for Consumers Illinois Water Company, the Commission Order stated, "[t]he Commission also concludes that Staff's criticism of Dr. Phillips' use of two-month average historical stock prices and historical growth rates in his traditional DCF analysis, and historical risk premiums in his risk premium analysis are valid. Historical data is inappropriate in determining a forward-looking cost of common equity because it contains information that may no longer be relevant to investors."[10] (*Id*., p. 31)

Mr. Moul's risk premium analysis is also flawed. His methodology for determining a reasonable common equity risk premium for his proxy groups is

[9] Order, Docket No. 92-0357, July 21, 1993, p. 66.
[10] Order, Docket No. 95-0076, December 20, 1995, p. 70.

inappropriate. In determining the common equity risk premium, Mr. Moul began with a 5.20% base common equity risk premium estimate representing the historical earnings spread between public utility bonds and the S&P Utilities Index, which he adjusted to 5.00%. Unfortunately, the ultimate estimate was based on flawed methodology. First, Mr. Moul's base common equity premium estimate is calculated from historical data, which is inappropriate. As discussed previously, the magnitude of a historical risk premium depends upon the measurement period used, as evidenced by Mr. Moul's own results shown on Peoples Gas Ex. PRM-1.10, page 2. For example, had Mr. Moul used the 1952-2005 measurement period, his base common equity premium estimate would have been 6.05% rather than 5.20%. Second, Mr. Moul added a risk premium measured from a public utility bond index to an estimate of A-rated bond yield without providing any support that the two are equivalent. Third, Mr. Moul provides no quantitative support for the adjustments he made in deriving estimates of the common equity risk premium from the base common equity risk premium. (*Id*., pp. 31-32)

(5) Other Problems with CUB-City's Cost of Common Equity Analysis

There are a few other items that CUB-City introduced in testimony which Staff found to be problematic, and should not be adopted nor given any weight. The first item CUB-City introduced is recent research that indicated that analyst growth rates are upwardly biased. The studies CUB-City witness Mr. Thomas cites tend to report generalized findings and do not specifically suggest that growth rates for utilities are overstated relative to achieved growth. Indeed, one of the studies he cites specifically indicates that analyst growth rate estimates for utilities are not overstated. The authors of that study sorted by growth rate all domestic firms with available IBES long-term growth rate estimates, forming value-weighted portfolios in each quintile after each year, and found that the growth rates for portfolios of companies falling in the highest quintiles (i.e., having the highest growth rates) tend to be overstated relative to the growth achieved over the five years post ranking. However, that study also indicates that the growth rates for portfolios of companies falling in the lowest quintile show no such tendency. That study further notes that the bottom quintile portfolios predominantly comprise firms in mature industries, with approximately 25% of those firms being utilities. Thus, the study does not show that forecasted utility growth rates are upwardly biased estimators of achieved growth five years ex post. (ICC Staff Exhibit 18.0, p. 16)

Next, Mr. Thomas argues that there is a disconnect between the way that investors actually receive cash flows and the way the Commission sets rates which allows a company to recover its approved cost of equity over an entire year, even though investors receive dividend payments on a quarterly basis. He argues that this alleged disconnect makes the quarterly DCF model inappropriate for rate setting purposes. However, Mr. Thomas raised a working capital issue, not a cost of common equity issue. His argument implicitly assumes that working capital is not correctly measured. A working capital allowance compensates a utility for any delay between the time it expends cash to provide service and the time it receives cash from its customer for that service. If a utility is authorized an appropriate working capital allowance, by definition, it will receive cash to pay for all costs of service as they come due. Consequently, if one assumes an appropriate working capital allowance is authorized, Mr. Thomas's argument is invalid because the working capital allowance will eliminate any surplus or deficit in earnings created by the timing of the utility's cash collections and disbursements. Thus, contrary to Mr. Thomas's argument, since utility companies pay cash flows (i.e., dividends) over the course of a year and not all at the end of the year, use of a quarterly DCF model is not only appropriate for rate setting purposes, it is necessary for a utility to recover its true cost of common equity. In fact, the Commission has explicitly rejected the use of an annual DCF model in previous proceedings. (*Id*., pp. 17-18)

Finally, Mr. Thomas's market to book value analysis is based on the premise that one should expect a utility company to <u>precisely</u> earn its cost of capital on a continuing basis. (CUB-CITY Exhibit 1.0, pp. 34-35.) That premise is oversimplified. There are many utility ratemaking practices (e.g., deferred taxes and depreciation) that could result in a utility's market value exceeding its book value. That is, the authorized return for each company in his sample is not the only factor influencing its earnings. Thus, a market to book ratio in excess of one does not necessarily mean the authorized rate of return is too high. (ICC Staff Exhibit 18.0, p. 19)

d. Staff's Recommended Rate of Return on Common Equity

The Commission should accept Staff's estimates of the cost of common equity for Peoples Gas. A thorough analysis of the required rate of return on common equity requires both the application of financial models and the analyst's informed judgment. Because techniques to measure the required rate of return on common equity necessarily employ proxies for investor expectations, judgment is necessary to evaluate the results of such analyses. The models from which Ms. Kight-Garlisch derived the individual company estimates are correctly specified and thus contain no source of bias. Ms. Kight-Garlisch minimized measurement error through the use of a sample, since estimates for a sample as a whole are subject to less measurement error than individual company estimates. Ms. Kight-Garlisch's downward adjustment properly reflects the lower risk of Peoples Gas relative to her Utility Sample. The proper investor-required rate of return on common equity for Peoples Gas is 9.70%. (ICC Staff Exhibit 6.0, pp. 15-16)

2. North Shore

The analysis and arguments regarding the cost of common equity are essentially the same for North Shore as was presented above for Peoples Gas. Staff witness Kight-Garlisch used the same methodology to adjust the Utilities Sample cost of equity to reflect the risk of North Shore as she did for Peoples Gas. However, Staff's revenue requirement recommendations, including Ms. Kight-Garlisch's cost of common equity recommendation, indicated a level of financial strength that is commensurate with an AA credit rating for North Shore. The benchmark financial ratios from S&P for utilities with a business profile score of 3 as well as those resulting from Staff's proposed revenue requirement are presented below in Table 3 – Benchmark Ratios. (*Id*., p. 19)

Table 3 – Benchmark Ratios

	AA	A
Financial Guideline Ratios		
FFO/IC	3.5-4.5X	2.5-3.5X
FFO/Debt	25-30%	15-25%
Total Debt/Total Capital	42-50%	50-55%
Staff Proposal – North Shore		
FFOIC	5.4X	
FFO/Debt		23.6%
Total Debt/Total Capital	44%	

Ms. Kight-Garlisch's recommended cost of common equity for North Shore is 9.50%. The 29 basis point adjustment for North Shore reflects the spread between A rated and AA rated 30-year utility debt yields. This adjustment was derived from the average S&P credit rating of A for the Utility Sample and the implied, going-forward, S&P credit rating of AA for North Shore. (*Id*., pp. 16 and 21)

D. Flotation Costs

Mr. Moul presented an unsubstantiated flotation cost adjustment to the cost of common equity. The Commission Order from Commonwealth Edison Company, Docket No. 94-0065, states that "The Commission has traditionally approved [flotation cost] adjustments only when the utility anticipates it will issue stock in the test year or when it has been demonstrated that costs incurred prior to the test year have not been recovered previously through rates."[11] Moreover, that Order states that "[the utility] has the burden of proof on this issue." Thus, flotation costs are to be allowed only if a utility can verify both that it has incurred the specific amount of flotation costs for which it seeks compensation and that those costs have not been previously recovered through rates. (*Id*., pp. 26-27)

Instead of using the Companies' actual flotation costs, Mr. Moul applied a generalized flotation cost estimate based on "public offerings of common stocks by gas companies from 2001 to 2005." (Peoples Gas Ex. PRM-1.13D, p. 2) The Commission has repeatedly rejected the use of generalized flotation cost adjustments in previous cases as an inappropriate basis for raising utility rates.[12] Thus, Mr. Moul's flotation cost

[11] Order, Docket No. 94-0065, pp. 93-94.

[12] Order, Docket No. 01-0696, September 11, 2002, pp. 23-24; Order, Docket Nos. 02-0798/03-
(continued…)

adjustment should be rejected. Significantly, the Commission rejected North Shore and Peoples Gas' flotation cost adjustment proposal in, Docket No. 91-0010 and 91-0586, respectively. (*Id*., pp. 26-27)

E. Weighted Average Cost of Capital

1. Peoples Gas

Staff recommends a 7.48% rate of return on Peoples Gas' rate base. (ICC Staff Exhibit 17.0, Schedule 17.1) This rate of return incorporates the 4.67% embedded cost of long-term debt agreed on by Peoples Gas and Staff (ICC Staff Exhibit 17.0, p. 6) and the 9.70% rate of return Staff witness Sheena Kight-Garlisch recommends for Peoples Gas' common equity. (ICC Staff Exhibit 6.0, pp. 15-27)

2. North Shore

Staff recommends a 7.69% rate of return on North Shore's rate base. (ICC Staff Exhibit 17.0, Schedule 17.1) This rate of return incorporates the 5.39% embedded cost of long-term debt agreed on by North Shore and Staff (ICC Staff Exhibit 17.0 at 6) and the 9.50% rate of return Staff witness Sheena Kight-Garlisch recommends for North Shore's common equity. (ICC Staff Exhibit 6.0, pp. 15-27)

(continued from previous page)

0008/03-0009 (Cons.), October 22, 2003, pp. 83 and 89; Order, Docket Nos. 01-0465/01-0530/01-0637 (Cons.), March 28, 2002, pp. 75 and 79.

V. HUB SERVICES (All issues relating to Hub services)

A. History of the Hub

Peoples Gas started the Hub to benefit shareholders, not ratepayers.

The Hub was started in conjunction with Peoples Gas' corporate parent, Peoples Energy Corporation ("PEC"), initiating a strategic partnership with Enron. (ICC Staff Exhibit 12.0 Revised, p. 13) The strategic partnership used gas transactions between the two partners to generate unregulated profits, which the partners then split between them. PEC's shareholders obviously benefited from these deals, but the Companies' ratepayers either saw few benefits from or even paid higher prices due to the transaction. (Id.) For example, the partnership might pay Peoples Gas a price below market for utility gas or charge the utility too high a price for a sale to it. Both actions raised gas costs, and the Hub enabled these and other types of transactions. (Id.)

Thus, the Hub was an important tool in the partnership between Enron and PEC. In addition, Peoples Gas diverted Manlove Field usage from Company supply to Hub services. At peak usage, Peoples Gas continued to deliver Hub gas to third party customers and forced utility ratepayers to pay high spot gas prices. The two entities also shared Hub profits. (Id., pp. 13-14)

Ratepayers paid higher costs in Rider 2 because of the strategic partnership for two reasons. As discussed above, Peoples Gas ratepayers supported the Hub by funding high-priced, flowing gas. Also, Peoples Gas did not flow Hub revenues through the PGA (that is, it did not record the revenues as offsets to gas costs in the PGA). [13] But, it did flow the costs to expand Manlove Field through the PGA to ratepayers beginning in April 1999. At that time, Peoples Gas began recording 2% of total Manlove Field gas injections as "maintenance gas."[14] The resulting costs were recovered in the PGA.[15] (Id., pp. 17-18) Recovering maintenance gas in the PGA granted the Company the ability to immediately recover its base gas costs through the PGA. In other words,

[13] Peoples Gas did record the revenues above the line as an offset against base rate gas costs.
[14] Staff notes elsewhere that maintenance gas is base gas.
[15] The Company agreed to stop this practice only after Staff protested this accounting treatment.

Peoples Gas recovered its capital costs to expand the field for non-ratepayer services from Illinois ratepayers immediately, postponed the need to file a rate case, and, in the meantime, retained the Hub revenues for shareholders. This arrangement gave a strong incentive to the Company to offer Hub services even when ratepayers would be worse off. (Id., p. 18)

Peoples Gas acted in bad faith during the strategic partnership period.

The Commission used the Final Order in Docket 01-0707 to inveigh against Peoples Gas' behavior. It included an entire section in the Final Order devoted to detailing the bad faith exhibited by Peoples Gas. The Commission recognized that utility regulation is difficult, if not impossible, without the utility being forthcoming on the facts and behavior. When a utility subverts its entire purpose for shareholder profits and tries to hide its behavior, then the Commission should not give the benefit of the doubt to that utility.

The Order found that the Company's behavior "…during this period move[d] beyond mere imprudence to being egregious. PGL entangled itself in a clever corporate web with its parent company, its affiliates and Enron designed to use PGA assets, assets designated to serve PGL's ratepayers, solely for the gain of the entities involved. … PGL flouted the law and Commission rules, completely disregarded its duty to its PGA customers and jeopardized its credibility. Over the next few years, the Commission intends to closely scrutinized PGL through the audits agreed to in the Settlement Agreement … in hopes that its conduct during this reconciliation is an aberration." (Docket No. 01-0707, Order Dated March 28, 2006, p.138) The Final Order also noted that "…PGL engaged in certain agreements and transactions with enovate and Enron MW that were designed to evade Commission detection. That PGL proceeded in these affiliate interest agreements and transactions without prior Commission approval is an astonishing disregard for and circumvention of the Public Utilities Act and Commission rules." (Id., p. 139) In other words, Peoples Gas was subverted for the profit of Peoples Energy Corporation shareholders. And the Commission would have to watch Peoples Gas closely to ensure that it did not happen again.

The Order goes on to detail the actions that Peoples Gas and its holding company took to accomplish those goals. It states, "People's Energy and Enron developed a strategic partnership that diverted revenues from the regulated utility PGL to its unregulated parent company, PEC, and its unregulated subsidiaries, along with Enron NA, with no corresponding benefit to PGA customers that PGL serves. This strategic partnership used PGL's PGA assets—including gas, contract storage, and Manlove Field operations—and PGL performed transactions and engaged in activities with either enovate, Enron MW, or Enron NA that increased customer gas costs while increasing profits for PGL's parent company, PEC. In sum and substance, revenues were diverted from ratepayers to Peoples Energy and the unregulated affiliates and to Enron. Those revenues should have gone to ratepayers as an offset to the gas costs that they were actually charged." (Id.)

Finally, the Commission noted in the Order that one consequence of its actions was to raise suspicions about whether Peoples Gas could be trusted to fulfill its utility purpose. "The Commission's confidence in PGL's management to be forthright and fair in serving ratepayer interests and in dealing with this Commission is shaken. The Commission believes that its regulatory compact with PGL, its presumption of good faith on the part of PGL's management, and PGL's overall integrity as a corporate citizen is severely damaged by the instant case." (Id., p. 140)

Peoples Gas began the Hub without determining whether it held ratepayers harmless and it still operates it without this consideration.

As noted, Peoples Gas began offering services that directly raised shareholders' profits, but it did not assure itself that ratepayers were not, and would not be, harmed. Peoples Gas did not analyze whether the Hub's benefits were greater than its costs, nor did it determine the best use of the Manlove Field expansion (discussed below). Further, Peoples Gas has never developed a long range operational plan. Finally, neither Mr. Puracchio, the Gas Storage Manager of Peoples Gas nor Mr. Zack, Vice President, Gas Supply of the Integrys Gas Group, could identify the individual who decided to begin offering Hub services. (September 11, 2007 Transcript, Tr., pp. 454-455 and 531) It is not reasonable to expect the customers of Peoples Gas to pay the costs that resulted from the decision to provided Hub Services, when the Company is so embarrassed about its decision that no one will own up to it.

B. It Was Imprudent For Peoples Gas To Offer Hub Services

1. Peoples Gas expanded Manlove Field to start Hub

The base rate resources that produce Hub services are the Manlove Field complex and the Mahomet Pipeline. The Manlove Field complex consists of the gas stored underground, the equipment needed to inject and withdraw the storage gas and the LNG plant. The Mahomet Pipeline transports gas from the storage field to the citygate. There are also expenses to operate the storage field complex and the pipeline. (ICC Staff Exhibit 12.0 Revised, pp. 22-23)

2. Peoples Gas needed to increase base gas in Manlove Field to expand storage capacity

Further as explained in greater detail in section C below, Peoples Gas increased Manlove Field's working gas inventory by 10.2 BCF in order to be able to provide Hub Services. Staff witness Anderson (ICC Staff Ex. 10.0) explains that, to increase the Manlove Field working gas, Peoples Gas needs to inject gas into the field that cannot be withdrawn. Staff witness Anderson estimates that base gas needs to increase by approximately 4 times the amount of the increase in Manlove Field's working inventory. This base gas becomes part of rate base. Since base gas cannot be withdrawn, it is treated as a capital investment by Peoples Gas. (ICC Staff Exhibit 12.0 Revised, pp. 10-11) The Company must eventually increase base gas by more than it has so far. (Id., p. 23)

There are three reasons that Manlove Field is needed to provide firm Hub services. The first reason is peak day deliverability. In order for a service to be firm, the gas must get to its delivery point even on a peak day. The second reason is the total amount of gas that can be delivered during the withdrawal period. The more gas that Hub customers can store, the more valuable their physical hedge against high winter gas prices becomes. Third,, when more capacity is available for Hub Services, more short term deals can be accommodated. Together, these three interrelated factors determine the costs and create the value for Peoples Gas to provide firm Hub services using Manlove Field. (Id., pp. 23-24)

3. Peoples Gas allocates Manlove Field's peak day capacity and working inventory to the Hub and so rates are affected

The Company admits that it allocated 23,899 dth of peak day capacity at Manlove field to Hub services for the period of 1999 - 2006. This is the amount that North Shore surrendered in 1995. However, Peoples Gas also maintains that it did not 'formally' allocate peak day deliverability to Hub customers. For this reason, Peoples Gas did not try to determine whether its 'allocation' was prudent. Instead the Company assumed that the Commission's annual PGA review would be sufficient to determine prudence. (Id., pp. 8-9)

While Peoples Gas admits that it more or less sets aside peak day capacity for Hub customers and that that usage has real value to third party customers, it also seems to contend that it does not make a "formal allocation" to distance itself from the idea that the Hub imposes costs on Manlove Field. Peoples Gas provides Hub Services regardless of whether the capacity is formally 'assigned' to the Hub or not. And it, in fact, may make little difference whether capacity is formally assigned or not. The Company's view that its "informal" allocation somehow eliminates the need to make a prudence decision is wrong. (Id., pp. 9-10) The key factor is whether the Hub continues to offer service during high usage periods. On those days, the Company may be forced to choose between providing services to ratepayers or to Hub customers. (Id., p. 10)

4. Peoples Gas did not examine whether was prudent to expand Manlove Field's working inventory by 40% before starting the Hub

While Peoples Gas investigated whether it could grow Manlove Field, but it never estimated the cost to grow the field, how long it would take to grow the field, or whether ratepayers would benefit from expanding the field. Peoples Gas admitted that it did not conduct a written business case that supported Hub storage services. PG made an important decision without first considering how ratepayers' costs would be affected. Since the costs for base gas at Manlove Field needed to grow the working inventory gas is substantial, not conducting a thorough economic analysis is neither wise nor prudent. (Id., pp. 16-17) It does formulate a budget for the Hub, setting out the Hub's expected revenues and costs. The fiscal year 2006 budget forecast approximately $7 million in operating income ($9 million for revenues and costs of $2 million). In particular, the budget does not assign the costs of additional base gas in Manlove Field to the Hub even though base gas costs are in FERC-approved rates. (Id., pp. 20-21) In contrast, Staff's assessment of the costs versus the benefits of the Hub did. Even at relatively low prices, Hub revenues are less than base gas investment costs. (Id., p. 27)

There is an intuitive explanation for why the Hub is not likely to benefit ratepayers. FERC sets maximum rates that reflect the average cost of the storage field. Base gas costs are a large element of the storage cost. The gas prices are now significantly higher than the cost of gas embedded in existing base gas (approximately $1 per MMBtu). So when additional base gas is added, the average cost of base gas rises, which in turn raises Illinois ratepayers' costs. Dr. Rearden gave an example to demonstrate how this effect works. If the cost to provide a swimming pool for a club of ten individuals is $100, then the cost per person is $10. If the club considers whether to double the pool size to let in ten more people but suppose the cost of adding on to the pool to accommodate ten more people increased the cost by $150, for a total of $250. Splitting the cost 20 ways means that all the members must pay $12.50, which is an increase of $2.50 per person. The original members were paying $10 each, but now they are subsidizing the new members, who pay $12.50 each rather than $15. Manlove Field is likely to require, as explained by Staff witness Anderson, an increment of base gas for expanded capacity of about the same magnitude as for existing capacity. Higher gas prices drive up total cost per unit of capacity, but ratepayers must pay off the costs not recovered from Hub customers. (Id., pp. 28-29)

5. The failure to empirically study prudence is significant

In the fiscal year 2001 PGA reconciliation docket, Peoples Gas claimed to have performed ***no*** study of a five-year contract with Enron under which the utility purchased over half of its supplies. Staff later discovered during its review of millions of pages of Peoples Gas' documents that the Company ***had*** conducted such a study which raised serious concerns over the contract's potential impact on ratepayers. Ultimately, in Docket No. 01-0707, Peoples Gas agreed to include a $100 million refund to the PGA. (ICC Docket No. 01-0707, Order Dated March 28, 2006, pp. 5-6; ICC Staff Exhibit 12.0 Revised, pp. 16-17)

Peoples Gas did not analyze any aspect of the Hub's long term effect on ratepayers. It did not examine the potential revenues from Hub services, the increased costs of base gas or whether the former would exceed the latter. Peoples Gas provides evidence that the "measured expansion" of Manlove might be good for ***Hub*** customers, but it did not look at whether the expansion would be good for ratepayers. The Company appeared to believe that because it ***could*** increase capacity, it ***should***. (Id., pp. 15-16)

Further, Peoples Gas stated in Docket No. 01-0707 that its retail ratepayers would **not** derive any value from the additional capacity at Manlove Field, since its added capacity merely substitutes for other storage services. Thus, Peoples Gas implies that if the additional capacity is used for the Hub, ratepayers are not harmed, but yet they are not likely to derive any benefits if the capacity is used directly to provide utility services. (Id., p. 16)

6. Staff tested the prudence of two Peoples Gas' decisions

The test for whether the Hub does not harm ratepayers is to compare estimated incremental costs with expected Hub revenues. If expected Hub revenues are greater than incremental Hub costs, then ratepayers benefit from the Hub through lower overall rates. However, if expected incremental Hub costs are greater than expected Hub revenues, then offering Hub services was imprudent. And the costs related to Hub services should be disallowed. (Id., p. 20)

The first decision examined was the 1998 decision to start offering Hub services. The working gas inventory at Manlove Field currently devoted to the Hub is 10.2 BCF, while it was 8 BCF in 1998. The increase in working inventory must be supported by additional base gas. Staff estimated that the long run ratio between working gas to base gas at Manlove Field is approximately 22.5%. To expand the field by 8 BCF, Staff believes that Peoples Gas must ultimately inject approximately and additional 36 BCF base gas. (Id., p. 24) Staff estimated that the gas would cost $2.80 per Dth. Thus, the increased base gas would cost about $101 million (= 36 million Mcf x $2.80). At Peoples Gas' 1999 approved rate of return of 9.19%, the annual incremental cost of base gas before taxes is estimated to cost $9.3 million (= 9.19% x 101 million). Staff estimated depreciation by using Peoples Gas' asset life, at the time, of 50 years of straight line depreciation. Base gas depreciation costs $2.0 million (= $101 million / 50) per year. A reasonable estimate for the total annual pre-tax cost for base gas is $11.3 million. (Id., pp. 24-25) Peoples Gas calculated that its expenses were approximately $2.0 million. (Id., p. 25) Thus, Dr. Rearden estimates that the incremental cost of the Hub totals approximately $13.3 million. (Id., p. 26)

Examining the fiscal year Hub revenues over time, Dr. Rearden determined that $10-$12 million was a reasonable, if not high, estimate for Hub revenues. (Id., p. 22) Further, this historical data includes some transportation revenues which are not directly attributable to the Manlove Field. (Peoples Gas calculated that $8.9 million out of $10.1 million (88%) of total Hub revenues were directly connected to the Manlove expansion) (Exhibit TZ 3.6) Peoples Gas should clearly have expected that the cost to inject all the base gas needed at Manlove Field was going to be higher than a reasonable estimate of revenues. By this measure, the Hub is uneconomic. (ICC Staff Exhibit 12.0 Revised, p. 27)

Staff also examined the decision whether or not to keep providing Hub services at this time. Staff examines the decision to support 10.2 BCF of additional working inventory. The cost study considers that Peoples Gas increased base gas by 7.9 BCF since the last rate case. In Exhibit 24.1, Dr. Rearden estimated the cost for the incremental base gas above what Peoples that Peoples Gas is likely to need to add to Manlove Field in order to continue providing Hub services. Dr. Rearden used three different gas costs: $4, $6 and $8 for his study. For all three gas costs, the Hub is a net economic detriment to ratepayers. (ICC Staff Exhibit 24.0 Corrected, p. 27)

In ICC Staff Exhibit 24.1, Dr. Rearden begins with Staff's view about how much base gas Peoples Gas will ultimately have to add to Manlove Field. As discussed above, that totals to 45 BCF. Since Peoples Gas has already added about 8 BCF, it still is potentially liable for an additional estimated 37.4 BCF. If $4 per Dth is the price for base gas, then Peoples Gas might have to invest $181 million in base gas (= $4/Dth x 37.4 BCF). At Staff's proposed return on equity (7.48%), annual costs are $13.6 million. Depreciation, based upon a 75 year life, adds $2.4 million to annual costs (= $13.6 million ÷ 75). Total annual costs are then approximately $16 million, Since Peoples Gas claims that revenues are likely to run to less than $12 million, the Hub cannot hold ratepayers harmless. Of course, $4 gas is at the low end of what is reasonable in today's gas market. At higher gas prices, the cost to inject base gas into Manlove Field is higher. This implies that it is very unlikely that the Hub will be able to pay for itself going forward.

Peoples Gas is trying to include 7.9 MMDth of base gas, valued at about $35 million, into its rate base. The Company allocates 10.2 MMDth to the Hub out of Manlove Field's total capacity of 36.5 MMDth. Staff has estimated that Peoples must inject about 45.3 MMDth of base gas into the field to support its assumed, expanded working inventory. (ICC Staff Ex. 10.0, pp. 21-22) Staff thus concludes that Peoples needs to inject an additional 37.4 MMDth (= 45.3 – 7.9) of base gas. Current gas prices to the Chicago citygate are around $8 per Dth. That means that Peoples Gas is likely to seek recovery of approximately $300 million more of base gas in the next few years. (ICC Staff Exhibit 24.0 Corrected, p. 31)

7. Not all revenues are tied to the increased capacity at Manlove Field

The analyses by both Mr. Zack (North Shore/Peoples Gas Ex. TZ-2.0, p. 7) and Dr. Rearden over-estimate the Manlove Field expansion benefits. They both assume that the entire amount of Hub revenues depend upon Manlove Field's expansion. But Mr. Zack contends that most Hub services and most Hub revenues are interruptible. These services do not necessarily require expansion of Manlove field and its associated costs. Another example is Hub transportation services that move gas between different points on Mahomet Pipeline through displacement. These services do not require any system storage at all. Similarly, Peoples Gas can park gas on the Companies' systems by reducing system deliveries on one day while increasing them on another without involving any storage activity at all. To the extent that revenues do not derive from the field's expansion, they can't really be counted as an expansion benefit. (ICC Staff Exhibit 24.0 Corrected, pp. 27-28) The Company, in its surrebuttal testimony, calculated that all revenues but $1.2 million were closely identified with Hub transactions that were possible only because of the field expansion. (North Shore/Peoples Gas Ex. TEZ-3.0, p. 38)

8. Opportunity costs of the increased capacity at Manlove Field

The estimated costs do not represent the full opportunity cost of Manlove Field's expansion. In particular, Peoples Gas did not examine the value that the extra capacity provides to ratepayers as a physical hedge and for peak day deliverability before it expanded the field. There is no analysis demonstrating that potential additional Hub revenues are adequate compensation for the foregone gas cost reductions that ratepayers might have otherwise received. (ICC Staff Exhibit 24.0 Corrected, p. 25) The Hub generates value by giving access to the Peoples Gas system to Hub customers when it is valuable. Rather than using the system to generate Hub revenues, the Company could instead use them to decrease ratepayers' gas costs. Prior to its surrebuttal testimony, Peoples Gas did not present a study about whether the Hub made ratepayers better or if the Company used the capacity to provide utility services directly to ratepayers (September 11, 2007 Transcript, Tr., pp. 501-502) Increasing Manlove Field's assignment might enable the Companies to substitute Manlove Field storage for leased storage and/or transportation services. (ICC Staff Exhibit 24.0 Corrected, p. 29)

In Surrebuttal testimony, Peoples Gas did present a study, a newly minted calculation that purported to investigate whether the additional capacity (10.2 MMDth) benefitted ratepayers more by using it to offer Hub services or for its ability to physically hedge gas for ratepayers. The study shows that Peoples Gas estimates that the physical hedge is worth $9.3m, while it forecasts Hub storage revenues (those resulting from the expanded Manlove Field) equal to $10m. In addition, if the 10.2 MMDth additional capacity in Manlove Field can be used to store gas for ratepayers, Peoples Gas must earn a return on the expenditures on the increased gas volumes. (North Shore/Peoples Gas Ex. TEZ-3.0, p. 40) The assumptions behind the calculations are captured in ICC Staff Cross Ex. 3 Zack.

There are several factors that undermine the reliability and relevance of the calculations. The physical hedge (the difference between the cost of the gas put into storage and its value upon withdrawal) is estimated to be $9.3 million. That value is derived from August 23, 2007 NYMEX futures prices (September 11, 2007 Transcript, Tr., p. 507). Therefore, it estimates the physical hedge for storing gas presumably starting in the spring and summer 2008 for winter 2008-2009. At the same time, Peoples Gas estimates revenues from Hub storage services will total $10 million. While these are roughly of the same magnitude, they are not directly comparable. Note that revenues of $10 million does not correspond to the total value of Hub storage services to Hub customers, but represents some fraction (not determined, since it is a function of the market) of the value of the physical hedge. In other words, the physical hedge value is likely to be split between the customer and Peoples Gas as the Hub services provider. Either $9.3 million underestimates the physical hedge (see below as well), or Hub revenues of $10 million is not realistic or tied to other years with a different seasonal price differential. To repeat, the total seasonal differential computed in the cross exhibit is less than what represents a fractional amount for the same differential for Hub customers.

9. Peoples Gas' Bad behavior increases gas costs

In the past, Peoples Gas has misallocated the Hub by granting Hub customers better access to deliveries on peak days than utility customers. When Peoples Gas misallocates Hub capacity, then gas costs increase when Hub deliveries are enabled through expensive spot market purchases that assigned to sales and transportation customers. In Docket No. 01-0707, the Commission found that Peoples Gas misused

Manlove Field during fiscal year 2001. Even when annual revenues are higher than annualized base gas cost, ratepayers might be worse off when Peoples Gas allocates too much peak day deliverability to the Hub. Peoples Gas could support deliverability to Hub customers by restricting Manlove Field's use for ratepayers by buying high-priced spot gas to balance its system, thereby raising rates. (ICC Staff Exhibit 24.0 Corrected, p. 30) Peak day deliverability for Hub services has varied over time. From 1999 through 2006, it allocated 23,899 dth per day to Hub services, from North Shore Gas' relinquished capacity. The Company now asserts that that assignment is going to be withdrawn after the rate case: "Peoples Gas is no longer marketing services supported by this peak day deliverability and will not have those obligations after the order in this case." (North Shore/Peoples Gas Ex. TZ-2.0, p. 69; ICC Staff Exhibit 24.0 Corrected, p. 30) However, this change just returns the Hub's situation back to the conditions existing prior to fiscal year 2001. Peoples Gas has not notably increased safeguards against Hub over-subscription above 2001 levels, but Staff is not aware of any safeguard that can prevent, beforehand, the Hub from being used in a way that raises gas costs. (ICC Staff Exhibit 24.0 Corrected, p. 31)

C. Hub Services Impacted Manlove Field

1. Introduction

Staff's review indicated that when Peoples Gas' expanded Manlove Storage Field's ("Manlove") working inventory[16] to offer Hub services, it failed to inject or allocate

[16] Working inventory or top gas is the volume of gas in a storage reservoir that is cycled (withdrawn during winter months, injected during the non-winter months) from storage.

the base gas necessary to support Hub services. For that reason, Peoples Gas' ratepayers are already bearing the cost of additional base gas injected to support Hub services, and it is inappropriate to increase base gas costs and further exacerbate the subsidization of non-jurisdictional activities by Illinois ratepayers.

Peoples Gas failed to conduct any studies to determine the specific amount of base gas needed for Hub operations. This failure is significant because in Docket No. 01-0707 Staff and Peoples Gas agreed that issues relating to base gas needs for Hub operations would be addressed in the rate case instead of Docket No. 01-0707 and at that same time Staff specifically requested Peoples Gas conduct a study to determine the specific base gas requirements caused by the Hub operations. Due to Peoples Gas failure to calculate the base gas needs of its Hub operations, Staff estimates that Hub operations needed to inject about 45 Bcf of base gas into Manlove contrary to Peoples Gas claim that the Hub required no base gas.

Further, Staff demonstrated that when Peoples Gas started to offer Hub services, it altered the manner it operated the Manlove. This alteration allowed Peoples Gas to not only delay injecting the necessary base gas to support Hub operations, but to also place reliance on Illinois jurisdictional customers to support Hub operations. Staff also showed that Peoples Gas' decision to delay the injection of base gas to support Hub operations will cause the cost of that base gas to dramatically increase versus the cost associated with initially injecting the base gas when the Hub operations began.

Finally, Staff demonstrated that Peoples Gas' various claims regarding the Manlove Storage Field are inconsistent and in discussing Hub operations, contrary to the physical operation of an aquifer storage field. Therefore, Staff concluded the 7.88

MMDth of additional cushion gas that Peoples Gas requested in this proceeding should be denied.

2. Basic Operation of Manlove Storage Field

Peoples Gas' Manlove storage field is an aquifer storage field. (ICC Staff Exhibit 10.0, p. 10) An aquifer storage field is a water bearing porous geologic structure in the shape of a dome. The dome can be viewed as an upside down bowl the top of which is covered with an impermeable rock capable of preventing the upward migration of natural gas. Under this impermeable rock is porous water-filled rock. Natural gas is injected under pressure into the pore space of this porous rock, displacing the water. The displaced water forms the seal on the bottom of the injected natural gas to contain it from below. (ICC Staff Exhibit 10.0, p. 10)

A simple analogy of the operation of an aquifer storage field can be related to a person blowing up a balloon. The atmosphere or air on the outside of the balloon represents the water in the aquifer storage field. As the person blows into the balloon, the pressure inside the balloon becomes higher then atmospheric or air pressure outside of the balloon and the balloon inflates. The air blown into the balloon is comparable to gas being injected into the storage reservoir at a higher pressure than the water pressure in the reservoir. When the end of the balloon is opened air is released from the balloon, the air pressure inside the balloon decreases and the balloon deflates as the relative pressures inside and outside of the balloon change. This is similar to how an aquifer storage field works. Gas is injected at higher pressure than the water pressure in the reservoir. The gas volume expands into the reservoir's pore space and displaces the water in the pore space similar to the way a balloon expands and displaces air outside the balloon. On withdrawal, the water migrates back into the gas area because the reduced gas volume also lowers the gas pressure in the reservoir similar to the way releasing air from a balloon lowers the pressure inside the balloon. (ICC Staff Exhibit 22.0, p. 10)

Peoples Gas attempted to portray Staff's balloon analogy as meaning Staff viewed the operation of an aquifer storage field as being a uniform bubble that expands and contracts in a uniform matter as gas is injected and withdrawn. (North Shore/Peoples Gas TLP-3.0, pp. 8- 9 and September 11, 2007 Transcript, Tr., pp. 476-486) However, Peoples Gas' portrayal is not an accurate representation of Staff's viewpoint. Staff's analogy was never meant to indicate that an aquifer operated in this manner. The balloon analogy is meant to represent that as gas is injected into an aquifer above the pressure of the water in the aquifer the gas displaces water from the pore spaces in the reservoir and expands in volume until it reaches equilibrium with the water pressure or injects are stopped. Staff agrees that gas does not expand in a uniform bubble but flows through the pore space by taking the path of least resistance. This procedure was also described by Peoples Gas' witness Puracchio, who referred to this phenomenon as fingering. (North Shore/Peoples Gas Ex. TLP-3.0, p.15)

Thus gas in an aquifer is not distributed uniformly, but fingers by following the path of least resistance. For example, Peoples Gas' witness Puracchio discusses (Id., pp 13- 17) in detail how gas has migrated deeper and further horizontally at Manlove then Peoples Gas wished. However, this is how an aquifer operates since the gas follows the path of least resistance as it displaces water from the pore space in the reservoir. This also means that when Peoples Gas expanded the working inventory at

Manlove field for Hub operations, it could not completely control where that additional gas went; the gas just followed the path of least resistance.

3. Expansion of the Manlove Requires Additional Base Gas

Peoples Gas failed to demonstrate that its expansion of Manlove's working inventory for Hub operations did not also require an expansion in the volume of base gas. Further, Peoples Gas has consistently ignored Staff's concerns regarding the need to support the base gas amounts associated with the Hub operations. In Docket No. 01-0707, Staff and Peoples Gas agreed that the issues involving the proper allocation of base gas between each entity making use of the Manlove storage field would be addressed in Peoples Gas' next rate case. In the same proceeding, Staff specifically requested Peoples Gas, as part of its next rate case filing, to conduct a study to determine the amount of base gas that is required to support the expanded Hub inventory. (ICC Staff Exhibit 10.0, pp. 19-20) However, Peoples Gas failed to conduct any studies that specifically reviewed the amount of base gas needed for Hub operations in this proceeding. (Id., p. 19-21)

Due to Peoples Gas failure to conduct any studies on the volume of base gas required to support Hub operations, Staff used the ratio of inventory gas to base gas prior to the expansion of Manlove for Hub service to provide a rough estimate of the base gas required to support the expanded Hub working inventory. Staff testified that 40 years of operating history at Manlove as well as the operation and theory behind all aquifer storage fields dictate all working inventory requires base gas. (ICC Staff Exhibit 22.0, p. 24) Since the Hub's working inventory is storage and co-mingled in the same geologic formation and under the same conditions as ratepayer gas, those same historic ratio requirements would similarly exist for the Hub. (ICC Staff Exhibit 22.0, p. 21)

Prior to the Hub expansion, Manlove had a working inventory of 27 Bcf and a base gas volume of 120 Bcf which resulted in a ratio of 27/120 which is equal to .225. If the same ratio is used for the 10.2 Bcf working inventory expansion, the result is 45.3 Bcf (10.2/.225 = 45.3) of base gas needed to support Hub operations. Staff's methodology provides only a rough estimate of the base gas required to support Hub operations, but shows the obvious disparity between Peoples Gas' claim of zero and the magnitude of the ultimate base gas volume needed to support current Hub operations. (ICC Staff Exhibit 10.0, p. 21 to 22)

The significant and obvious inequity in Peoples Gas' viewpoint on base gas needs for the Hub expansion is best demonstrated by the below table that shows the classification of gas in Manlove in 1998 and 1999. The data for 1998 is before the expansion of Manlove to provide Hub services. The data for 1999 is after Peoples Gas initially expanded Manlove by 8 Bcf to perform Hub services (the current Hub capacity allocation is 10.2 Bcf). Classification changes are shown as the percentage of change between 1998 and 1999. (ICC Staff Exhibit 10.0, p. 17)

Table 1

	1998 Before Hub	1999 Hub Expansion	% Change
Natural Gas	Volume	Volume	
Top or Working	27.0 Bcf	35.0 Bcf	30 %
Recoverable Base	4.2 Bcf	4.2 Bcf	0 %
Non-recoverable Base	115.4 Bcf	115.4 Bcf	0 %

The table demonstrates that when Peoples Gas expanded Manlove to provide Hub services, it did not add any recoverable and non-recoverable base gas. However, it should be noted that Peoples Gas, in 1999, altered the manner, in which it operated Manlove and began making maintenance gas injections of 2% of injected volumes[17]. At that same time, Peoples Gas started charging its PGA customers, but not Hub customers, with maintenance gas costs. Nevertheless, Peoples Gas wants the Commission to believe the working inventory in Manlove can be increased by 30% (the current 10.2 Bcf volume equates to 40%) to provide Hub services without additional injections of base gas. This is just not rational. All working inventory in Manlove whether for the ratepayer or the Hub requires base gas to operate. (ICC Staff Exhibit 10.0, pp. 17-18)

Peoples Gas attempted to dispute Staff's estimate of base gas requirements by provided an analysis (North Shore/Peoples Gas Ex. TLP-3.0, pp. 19-22) that demonstrated the cushion gas for Manlove Field comprises a higher percentage of the injected gas early in the history of the field, but then falls off in a steady manner after the field began operating. Staff disagrees. Staff does not see any value to Peoples Gas' analysis because it failed to reconcile its claims with its current need to continually inject maintenance gas or base gas to allow Manlove to continue to operate. (ICC Staff Exhibit 22.0, pp. 29- 30) Further, Peoples Gas claim that cushion gas needs are decreasing is also inconsistent with Peoples Gas report that showed the need to

[17] Maintenance gas injections of 2% refer to retaining 2% of all ratepayer injections for base gas. For example, if Peoples Gas injected 100 units for PGA (Purchased Gas Adjustment) customers, only 98 units were available for withdrawal and 2 units went into base gas volumes.

increase the percentage of injections retained for maintenance gas from 2% to 3.5%. (Id., pp. 30-33) In short, Peoples Gas analysis that demonstrates that the cushion gas requirements falls off in a steady manner is nothing but a hypothetical math exercise that ignores the fact that Peoples Gas' latest reservoir study showed Manlove's need for additional maintenance gas is not decreasing, but increasing.

4. How Manlove Works without Hub Base Gas

Prior to initiating Hub operations, Peoples Gas conducted reservoir studies to determine if it could obtain additional gas volumes from Manlove. These studies indicated it was possible to increase the working inventory from Manlove if Peoples Gas continuously grew the field. (Id., pp. 28-29) As a result, Peoples Gas faced a choice when it developed the Hub to either inject the necessary base gas immediately into Manlove or to continually inject base gas. Peoples Gas chose to continually inject base gas. Staff does not disagree that Peoples Gas can operate Manlove in this manner, but this decision caused several additional areas of concern.

First, Peoples Gas decision to change the manner in which it operates Manlove created a situation where ratepayers' existing base gas inventory was used to support Hub operations; thus, creating a subsidy for Hub operations. This topic was already discussed above.

Second, Peoples Gas' choice to delay the initial injection of the base gas necessary to support Hub operations spreads the cost of that additional base gas out over time, but it also creates a situation where the ultimate cost associated with that base gas will increase. For example, the average system gas cost in 1999, when the Hub expansion began was $2.53/Mcf and using Staff's rough estimate of 45.3 Bcf of additional base gas needed to support the current 10.2 Bcf Hub working inventory results in a base gas cost of $114,609,000. However, using the 2006 average system cost of $8.75/Mcf, the cost of 45.3 Bcf of base gas would be $396,375,000. Obviously, Peoples Gas' decision to not inject base gas when Manlove was first expanded to support the Hub will creates a significant cost exposure. Staff's analysis determined that the cost exposure should therefore be borne by the Hub and not Peoples Gas' ratepayers for the future injections of base gas necessary to support the Hub operations. (ICC Staff Exhibit 22.0, p. 32)

5. Peoples Gas Position on Base Gas Needs

Peoples Gas claimed that the expansion of the Manlove working inventory to support Hub services did not require the addition of base gas. (North Shore/Peoples TLP-3.0, pp. 1-4)) Specifically, Peoples Gas stated that early in the operation of Manlove, the gas expansion occurred deeper and further out than would be necessary today for an equivalent amount of inventory. Partly as a result of this, Peoples Gas claimed that most of the working gas growth concurrent with Hub operations took place in areas of the reservoir that were already saturated with gas. Peoples Gas claims this is evident from a reservoir analysis of certain performance over time. (North Shore/Peoples Gas Ex. TLP-2.0, p. 11) Staff disagrees with Peoples Gas' assessment.

As noted above, Peoples Gas never conducted any studies to determine the amount of base gas its Hub operations specifically require. Instead, Peoples Gas' reservoir studies only review the amount of maintenance gas that is continually needed to support the total Manlove inventory. For example, Peoples Gas' study shows

Manlove now needs 3.5%[18] of injected volumes to support Manlove's performance. (Ex. TLP 2.1)) However, as is discussed below, Peoples Gas' approach results in ratepayers subsidizing Hub operations because it ignores the necessity of the additional base gas and causes the ultimate cost of that base gas to dramatically increase.

Peoples Gas' claim regarding the Hub expansion is that all of the gas concentrates into areas of the field that already contains gas and no or limited outward gas movement occurs. However, Staff's review found Peoples Gas' position regarding the Hub expansion to violate the basic premise behind how aquifer storage fields operate. Namely, in order to grow (expand) a field, the gas must move out and expand the current reservoir area. Staff's viewpoint is also consistent with Peoples Gas' witness Puracchio statement that, "Gas in the Manlove Field reservoir is under pressure and tends to expand, radially invading new areas. As this occurs, some of the gas inevitably becomes trapped as cushion gas." (Peoples Gas Ex. TPL-1.0, p. 10)

6. Inconsistencies in Peoples Gas' Hub Base Gas Claims

Peoples Gas' own testimony contains numerous inconsistencies that indicate its claim that the Hub operations have no base gas requirements is contrary to 40 years of operating history at Manlove, and the operation and theory behind all aquifer storage fields that dictate all working inventory requires base gas. (ICC Staff Exhibit 22.0, p. 24)

Peoples Gas originally stated that the expansion of Manlove for Hub services required no additional base gas because it took place in areas of the reservoir that were

[18] Peoples Gas claimed the increase from 2% to 3.5% was insignificant and amount to only 0.6 MMDth (North Shore/Peoples Gas Ex. TLP-2.0, p.9) However, Staff indicated this change was significant because it resulted in an annual increase of maintenance gas costs of $5,250,000. (Staff Ex. 22.0, p. 31)

already saturated with gas and thus did not enter into virgin areas[19] of the aquifer. After Staff took issue with this claim, Peoples Gas amended its statement to claim that some growth at Manlove did occur by invading virgin areas of the aquifer. (North Shore/Peoples Ex. TLP-3.0, pp. 8-12) However, even with that admission, Peoples Gas still contends that Hub injections are being compressed into existing pore space in the center of the field. (North Shore/Peoples Gas EX. TLP-3.0, pp. 17-19) Staff's review indicates Peoples Gas is attempting to vastly understate the need for base gas for Hub operations and those claims are inconsistent with other information in the record.

Peoples Gas provided a graph showing gas saturations, percentage of gas in a certain section of the reservoir, ranging from zero to approximately 60% to 70%. Peoples Gas claimed this graph demonstrates that when gas is injected into Manlove it causes an increase in gas saturations[20] and therefore the Hub expansion did not require additional base gas. (North Shore/Peoples Gas Ex. TLP-3.0, pp. 10-12) Staff disagrees that this graph supports the conclusion that the Hub expansion did not require additional base gas. The graph shows a maximum saturation level of about 65% and any areas that drop to or are below 30% are not producible (gas cannot be removed from those areas). In other words, the maximum concentration of gas in a reservoir is 65% and if gas is withdrawn to a point where the concentration reaches 30%, gas can no longer be removed from the reservoir pore space.

[19] Virgin or new aquifer refers to areas of the aquifer that had not previously had gas injected into them.

[20] Gas saturations increase because the gas is displacing additional water, creating water movement within the reservoir.

However, neither this graph nor any other Peoples Gas' analyses determine what percentage of newly injected gas goes into virgin areas of the aquifer or areas of the aquifer already containing some gas saturation. Further, Staff notes that this graph is consistent with Staff's claims that there is gas lost to the reservoir whenever additional gas is added because gas will enter areas with varying degrees of saturation, displacing water and resulting in lost gas. As is discussed in more detail below, Staff's position is also consistent with the discussion contained in one of Peoples Gas' Manlove reports that indicates during the injection of additional gas, some gas is lost when that gas enter areas of the reservoir that already contained gas (gas saturation above 0%).

In fact, Peoples Gas statements and various reports indicate the obvious need for base gas. Peoples Gas' witness Puracchio stated that, "Gas in the Manlove Field reservoir is under pressure and tends to expand, radially invading new areas. As this occurs, some of the gas inevitably becomes trapped as cushion gas." (Peoples Gas Ex. TPL-1.0, p. 10) Staff does not dispute this statement. However, Peoples Gas made this statement to support the continuous need for maintenance or base gas injections into Manlove to maintain field performance over time, not in relation to Hub expansion. Staff's position is that this statement applies for any additional gas injected into Manlove field including the Hub expansion. (ICC Staff Exhibit 22.0 p. 12 to 13) In other words, as more gas is injected, that gas expands radially into new areas.

Peoples Gas has also indicated that the expansion of working gas without a higher cushion allocation cannot continue indefinitely. (North Shore/Peoples Gas Ex. TLP-2.0, p. 12) Peoples Gas noted that at some point, if growth were to continue, larger quantities of gas would begin to predominantly enter aquifer space not previously occupied by gas and that when and if that occurs, there will be a need for a much higher cushion gas allocation. However, Peoples Gas just expanded the working inventory at Manlove by 40% to provide Hub services and as noted previously, Peoples Gas cannot control where gas expands in the reservoir, the gas just follows the path of least resistance. Further, Peoples Gas already greatly increased the percentage of maintenance gas retained by Manlove base gas injections, from 2% to 3.5%. Obviously, the need for higher cushion gas allocation has already occurred and is due to the Hub expansion.

Aside from Peoples Gas' statements, its own study contradicts its claim that no additional base gas was needed when Manlove was expanded for the Hub. Peoples Gas' February 3, 2003, Report entitled "Manlove Field Trapped Gas Report" discusses gas entering virgin areas of an aquifer including what occurs when an aquifer is expanded or grown. This report (Peoples Gas Ex. TLP-1.1, p. 30) noted that, "The above observations are consistent with past estimates that 56% of gas that moves into virgin aquifer pore space is trapped or lost. Some growth will occur in pore volumes already containing gas, and a much smaller fraction of that gas will be lost. However, <u>most continued growth will invade virgin aquifer with lost gas on the order of 50%</u>." (Peoples Gas Ex. TLP-1.1, p. 30 and ICC Staff Exhibit 22.0, p. 14, emphasis added) Further, the same report indicated "Some growth will occur in pore volumes already containing gas, and a much smaller fraction of that gas will be lost." In other words, anytime additional gas is injected into Manlove a significant amount of that gas is lost. This viewpoint is also consistent with Staff's historical ratio review of Manlove that showed over 75% of the gas in Manlove was base gas.

Even though its own report indicates additional gas is lost even if that area of the reservoir contained gas (gas saturations above zero), Peoples Gas still fails to make any attempt to quantify the volume of gas that was lost in these areas. Obviously, Peoples Gas' argument that that the Hub expansion was brought about mostly by increasing gas saturation falls short. (ICC Staff Exhibit 22, pp. 14-15)

Finally, the February 3, 2003, report (Peoples Gas Ex. TLP-1.1, p. 2) discusses basic aquifer operation, gas saturation, and trapped or lost gas (base gas). In particular, the report noted that "Pressures are necessarily above the initial aquifer pressure most of the time in Manlove. During this time, gas is continually moving from the working gas area into pores that previously had little or no gas saturation. A large fraction of that gas will become trapped, and consequently lost. If this lost gas is not replaced, the effective working gas will decrease by replacing the lost gas itself, and long-term deterioration in field performance will occur…." (ICC Staff Exhibit 22.0 p. 14 to 15) In other words, all additional gas injected into Manlove, (i.e. Hub expansion) forces the field to expand into areas that previously had little or no (virgin) gas or increases gas saturation in existing gas saturated areas by displacing water, both resulting in lost gas.

The obvious truth is that once the reservoir is created, which Peoples Gas did with Manlove in the mid 1960's, all gas additions from that point forward caused the field to expand and this expansion occurs radially and invades new areas of the reservoir. When this occurs, additional gas is trapped, increasing the total base gas volumes maintained by the field. This statement directly correlates with Peoples Gas' explanation that additional gas injected in the Manlove Field expands radially invading new areas when the Manlove field requires maintenance or base gas injections and is also consistent with Staff's testimony, but it is inconsistent with Peoples Gas' claims regarding the need for additional base gas when the working inventory in Manlove was expanded for Hub services. (ICC Staff Exhibit 22.0, pp. 22-24)

All gas injected into the field behaves in the same manner, Peoples Gas just wishes to treat the Hub expansion gas in a differently. Peoples Gas wishes the Commission to believe that only ratepayer gas migrates in Manlove and that the gas inventory for the Hub does not migrate. The Company's position is illogical. All the gas injected into Manlove is above the pressure of the water in the aquifer and will expand and become lost or trapped whether it is ratepayer or Hub gas. There are no individually marked sections of the aquifer to draw from, nor do the gas molecules retain their "Hub" or "ratepayer" IDs. Thus, Peoples Gas' own testimony is inconsistent with the resulting claims it makes regarding Hub operations. There is no set of assumptions that Peoples Gas can create to logically reach its desired result that the Hub requires no base gas.

7. Other Company Studies

Peoples Gas' Exhibit TLP-2.1 is a report that discusses in detail the information and methodology used to construct a new computer model of Manlove. The result of this study showed the need to increase the percentage of injections retained as base gas at Manlove from 2% to 3.5%. Staff does not dispute the need to increase the percentage of injections retained for base gas injection from 2% to 3.5%, but has some concerns that this study could ultimately understate the needed percentage of injections retained since Peoples Gas did not initially inject base gas when it began Hub operations.

Staff noted that Peoples Gas needed to calibrate or match the new reservoir modeling results to the actual historic Manlove field performance. To calibrate the model, the model assumptions for the geologic data are varied until the model matches the actual historic performance of the field. When an aquifer field like Manlove is operated in a relatively stable and consistent manner, performance can be reasonably predicted. However, Staff is concerned with the model results because the time period (1997-2006) used to calibrate the new Manlove model was during a period of considerable change at the field. (ICC Staff Exhibit 22.0, pp.16-20)

Peoples Gas increased the working inventory in Manlove in order to provide Hub services. The working inventory was increased to approximately 8 Bcf (30% increase) and finally to 10.2 Bcf (40% increase). Next, Peoples Gas changed its historic practice of only injecting maintenance or base gas to support Manlove operations when field performance deteriorated to continuously injecting maintenance or base gas at a rate of 2% to 3.5% of the injected volume. Finally, Peoples Gas withdrew gas from Manlove during the summers of 2000 and 2002. This is the only time in the history of the Manlove field that gas was withdrawn during the injection season. Obviously, these major changes make comparison between prior periods and the period involving expanding working inventory, continuous base gas injections, and summer withdrawals, problematic. (Id., pp. 16-20)

Further, Peoples Gas' February 3, 2003, report indicated in relation to reservoir models that "It should be realized that the predictions of the simulations are for specific operating conditions and injection/withdrawal schedules that were imposed, and that those conditions did not change from year to year in the predictions. This is certainly not the situation in the field, but future operating conditions are difficult to predict and incorporate into reservoir performance predictions." (ICC Staff Exhibit 22.0, pp. 19-20) Staff noted that this statement demonstrates the difficulties in simulating Manlove reservoir performance.

Staff is concerned that the changing operating conditions at Manlove, since the Hub expansion, have created a situation that makes predicting Manlove performance difficult. (Id., pp. 19-20) In fact, Staff's biggest concern is that the new reservoir study's determination that 3.5% of injections must be retained could understate the additional cushion gas needs at Manlove.

8. "Benefits" of Hub

Peoples Gas claimed there is an operational benefit to Hub operations. Specifically, Peoples Gas indicated the Hub expansion has extended Manlove's decline curve and this extension benefits the ratepayer. (ICC Staff Exhibit 22.0 pp. 34-35) However, Peoples Gas failed to provide any studies or other documentation to support this statement.

Further, Peoples Gas made the same claim in Docket No. 01-0707, which the Commission rejected. In that proceeding, the Commission's Order on page 80 indicated, in part:

> Mr. Puracchio testified that PGL cycled more than 27 Bcf of gas per season at Manlove. Injecting more gas extends the field decline point, which extends how long Manlove is useful for storage. When more gas is injected, less gas becomes trapped. (Id. At 7; Tr. 681) During the time period in question, PGL personnel successfully extended the decline point of Manlove, which increased Manlove Field's storage capability. (Tr. 681) <u>PGL presented no evidence establishing that this increase capacity was used to benefit consumers directly, through use of this extra capacity, or</u>

> indirectly, through profits from the use of this extra capacity. (Illinois Commerce Commission, On Its Own Motion, v. Peoples Gas Light and Coke Company, Reconciliation of revenues collected under gas adjustment charges with actual costs prudently incurred., Docket No. 01-0707, Order p. 80, (March 28, 2006))
>
> (ICC Staff Exhibit 22.0 p. 34 (emphasis added))

Peoples Gas has merely restated the same claim it made in Docket No. 01-0707, without any corroborating analysis or proof. Therefore, consistent with the Commission's prior Order, Peoples Gas has failed to show any benefits that accrue to rate payers as a result of Hub operations. (Id., p. 35)

9. Peoples Gas Alternative Base Gas Calculation

Peoples Gas, in its surrebuttal testimony (North Shore/Peoples Gas Ex. TLP-3.0, pp. 1-2) provided an alterative to Staff's recommendation to disallow the full 7.88 MMDth of base gas that Peoples Gas wishes to add to base rates. Peoples Gas maintains that by Staff's own logic there is no reason not to allow at least 6.54 MMDth of the 7.88 MMDth in the rate base since it is clear from Staff's testimony that a certain amount of cushion/maintenance gas would have been required even if no increase in working gas for Hub operations had occurred. Specifically, Peoples Gas (Ex. TLP-2.0 and EX. TLP 2.8) broke down the 7.88 MMDth year by year and arrived at 1.34 MMDth as being the quantity associated with the expansion of Manlove for Hub operations. The difference of 6.54 MMDth (7.88 MMDth – 1.34 MMDth), according to Peoples Gas, is the amount of cushion gas that would have been required even if no increase in working gas occurred. Staff disagrees with the Company's conclusion and logic.

As noted above, when Peoples Gas created the Hub, it changed the manner in which it operated Manlove. As a result, Peoples Gas did not immediately inject the base gas necessary to operate the Hub, but instead determined an annual percentage of maintenance gas to retain from ratepayer injections. In other words, Peoples Gas has never determined what base gas volume was required to support the 10.2 Bcf of Hub inventory.

Next, as is also noted above, the expansion of inventory at Manlove results in the loss of a portion of that additional gas as soon as that gas is injected. However, Peoples Gas calculation is an incremental measurement that ignores the initial gas lost as a result of the working inventory expansion or that the historic working to base gas ratio will prevail in the future.

Further, Staff would point out that Peoples Gas, in 1999, changed the manner it placed gas into Manlove by placing maintenance gas costs through the PGA. It was not until the 2001 PGA (Docket No. 01-0707) reconciliation that the Commission directed Peoples Gas to cease that activity. From the time Peoples Gas changed its policy (1999) through the day prior to the start of the 2001 PGA reconciliation, Peoples Gas passed additional base gas costs to ratepayers through the PGA. Therefore, ratepayers have already incurred the cost for some additional base gas since Peoples Gas' last rate case.

Finally, when Peoples Gas stopped passing the maintenance gas costs through the PGA, it only took that maintenance gas percentage from ratepayers, not from any Hub operations. For example, Peoples Gas currently retains 3.5% (up from 2%) of all ratepayer injections into Manlove, but every unit injected into Manlove for the Hub is allowed to be removed. (Tr. 456-457)

All of the above information indicates that Peoples Gas' alternative approach falls short in allocating the proper amount of base gas requirements to the Hub and that Staff's recommendation to disallow all of the requested additional cushion gas amounts is the most appropriate solution.

10. Failure to Comply with Commission Order

Staff also considers Peoples Gas failure to determine the base gas needs and requirements to support Hub operations as contrary to the requirements the Commission dictated in its 01-0707 Order. Specifically, the Order stated that:

> Peoples Gas Light and Coke Company shall revise its maintenance gas accounting procedures related to gas injected for the benefit of North Shore Gas Company and third-parties to require those entities to bear the cost of maintenance gas, and it shall revise its maintenance gas accounting procedures to ensure that all customers/consumers bear equal responsibility for maintenance gas.

(01-0707, Order at 9)

Staff's review has found no indication that Peoples Gas made any attempt to comply with this requirement. Staff's cross examination of Mr. Puracchio, the storage manager at Manlove since 2001(Tr. 447), found that he did not know what Peoples Gas had done to comply with the above section of the Commission's 01-0707 Order (Tr. 455) and he also indicated that prior to the filing of his rebuttal testimony, he had never attempted to determine the appropriate percentage of maintenance gas to allocate to Hub operations. (Tr.456) In other words, the person responsible for Manlove field and the most logical person to determine the base gas needs of the Hub had never been asked to make such a determination. Therefore, Peoples Gas, notwithstanding the Commission's finding in the 01-0707 Order, has not bothered to determine what base gas volumes it should assign to Hub operations. Staff's review of Peoples Gas' actions on this area show a concerted effort to avoid directly addressing this very important and essential issue. Staff can only conclude that its review demonstrating Peoples Gas' ratepayers are providing a large subsidization to Hub operations is accurate, and Peoples Gas does not wish to acknowledge this inequity.

11. Conclusion

Staff believes the total 7.88 MMDth (about 7.88 Bcf) volume of base gas, valued at $39,019,000 should be denied in rate base treatment. Peoples Gas failed to demonstrate that the addition of 10.2 Bcf of Hub working inventory does not require base gas. Staff estimated, from the historic ratio of inventory at Manlove, that the Hub operations will require about 45 Bcf of base gas, which is the only estimate of base gas requirements in the record, since Peoples Gas failed to conduct any studies that specifically calculated that amount even though such studies were specifically requested in Docket No. 01-0707. Further, Peoples Gas' reasons for not allocating base gas to Hub operations is illogical and contrary to 40 years of operating history at Manlove as well as the operation and theory behind all aquifer storage fields that dictate all working inventory requires base gas. In short, Peoples Gas failed to demonstrate the just and reasonableness of its requested base gas costs; therefore, those base gas costs should not be allowed into base rates.

D. Remedies For Peoples Gas Decision To Offer Hub Services

1. Hub service costs which were imprudent must be excluded from base rates

An increase in rates requires, under Section 9-201(c) of the Public Utilities Act ("Act"), a finding that the new rates are "just and reasonable." (220 ILCS5/9-201(c)) The burden of proof thus rests on the utility to, "prove the reasonableness of the values it places on the components of the revenue requirement," including a "show[ing] that its operating costs are reasonable, [and] its rate base is the reasonable value of its property used for serving the public." (Citizens Util. Bd. v. Illinois Commerce Comm'n, 276 Ill.App.3d, 730, 746, 658 N.E.2d 1194, 1206 (1st Dist. 1995) In regard to Peoples Gas' operation of Hub Services in particular at Manlove Storage Field, Staff contends, and the evidence supports, that the Company has failed to prove its costs of operating the Hub are just and reasonable, and therefore, those costs both rate base and operating expense should not be considered when determining the Company's base rates.

Given that Staff has demonstrated that the expansion of Manlove field to support hub services is imprudent, the recovery of the cost of this expansion from ratepayers is improper. Therefore, Staff recommends that the base gas costs of $39,018,791.41 that Peoples Gas is proposing to add to rate base since the last rate case be disallowed. As support for the Hub, they are uneconomic and imprudent. In addition, Staff recommends that the Peoples Gas' reported Hub expenses should also be disallowed from rates. Staff's recommendation is described in Schedule 12.1, attached. (ICC Staff Exhibit 12.0 Revised, pp. 29-30)

2. Peoples Gas should stop offering Hub services

Staff recommends that the Commission order Peoples Gas to cease providing Hub services. The Commission should do this, since the provision of Hub services by Peoples Gas using the increased capacity at Manlove Field is likely to impose higher costs upon ratepayers in the coming years. Staff demonstrates its view that those costs are higher than revenues, and that the revenue shortfall will be ultimately borne by ratepayers. Further, Staff also shows that Peoples Gas can manage Manlove Field in a way that imposes even more costs on ratepayers. As seen in Docket No. 01-0707, if the utility grants too much peak day deliverability at Manlove Field to Hub customers, then in order to balance its system, the Company will have to enter into transactions whose costs are recovered in the PGA from system supply customers, further raising PGA gas costs. (Id., pp. 32-33)

In Companies' witness Zack's rebuttal testimony he states that the Company no longer schedules services that call on peak day deliverability. (North Shore/Peoples Gas EX. TZ-2.0, p. 69) Staff is skeptical this statement reduces the risk that ratepayers might cross-subsidize Hub services. There are two reasons why the Company's statement is not adequate protection for ratepayers. First, Peoples Gas has not always interrupted Hub services during periods when the capacity could be used for ratepayers. (ICC Staff Exhibit 24.0 Corrected, p. 34) Second, it is an extremely complex task to allocate Manlove Field usage between three groups of customers (ratepayers, transport customers and Hub customers). It is not easy to detect how much a given transaction relies on peak day deliverability. A much cleaner protection for Peoples Gas' system supply customers is for the Company to simply desist from Hub transactions. (Id., pp. 34-35)

3. Peoples Gas' failed to obtain Commission approval to use, appropriate or divert its money, property and resources to expand Manlove Field and offer Hub services therefore those costs cannot be included in rates

Should the Commission not find imprudence on the part of Peoples Gas for expanding Manlove Field in order to provide Hub services the costs for the expansion of Manlove field should still not be recovered in rates. The cost should still not be recovered in rates given that Peoples Gas never obtain prior Commission approval to use, appropriate or divert its money, property and resources to expand Manlove field as required by Section 7-102(A)(g) of the Public Utilities Act ("PUA"). (220 ILCS 5/7-102(A)(g) The failure to obtain prior Commission approval results in those costs not being recoverable in rates as required by Section 7-102(E) of the PUA as discussed below. (220 ILCS 5/7-102(E))

Peoples Gas' Hub required Illinois Commerce Commission ("ICC") approval under Section 7-102(A)(g) of the PUA. Peoples Gas without ICC approval, used, appropriate or diverted its money, property and resources (220 ILCS 5/7-102(A)(g) to the Hub business. Peoples Gas' witness Mr. Zack's own rebuttal testimony supports the position that money, property and resources of Peoples Gas were and are being used to operate the Hub business. ("All incremental expense associated with the Hub was absorbed by Peoples Gas." (North Shore/Peoples Gas Ex. TZ-2.0, p. 67) "All the costs and revenues associated with the Hub and the base rate assets that support the Hub are accounted for above the line" (Id., p. 68))

Peoples Gas began its Hub business in March of 1998 (North Shore/Peoples Gas Ex. TZ-2.0, p. 66) According to Peoples Gas, the revenues from its Hub for fiscal year 2001 to 2006 were approximately as follows: $6.8 million; $11.6 million; $11.2 million; $7.6 million; $10.6 million; and $10 million, respectively. (ICC Staff Exhibit 12.0 Revised, pp. 21-22) In addition, Peoples Gas expects the revenues from the Hub for fiscal year 2007 to exceed $10 million. (North Shore/Peoples Gas Ex. TZ-2.0, p. 70, lines 1549-1551) In order to generate revenues of this size, significant moneys, property, and other resources must have been appropriated or diverted to the Hub business from the utility. This conclusion is supported by the testimony of Peoples Gas witness Zack that if Peoples Gas' Hub had not been in business some or all of the Manlove capacity for the Hub could have been used to serve utility customers. (North Shore/Peoples Gas Ex. TEZ-3.0, p. 39) It is further supported by Mr. Zack's testimony that over $7 million of incremental compressor fuel costs have been borne by Peoples Gas (North Shore/Peoples Gas Ex. TZ-2.0, p. 69)

Staff's application of Section 7-102(A)(g) to Peoples Gas' Hub is appropriate. Section 7-102(A)(g) of the PUA provides as follows:

> "(A) Unless the consent and approval of the Commission is first obtained or unless such approval is waived by the Commission or is exempted in accordance with the provisions of this Section or of any other Section of this Act:
>
> * * *
>
> (g) No public utility may use, appropriate, or divert any of its moneys, property or other resources in or to any business or enterprise which is not, prior to such use, appropriation or diversion essentially and directly connected with or a proper and necessary department or division of the business of such public utility; provided that this subsection shall not be construed as modifying subsections (a) through (e) of this Section."
> 220 ILCS 5/7-102(A)(g).

Under section 7-102(A)(g), a public utility must obtain approval from the Commission before it may employ its public utility resources in new ventures that are not "essentially and directly connected with or a proper department or division" of the utility's business. There should be no dispute that Peoples Gas' Hub business is not essential or directly connected with utility business. The following colloquy between ALJ Moran and Peoples Gas witness Mr. Thomas Puracchio, supports that position.

[ALJ Moran]

Q. Do Hub services use a resource that is needed to serve Peoples Gas customers.

[Mr. Puracchio]

A. My understanding is that Hub services take advantage of excess capacity.

[ALJ Moran]

Q. So none of that that is left open for Hub services is really necessary for Peoples' customers –

[Mr. Puracchio]

A. That's my understanding.

[ALJ Moran]

Q. -- its just excess?

[Mr. Puracchio]

A. That's my understanding.

(Tr., p. 458)

In addition, Peoples Gas in effect acknowledges that the Hub was "not, prior to such use, appropriation, or diversion essentially and directly connected with or a proper and necessary department or division of the business of such public utility[.]"(220 ILCS 5/7-102(A)(g) by Mr. Zack's testimony that if the Commission were to order Peoples Gas to stop providing Hub services, the services could be phased out over time. (North Shore/Peoples Gas Ex. TEZ-3.0, p. 43) If the Hub was essential to utility business no such phase out would be possible.

A number of court cases and Commission orders have considered the application of section 7-102(A)(g), or one of its statutory predecessors, in a variety of circumstances. While the focus in several of the decisions is on whether approval should be granted or denied, and not on the threshold question whether the activity at issue is one that requires approval under the statute, those cases provide guidance for they illustrate the types of activities that are assumed to require approval from the Commission under that provision. A consideration of these decisions and orders support Staff's position that approval should have been obtained from the ICC by Peoples Gas before Peoples Gas began operating the Hub.

Courts in several cases have construed or discussed section 7-102(A)(g) or its statutory predecessors, section 7-102(g) and section 27(g). One recent decision involving the statute is Commonwealth Edison Co. v. Illinois Commerce Comm'n, 295 Ill. App. 3d 311(1998). In that case, Com Ed had sought permission from the Commission to provide energy support services to certain customers. The Commission denied the utility's request, and Com Ed challenged that decision before the appellate court. "The petition and a later amended petition described energy support services as including the following: the furnishing, design, engineering, construction, operation, analysis, and management of electrical power equipment, energy systems, and energy conversion systems; the selection, evaluation, acquisition, installation, and testing of equipment used in such systems, including energy efficiency and conservation equipment; and the auditing and monitoring of such energy systems." (Commonwealth Edison Co. v. Illinois Commerce Comm'n 295 Ill. App. 3d at 314) Classification of those activities as ones that would require approval under section 7-102(a)(G) was not at issue; rather, the company assumed that approval would be needed in the first place, and the issue on appeal instead was whether the Commission had acted properly in denying permission. As it turned out, the appellate court affirmed the Commission.

In People v. Phelps, 67 Ill. App. 3d 976, a criminal prosecution for violations of the provisions now found in section 7-102 of the PUA, one of issues on appeal was the threshold question whether the particular activity involved was something for which Commission approval was necessary under the statute. In that case, an attorney who owned controlling interests in a water utility and in an affiliated holding company was charged with violating section 27(g) after the water company borrowed more than $1 million and then transferred that sum to the holding company without first obtaining approval of the transactions from the Commission. The defendant argued, among other things, that the transfers from the water utility, Eastern, to the holding company, Water Securities, did not come within the scope of the statute because they were to a company that should be considered essentially and directly connected with the utility business. The appellate court rejected this argument, explaining, "This contention cannot be upheld. Water was engaged in investments, many of them highly speculative, which had absolutely no connection with the business of Eastern. To hold as defendant would have us, again, would completely contradict the provisions of the Act, and nullify its stated protection of the public." People v. Phelps, 67 Ill. App. 3d at 980.

In Peoria Chapter, National Electrical Contractors Association, Inc. v. Illinois Commerce Comm'n, 37 Ill. 2d 55 (1967), a party filed a complaint with the Commission challenging a contract entered into by CILCO and the state Department of Public Works and Buildings under which the utility company would provide power to and maintain state-owned street lights in a certain area. The complaint contended that the contract was one that required advance approval under section 27(g) of the PUA. The Commission's approval of the contract did not come until after it was executed, however, and the complaint alleged that the contract was therefore void. The supreme court upheld the Commission's determination that advance approval was not required. The court explained, "From the uncontradicted evidence, however, the Commission found that street lighting maintenance services 'are a part of one of the oldest services rendered by [CILCO] as an electric public utility.' We agree with the Commission that the statute did not require prior approval of the contract." (Peoria Chapter, National Electrical Contractors Association, Inc. v. Illinois Commerce Comm'n 37 Ill. 2d at 58)

The Commission has considered in several different contexts requests for approval of activities under section 7-102(A)(g), or earlier versions of the same statute. Recently, in MidAmerican Energy Co., Docket No. 03-0659, the Commission considered a petition by a company seeking a declaratory ruling regarding the appropriate regulatory treatment of its competitive gas sales within its Illinois service area, which had not previously been approved. The Commission explained the operation of the statute and its application to MidAmerican's transactions:

> As a public utility, MEC may not, pursuant to Section 7--102(A)(g), use, appropriate, or divert any of its property or other resources in or to any business or enterprise which is not essentially and directly connected with or a proper and necessary department or division of MEC's public utility business without prior Commission approval. With regard to MEC's competitive gas sales inside of its service territory, it is clear that MEC is using some of the same transportation and distribution facilities it uses to serve regulated customers to serve competitive customers. Clearly, the making of competitive gas sales is not essential or directly connected to MEC's ability to serve its bundled and transportation customers. MEC is fully capable of serving its bundled and transportation customers without engaging in competitive gas sales. Nor are the divisions within MEC that make the competitive gas sales necessary divisions of MEC's gas public utility business. The absence of the Trading Division and Marketing and Sales Division will not impair MEC's ability to serve its bundled and transportation customers.
>
> Notably, no evidence exists that MEC has received Commission approval to use any of its facilities in connection with competitive gas sales within its service area. MEC's assertions that it has accounted for all property used in its regulated gas sales and competitive gas sales inside its service

> area and uses separate employees to acquire gas supply does not obviate the need to abide by Section 7-102. If a utility's commitment to distinguish property and personnel were sufficient, the General Assembly's adoption of Sections 7-205 and 7-206 and the requirement for Commission consent and approval in Section 7-102(A) would be unnecessary. Accordingly, in the absence of Commission permission, MEC is prohibited from selling gas at competitive prices in its traditional service area using the same property used to serve regulated customers."

(Docket No. 03-0659, Final Order at (May 11, 2004, at 18))

The Commission later allowed rehearing on a portion of the May 2004 final order; on rehearing the Commission reiterated its concerns over MEC's diversion of public utility assets into new and unrelated lines of business. (MidAmerican Energy Co., Docket No. 03--0659, Order on Rehearing (Nov. 10, 2004)) The Commission's order on rehearing was clear though that "[its] finding is strictly limited to the competitive gas contracts [of MEC]. The question of whether Commission approval of MEC's diversion of money resources into the creation and operation of its competitive division in necessary under Section 7-102 is not a question being considered on rehearing." (Id. at 10)

The Commission has dealt with the same provision in a number of other contexts, applying it to agreements with affiliates regarding cash management services involving a water utility (Illinois-American Water Co., Docket No. 00-0306 (May 16, 2000)), the provision by an electric utility of "open access participation" to certain customers, a precursor of competitive sales of electricity (Central Illinois Public Service Co., Docket No. 96-0134 (August 7, 1996)), the lease of storage space in oil tanks at an electric utility's generating plant (Commonwealth Edison Co., Docket No. 96-0175 (June 26, 1996)), and the provision by local exchange carriers of cable television services and direct broadcast satellite services (Madison Telephone Co., Docket No. 94--0115 (May

3, 1995); Harrisonville Telephone Co., Docket No. 93--0174 (July 8, 1993)). In each of those cases, the utility in question submitted a petition seeking permission under the provision now found in section 7-102(A)(g) of the Act to engage in the particular activity at issue.

In Commonwealth Edison Co., Docket No. 96-0175, cited above, Com Ed sought and obtained permission under what was then section 7-102(g) to lease to other companies storage space in fuel tanks at one of its power plants. In a sense, the fuel tanks there were to operate as a fuel "hub," of sorts, for local refiners and others who needed on a temporary basis extra storage capacity. The Hub established by Peoples Gas was a much more extensive undertaking, as the record in this case has shown. In addition, if Com Ed needed approval for what may be characterized as a small fuel hub, then by the same token approval was necessary here for the Hub established by Peoples Gas, which represented the rendition of new types of services by the company ("The Hub is two types of FERC-jurisdictional services. First, the Hub includes the transportation and storage services provided by Peoples Gas pursuant to a FERC Operating Statement. Second, it includes other interstate services provided pursuant to FERC's rules authorizing sales for resale at negotiated rates." (North Shore/Peoples Gas Ex. TZ-2.0, p. 65)). The other cases and decisions cited above similarly lend support to or are consistent with the view that the activity involved here was something for which prior approval was necessary under section 7-102(A)(g).

While Section 7-102(E) exempts certain transaction from ICC approval, section 7-102(E) does not exempt Peoples Gas Hub business from ICC approval for several reasons. First, Section 7-102(E) provides in part that:

> The filing of, and the consent and approval of the Commission for, any assignment, transfer, lease, mortgage, purchase, sale, merger, consolidation, contract or other transaction by an electric or gas public utility with gross revenues in all jurisdictions of $250,000,000 or more annually involving a sale price or annual consideration in an amount of $5,000,000 or less shall not be required. …

(220 ILCS 5/7-102(E)) The primary rule of statutory construction is to ascertain and give effect to the intent of the legislature. (Bruso v. Alexian Brothers Hospital, 178 Ill. 2d 445 (1997) In determining the legislatures' intent, the court considers the plain and ordinary meaning of the statute's language in the overall context of it reason and necessity and its stated purpose. (Illinois Bell Telephone Co. v. Illinois Commerce Comm'n, 282 Ill. App. 3d 672 (1996) The plain language Section 7-102(E) "sale price or annual consideration" does not make any logical sense when it is applied to the diversion of money or resources set forth in Section 7-102(A)(g)n since no sale price or annual consideration arises in such a situation. Therefore Section 7-102(E) does not apply.

Second, if the exemptions under Section 7-102(E) apply which they do not, the "annual consideration" limit of $5 million has been exceeded by Peoples Gas' Hub for fiscal years 2001 to 2006 (ICC Staff Exhibit 12.0, pp. 21-22) and is expected to exceed that figure for fiscal year 2007 (Zack Rebuttal, TZ-2.0, p. 70, lines 1549-1551) Therefore, the Hub would still require approval under Section 7-102(A)(g). For all of the above state reasons the Commission should find that prior approval was necessary under section 7-102(A)(g) for Peoples Gas' Hub.

Given that Peoples Gas failed to obtain Commission approval for the use, appropriation and diversion of assets to set up the HUB the question arises as to what should be done with those costs. Section 7-102(E) and case law under Section 7-101 make it clear that those costs cannot be recovered by Peoples Gas since the use, appropriation and diversion of assets are void. Section 7-102(E) provides that:

* * *

> Every assignment, transfer, lease, mortgage, sale or other disposition or encumbrance of the whole or any part of the franchises, licenses, permits, plant, equipment, business or other property of any public utility, or any merger or consolidation thereof, and every contract, purchase of stock, or other transaction referred to in this Section and not exempted in accordance with the provisions of the immediately preceding paragraph of this Section, made otherwise than in accordance with an order of the Commission authorizing the same, except as provided in this Section, shall be void.

* * *

(220 ILCS 5/7-102(E). Since there was not Commission approval they are void.

Similar language appears in Section 7-101(3)

> Every contract or arrangement not consented to or excepted by the Commission as provided for in this Section is void.

(220 ILCS 5/7-101(3) In a prior decision the court interpreted the effect of a contract being void due to the failure of a party to obtain Commission approval under Section 7-101. In *Metro Utility Co. v. Ill. Commerce Comm'n*, 262 Ill. App.3d, 266 the court found that "because under Section 7-101 unapproved affiliated interest contracts are void, the Commission is required to disallow such contracts in a ratemaking case." (*Id.*) Therefore, just as in Metro the failure by Peoples Gas to obtain Commission approval results in those Hub costs being disallowed in its rate case.

If the Commission does not accept Staff's recommendation that Peoples Gas cease operating the Hub, the Commission should direct Peoples Gas to seek approval from the Commission to operate the Hub in accordance with Section 7-102(A)(g).

E. Manlove Capacity Standards

Staff raised a concern that Peoples Gas had increased its leased storage capacity volumes while at the same time reducing its own allocation of Manlove storage capacity in favor of the Hub. (ICC Staff Exhibit 23.0, p. 14) Staff recommended that Peoples Gas develop procedures to document how it allocates capacity from the Manlove storage field and how it ensures that rate payers are not harmed by its decision. (Id.) Staff recommended that Peoples Gas provide this information to the Director of the Energy Division within 60 days of the Commission's Final Order in this proceeding. (Id.) Peoples Gas agreed with Staff's proposal, but requested 120 days instead of the 60 days recommended by Staff. (North Shore/Peoples Gas Ex. TEZ-3.0, p. 38) This change is acceptable to Staff. Therefore, it is uncontested that Peoples Gas will provide to the Director of the Energy Division within 120 days of the Commission's Final Order in this proceeding, procedures to document how it allocates capacity from the Manlove storage field and how it ensures that rate payers are not harmed by its decision.

VI. WEATHER NORMALIZATION – AVERAGING PERIOD

VII. NEW RIDERS

A. Overview

In addition to seeking increases in their base rates, both Peoples Gas and North Shore propose to implement multiple new riders by their tariff filings. The individual riders being proposed are the Volume Balancing Adjustment ("VBA") rider or, in the alternative, the Weather Normalization Adjustment ("WNA") rider, the Infrastructure Cost Recovery ("ICR") rider (for Peoples Gas only), the Enhanced Efficiency Program ("EEP") rider, and the Uncollectible Balancing Adjustment ("UBA") rider. While tariffs containing riders or automatic adjustment clauses have been judicially sanctioned in Illinois since 1958, the rider proposals by Peoples Gas and North Shore are novel and present significant legal, policy and factual issues. As will be explained in more detail below, Staff's review of the Companies' rider proposals reveals an abundance of infirmities and deficiencies that cause Staff to recommend that the Commission decline to adopt each of the rider proposals. Given the multitude of rider proposals presented in this proceeding, Staff will begin by providing a comprehensive review of Illinois case law addressing the legal principles governing the Commission's discretionary authority to approve riders. Staff's review of relevant case law is presented, in general, on a chronological basis.

1. Use of Riders Under Illinois Law

a. Traditional Ratemaking

The alternative methods by which rates are set by the Commission was succinctly summarized by the First District appellate court:

> The theory behind public utility regulation is that the Commission should fix rates that "might properly be supposed to result from free competition." *State Public Utilities Comm'n v. Springfield Gas & Electric Co., 291 Ill. 209, 218, 125 N.E. 891, 896 (1919)*. It is undisputed that **the Commission sets rates in two ways -- by base rates or by an automatic-cost-recovery mechanism. Base rates attempt to recover a utility's costs through estimating the total revenues necessary to recover its operating costs plus a cost of investor capital using a specific formula.** *Citizens Utilities Co., 124 Ill. 2d at 200-01, 124 Ill. Dec. 529, 529 N.E.2d at 512-13*. There are circumstances, however, where

> particular utility costs are unique enough that circumstances warrant a recovery through an automatic-cost-recovery mechanism. *Citizens Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d 111, 138, 651 N.E.2d 1089, 1102, 209 Ill. Dec. 641 (1995)*. In *City of Chicago v. Illinois Commerce Comm'n, 13 Ill. 2d 607, 150 N.E.2d 776 (1958)*, the Illinois Supreme Court highlighted the Commission's discretionary authority to allow a rate recovery for a utility's costs through a purchased-gas adjustment tariff.

(*Ill. Power Co. v. Ill. Commerce Comm'n*, 339 Ill. App. 3d 425, 434 (1st Dist. 2003) (emphasis added)) Automatic adjustment clauses are also known as riders.

Since rider recovery is a discretionary alternative to the traditional approach of setting rates through base rates, an understanding of riders will be enhanced by an understanding of the traditional ratemaking approach. In *Citizens Utilities Co. v. Illinois Commerce Comm'n*, 124 Ill. 2d 195, 200-01 (1988) the Illinois supreme court explained how the Commission typically establishes rates for public utilities:

> In establishing the rates that a public utility is to charge its customers, the Commission bases the determination on the company's operating costs, rate base, and allowed rate of return. A public utility is entitled to recover in its rates certain operating costs. A public utility is also entitled to earn a return on its rate base, or the amount of its invested capital; the return is the product of the allowed rate of return and rate base. The sum of those amounts -- operating costs and return on rate base -- is known as the company's revenue requirement. The components of the ratemaking determination may be expressed in the classic ratemaking formula R (revenue requirement) = C (operating costs) + Ir (invested capital or rate base times rate of return on capital). (*City of Charlottesville, Virginia v. Federal Energy Regulatory Comm'n* (D.C. Cir. 1985), 774 F.2d 1205, 1217, citing T. Morgan, Economic Regulation of Business 219 (1976).) The same formula is used by the Commission in ratemaking determinations for Illinois. The revenue requirement represents the amount the company is permitted to recover from its customers in the rates it charges. Ratemaking is done in the context of a test year, which in this case was 1983.

The revenue requirement formula described in *Citizens* is clearly reflected in the requirement for an operating income statement for the test year under the Standard Information Requirements set forth in Part 285 of the Commission's Rules. (83 Ill. Adm.

Code § 285.3005) Staff similarly presents its proposed adjustments as adjustments to the operating income statement. (*See* ICC Staff Exhibit 13.0, Schedule 13.1 P and N, Statement of Operating Income with Adjustment)[21] Moreover, the Commission utilizes a Statement of Operating Income with Adjustments as an attachment to its orders in general rate cases to reflect its determination of the amount that a utility is permitted to recover from its customers. (*See e.g.*, *In re: Commonwealth Edison Co.*, ICC Docket No. 05-0597, Order, Appendix A (July 26, 2006))

After developing a utility's revenue requirement, the process of developing specific rates to permit a utility to recover its revenue requirement from its customers is generally referred to as the rate design process. The rate design process typically involves the use of a cost of service study to allocate costs among the utility's rate classes, as well as the development of appropriate billing determinants (i.e., number of customers and units of demand) to establish rates that are designed to permit the utility to recover its revenue requirement. As explained by the supreme court, consideration of demand is a critical component of the rate setting process:

> [T]he revenue formula is designed to determine the revenue requirement based on the *aggregate* costs and demand of the utility. … Oftentimes a change in one item of the revenue formula is offset by a corresponding change in another component of the formula. For example, an increase in depreciation expense attributable to a new plant *may* be offset by a decrease in the cost of labor due to increased productivity, or by increased demand for electricity. (Demand for electricity affects the revenue requirement indirectly. The yearly revenue requirement is divided by the expected demand for electricity to arrive at a per kilowatt hour rate. If actual demand is more than the estimated demand used in the formula, the utility's revenues increase.)

[21] As noted above, Appendix A and Appendix B to this brief are updated versions of Staff's Statement of Operating Income with Adjustments for Peoples Gas and North Shore.

(*Business & Professional People for the Public Interest v. Illinois Commerce Comm'n*, 146 Ill. 2d 175, 244-45 (1991) (emphasis in original))

b. General Rider Authority Established

In *City of Chicago v. Illinois Commerce Comm'n*, 13 Ill. 2d 607, 608-609, 614 (1958) – in an appeal from a Commission order approving a rider for Peoples Gas "providing for an automatic adjustment from time to time of its sales price for gas, to reflect changes in the wholesale cost to Peoples of natural gas purchased" -- the Illinois supreme court determined, in a case of first impression, that the Commission was authorized under the Public Utilities Act to approve an automatic adjustment clause in a proper case. The court first considered whether the approval of an automatic adjustment clause exceeded the Commission's statutory power by contravening the requirements in Section 36 of the Public Utilities Act[22] regarding the method and

[22] The court identified the relevant statutory language as follows:

> The governing statutory provisions are contained in section 36 of the Public Utilities Act, (Ill. Rev. Stat. 1957, chap. 111 2/3, par. 36,) which provides the method for any change "in any rate or other charge or classification, or in any rule, regulation, practice or contract relating to or affecting any rate or other charge, classification or service, * * *." The section requires that the utility must file its proposed new schedule with the Commission 30 days before the schedule is to be effective. After the schedule is filed, the Commission shall have the power "either upon complaint or upon its own initiative without complaint, at once, * * * to enter upon a hearing concerning the propriety of such rate or other charge, classification, contract, practice, rule or regulation, and pending the hearing and decision thereon, such rate or other charge, * * * shall not go into effect. * * * All such other rates or other charges, * * * not so suspended shall, on the expiration of thirty days from the time of filing the same with the Commission, or of such lesser time as the Commission may grant, go into effect and be the established and effective rates or other charges, * * * subject to the power of the Commission, after a hearing had on its own motion or upon complaint, as herein provided, to alter or modify the same."

(*City of Chicago*, 13 Ill. 2d at 610). This language was readopted by the legislature in
(continued…)

procedures for changes in rates. (*Id*. at 609-612) Focusing on the broad common and statutory definitions of "rate"[23], the court found that the Commission's authority to approve changes in rates included the power to approve provisions that affect the dollar-and-cents cost of the product sold and was not limited to approving rates stated in terms of dollars and cents. (*Id*. at 611-12) As explained by the court:

> it is clear that the statutory authority to approve rate schedules embraces more than the authority to approve rates fixed in terms of dollars and cents. The present automatic adjustment clause is a set formula by which the price of natural gas to the ultimate consumer is fixed by inserting in the formula the wholesale price of natural gas as established by the FPC. The Public Utilities Act, taken as a whole, contemplates that a rate schedule may contain provisions which will affect the dollar-and-cents cost of the product sold.

(*Id*. at 611)

The court also considered the rationale and holding in *City of Norfolk v. Virginia Electric & Power Co.*, 197 Va. 503, 90 S.E. 2d 140 (1955), because the court there considered similar arguments with respect to virtually identical statutory language. (*Id*. at 612-613) In *Norfolk* the court found that the Virginia Commission was statutorily authorized to approve schedules that affect the rates charged and reasoned that the resulting rates under a formula based adjustment clause "are as firmly fixed as if they were stated in terms of money." (*Id*. at 613) As to the contention that an automatic

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substantially the same form in subsequent enactments, and is currently found in Section 9-201 of the Act. (*See* 220 ILCS 5/9-201)

[23] The statutory definition of "rate" has not changed since *City of Chicago* and is currently found in Section 3-116 of the PUA. (220 ILCS 5/3-116 ("'Rate' includes every individual or joint rate, fare, toll, charge, rental or other compensation of any public utility or any two or more such individual or joint rates, fares, tolls, charges, rental or other compensation of any public utility or any schedule or tariff thereof, and any rule, regulation, charge, practice or contract relating thereto."))

adjustment clause violates the statutory requirement for notice of each increase in the actual rate, the court in *Norfolk* reviewed the relevant statutory language and concluded that "notice is not required on each occasion when there is a change in ratepayers bills but that notice is required for every change in the filed schedules which are the underlying basis for the computation of these bills." (*Id*. at 613) Similarly, the court in *Norfolk* found that due process was not denied since notice of each change in the filed schedules provides an opportunity to be heard as to the justness and reasonableness of the rates charged. (*Id*. at 613-614) The Illinois supreme court found the logic expressed in *Norfolk* to be sound and compelling, and concluded that the Illinois PUA vested "the Commission with power to authorize an automatic adjustment clause to be filed in a rate schedule in the proper case." (*Id*. at 614).

Having found that the Commission had the statutory authority to approve an automatic adjustment clause, the court then proceeded to consider if the Commission abused its discretion to approve such a clause. (*Id*.) Since the Federal Power Commission has exclusive jurisdiction to determine the reasonableness of the rates paid by local distribution companies to gas pipeline companies, the court concluded it was not an abuse of discretion for the Commission to determine that the rates fixed by the Federal Power Commission should be allowed as an operating expense. (*Id*. at 614-616) The court also rejected a claim that the automatic adjustment clause improperly shifted the burden of proof from the utility to consumers because the Commission retained the right to initiate proceedings to investigate any schedule of rates and the burden of proof would be upon the utility in such proceedings. (*Id*. at 616-618)

c. Requirements and Limitations on Rider Recovery

Riders were next considered in *Business & Professional People for Public Interest v. Illinois Commerce Comm'n*, 171 Ill. App. 3d 948 (1st Dist. 1988) ("*BPI*"). In 1977 the legislature amended Section 36 of the PUA to authorize the Commission to implement comprehensive fuel and purchased gas adjustment clauses, including a directive to hold annual hearing to determine if the clauses reflect the actual costs of fuel or power prudently purchased and to reconcile any amounts collected with actual costs. (*Id*. at 953-954) In 1981 the Commission adopted a rule pursuant to Section 36 establishing a Uniform Fuel Adjustment Clause ("UFAC") for electric utilities. (*Id*. at 954) In 1985 the legislature repealed the "old" Public Utilities Act and implemented a new Act, but rewrote Section 36 into the new Act as Section 9-220 with only minor changes. (*Id*. at 955) The appeal in *BPI* arose from an annual reconciliation proceeding for Commonwealth Edison Company ("ComEd") which commenced in 1984 for the costs of fuel and power purchased 1983, and which resulted in a finding that over $70 million of costs should be refunded to customers because they were not prudently incurred. (*Id*. at 955-956)

ComEd argued that the refund order exceeded the Commission's statutory authority because it misinterprets the scope of a rider based prudence review and such an interpretation constitutes retroactive ratemaking. (*Id*. at 956-957) ComEd argued that the Commission erred in looking at plant productivity (i.e., the failure of the LaSalle 1 nuclear power plant to operate at forecasted capacity) to determine the prudence of purchased fuel and power (i.e., fuel and power needed to generate or obtain electricity to replace power not generated due to the reduced productivity of LaSalle 1). (*Id*. at 956-958) The court found ComEd's argument was contrary to the broad grant of authority to the Commission. (*Id*.) Moreover, the court found that ComEd's view on the narrow scope of a rider based prudence review was contrary to the requirement for just and reasonable rates:

> If, in a fuel reconciliation proceeding, the Commission could not examine the reasons that necessitated a fuel purchase, the prudence standard would have no effect on ensuring a just and reasonable rate as required by sections 36 and 41 of the Act; a utility could generate electricity in any manner it chose, efficiently or inefficiently, and the Commission would be limited to determining merely whether the utility paid a prudent price for the fuel.

(*Id*. at 958)

With respect to retroactive ratemaking, ComEd asserted that the refund order violated the rule against retroactive ratemaking enunciated in *Mandel Brothers, Inc. v. Chicago Tunnel Terminal Co.*, 2 Ill. 2d 205 (1954). (*BPI*, 171 Ill. App. 3d at 958) The court explained that in *Mandel* – which involved a traditional rate case that was later overruled by the circuit court -- our supreme court held that once the Commission has determined a rate to be just and reasonable and put it into effect, it could not later determine the rate was excessive. (*Id*.) The court rejected ComEd's retroactive ratemaking argument for the following reasons: (i) the present appeal did not arise from a traditional rate case; (ii) "[t]he reasonableness of a UFAC cannot be determined until after it has been collected"; and (iii) Section 36 explicitly gives the Commission authority to increase or decrease rates through the UFAC "'[notwithstanding] the provisions of this Article.'" (*Id*. at 958-959 (bracketed text in original)) For the foregoing reasons, the court held "that the Commission was within its statutory authority when it applied the prudence standard to the reasons for the purchases, and not only to the actual purchase transactions." (*Id*. at 959)

In *Illinois Bell Tel. Co. v. Illinois Commerce Comm'n*, 203 Ill. App. 3d 424 (2nd Dist. 1990) an appeal was taken from a Commission order approving a modified regulatory plan ("MRP") proposed by Illinois Bell Telephone Company ("Illinois Bell"). The MRP was an attempt to deviate from the traditional manner in which the Commission sets rates by (i) designating a range of acceptable return on equity ("ROE") instead of a single target ROE, (ii) restricting new tariff filings for certain core services so long as earnings did not fall below a baseline of 13% ROE, and providing what was called an incentive plan whereby revenues exceeding a 15% ROE would be shared 50/50 by ratepayers and Illinois Bell via an annual refund mechanism. (*Id*. at 427-428)

In response to arguments that the earnings-sharing provisions of the MRP constituted impermissible retroactive ratemaking, the Commission in *Illinois Bell* argued "that the MRP, like the rate adjustment mechanism in *City of Chicago*, represents a permissible means which may be employed toward the end of setting rates." (*Id*. at 434) The court disagreed, stating as follows:

> Although the MRP does not contemplate that Bell would ever retain any earnings in excess of the 13.79% ROE ceiling, it is clear that the MRP requires Bell to refund to ratepayers earnings which are in excess of the amount which the Commission has determined that Bell should earn. This is tantamount to a determination that the rates which produced these earnings are too high, but the rule against retroactive ratemaking as set forth in [*Business & Professional People for the Public Interest v. Illinois Commerce Comm'n*,, 136 Ill. 2d 192 (1989) (*BPI I*)] prohibits the use of refunds to retroactively reduce rates which are too high. Thus, the refund mechanism of the MRP constitutes impermissible retroactive ratemaking.

(*Id*. at 436) The court also rejected the argument that the refund mechanism of the MRP more closely resembled the set formula upheld in *City of Chicago* rather than the refunds found to exceed the Commission's authority in *BPI I*, noting that there was no utilization of refunds in *City of Chicago*. (*Id*.) The court also went on to find that the

Commission lacked authority under the PUA to implement incentive-based regulation. (*Id*. at 436-439)

In *A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993), the court considered various challenges to a Commission order allowing Commonwealth Edison Company ("Edison") to recover costs associated with demand-side management ("DSM") programs through a rider designated as Rider 22. The court explained that a rider "is a form of tariff that modifies an otherwise applicable standard rate under specific circumstances." (*Id*. at 321-322) IIEC and CUB argued on appeal that Rider 22 violated the prohibition against single-issue ratemaking. (*Id*. at 324) The court reviewed the basis and rationale for the prohibition against single-issue ratemaking, and found that the Commission's approval of Rider 22 violated that prohibition:

> In determining the amount of money a utility is authorized to collect from the consumers, the Commission is required to consider all aspects of the utility's operations during a year selected by the utility as a test year. The test year so selected is intended to be representative of both the utility's anticipated rate-base expenses and its expected revenues, including overall costs and rate of return in the same year. Here, instead of considering costs and earnings in the aggregate, where potential changes in one or more items of expense or revenue may be offset by increases or decreases in other such items, single-issue ratemaking considers those changes in isolation, ignoring the totality of circumstances. Addressing this issue, the supreme court in *Business & Professional People for the Public Interest v. Illinois Commerce Comm'n* (1991), 146 Ill. 2d 175, 244-45, 585 N.E.2d 1032, 166 Ill. Dec. 10 (*BPI II*), stated:
>
> > "The rule against single-issue ratemaking recognizes that the revenue formula is designed to determine the revenue requirement based on the *aggregate* costs and demand of the utility. Therefore, it would be improper to consider changes to components of the revenue requirement in isolation. Often times a change in one item of the revenue formula is offset by a corresponding change in another component of the formula. For example, an increase in

depreciation expense attributable to a new plant *may* be offset by a decrease in the cost of labor due to increased productivity, or by increased demand for electricity. (Demand for electricity affects the revenue requirement indirectly. The yearly revenue requirement is divided by the expected demand for electricity to arrive at a per kilowatt hour rate. If actual demand is more than the estimated demand used in the formula, the utility's revenues increase.) In such a case, the revenue requirement would be over-stated if rates were increased based solely on the higher depreciation expense without first considering changes to other elements of the revenue formula. Conversely the revenue requirement would be understated if rates were reduced based on the higher demand data without considering the effects of higher expenses." (Emphasis in original.)

In the present case, the Commission authorized Edison to charge customers for DSM program costs without considering whether other factors offset the need for additional charges. The order violates the prohibition against single-issue ratemaking. The order thereby isolates one operating expense for full recovery without considering whether changes in other expenses or increased sales and income obviate the need for increased charges to consumers, which may result impermissibly in ratepayers facing additional charges for direct and indirect additional revenues to cover Edison's expenses and pay a return to its investors.

(*Id*. at 325-326)

The court also disagreed with the Commission's argument that applying the prohibition against single-issue ratemaking outside of a general rate case would unduly restrict the Commission and utilities. (*Id*. at 326-327) The court recognized that "[r]iders are useful in alleviating the burden imposed upon a utility in meeting unexpected, volatile or fluctuating expenses," but found that the DSM related expenses at issue were ordinary expenses such as: "payroll for specifically identified planning and similar positions; personnel training, education and travel; contractors and consultants costs; out-of-pocket promotion and computer costs; and conducting workshops." (*Id*.) The court found that the DSM costs at issue "reveal no greater potential for unexpected, volatile or fluctuating expenses which Edison cannot control, than costs incurred in estimating base ratemaking." (*Id*.) Additionally, the court found that a delay in the recovery process and the failure to include such costs in Edison's last rate case did not justify single-issue treatment of costs in a rider. (*Id*.)

IIEC and CUB also argued in *Finkl* that the Commission improperly approved "Rider 22 as an incentive to perform a legally required act." (*Id*. at 327) The court cited to the *Illinois Bell* decision for the proposition that the Commission is without authority to implement directly incentive-based regulation, and found that the Commission's reliance on removing barriers to least cost planning as justification for imposing the rider was an illegal incentive and provided another basis to reverse the Commission's order approving Rider 22. (*Id*. at 327-328)

IIEC and CUB next contended that the Commission's approval of Rider 22 improperly and illegally authorized Edison to charge ratepayers for lost revenues. (*Id*. at 328) The court explained that lost revenues in this context were "revenues that the utility would have earned but for DSM capability building activities." (*Id*.) The court noted that this feature of Rider 22 failed to "take into consideration Edison's aggregate costs and revenues." (*Id*.) The court held that requiring ratepayers to bear the expense of services they avoid due to conservation or DSM programs "runs afoul of basic ratemaking principles," and explained its holding as follows:

> The Act requires that rates be set which "accurately reflect the long-term cost of such services and which are equitable to all citizens." (Ill. Rev. Stat. 1989, ch. 111 2/3, par. 1-102 (now *220 ILCS 5/1-102* (West 1992)) (section 1-102).) Both in *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n (1973), 55 Ill. 2d 461, 483, 303 N.E.2d 364,* and in *Candlewick Lake Utilities Co. v. Illinois Commerce Comm'n (1983), 122 Ill. App. 3d 219, 227, 460 N.E.2d 1190, 77 Ill. Dec. 626,* the courts have asserted that ratepayers are not to pay certain costs unless they directly benefit from them. The lost revenue charge here does not reflect the cost of providing electric service, does not reflect a cost that benefits ratepayers and,

> further, adds to Edison's revenues without regard to whether Edison's demand or revenues increased because of factors unrelated to DSM programs.

(*Id*. at 329)[24]

The court in *Finkl* also agreed with CUB's argument that Rider 22 violated the prohibition against retroactive ratemaking. (*Id*.) However, the court did not provide an explanation of its reasoning other than noting that Rider 22 provides for a review procedure to determine whether expenses were prudently incurred, and citing to *BPI I* for the proposition that "[o]rdering of refunds when rates are too high, and surcharges when rates are too low, violates the rule against retroactive ratemaking." (*Id*.)

The court also agreed with IIEC's argument that Rider 22 violated the Commission's test year rules. (*Id*. at 330-332) The court explained that ratemaking is done in the context of a one year test year, that the test year concept is one promulgated by the Commission in its own rules, and that the "rule has the salutary purpose of preventing the utility from mismatching revenues and expenses. For example, the utility cannot use a low revenue figure from one year and a high expense figure from another year to justify a rate increase." (*Id*. at 330) The court then reviewed the supreme court's opinion in *Business & Professional People for the Public Interest v. Illinois Commerce Comm'n*, 146 Ill. 2d 175 (1991) ("*BPI II*") which held that deferred depreciation and decommissioning expenses could not be recovered in a rate case because those expenses were operating expenses and subject to the Commission's test year rules. (*Id*. at 330-331) The court reasoned that the DSM costs at issue were

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[24] The court also found that the loss revenue recovery feature "vitiates the goal of reducing energy costs by reducing demand" contained in Section 8-402(a) of the PUA. (*Id*. at 329) However, Section 8-402 was repealed by P.A. 90-561, Art. I, § 18, effective December 16, 1997.

properly viewed as "operating expenses", and thus "DSM costs determined outside of a test year cannot be recovered from ratepayers." (*Id*. at 331) The court held that since there was no evidence from which it could determine whether Rider 22 would trigger a total jurisdictional revenue increase of 1% required for application of the test year rule, and since no provision of Rider 22 limited cost recovery in that regard, the test year requirements applied to Rider 22. (*Id*. at 331-332)

In *City of Chicago v. Illinois Commerce Comm'n*, 264 Ill. App. 3d 403 (1st Dist. 1993) the court affirmed a Commission order approving with modification Commonwealth Edison Company's ("ComEd") proposed Rider 28 – Local Government Compliance Costs, which rider provided for recovery of "the marginal costs of providing 'non-standard' service from customers within any governmental unit that mandates such service." (*Id*. at 404) The only issues raised on appeal were (i) whether the Commission's order contained findings and analysis sufficient to allow informed judicial review,(ii) whether the Commission's findings are supported by substantial evidence, and (iii) whether Rider 22 creates unlawful rate discrimination. (*Id*.) The court found that the Commission's order did contain sufficient findings that were supported by substantial evidence. (*Id*. at 409-411) Similarly, with respect to the claim of unlawful rate discrimination, the court found that the City, having failed to submit any evidence before the Commission, failed to meet its burden on appeal. (*Id*. at 411) While the court did not directly consider the appropriateness of Rider 28, the court nevertheless upheld a Commission order approving rider recovery for the marginal costs of providing "'non-standard" service from customers within any governmental unit that mandates such service.

In *Central Ill. Light Co. v. Illinois Commerce Comm'n*, 255 Ill. App. 3d 876 (3rd Dist. 1993) ("*CILCO v. ICC*"), *affirmed in part and reversed in part*, *Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111 (1995) ("*CUB v. ICC*"), the Third District appellate court and Illinois supreme court both upheld the Commission's approval of a rider to recover coal tar clean-up expenditures for costs associated with cleaning up environmental damage resulting from former manufactured gas plant ("MGP") operations.[25] Since the appellate court considered certain issues that were not considered by the supreme court, Staff will review both decisions with respect to approval of a rider cost recovery mechanism.

MGPs operated in Illinois from the mid-1800's to the 1950's. (*CILCO v. ICC* at 879) Coal tar and other byproducts of manufacturing gas were subsequently determined to constitute hazardous wastes, and federal and state laws were passed requiring responsible parties to clean-up contaminated sites. (*Id*. at 879-880) In the 1980's utilities began voluntarily working with state and federal authorities to clean-up the former MGP sites. (*Id*. at 880) The Commission initially considered several utility-specific requests to recover coal tar clean-up costs, and subsequently decided to initiate a generic proceeding to address coal tar issues and the recovery of remediation costs. (*Id*. at 880-881)

Based on evidence presented in the generic proceeding the Commission found that the industry's practices regarding MGPs were reasonable and prudent in light of

[25] The supreme court reversed that part of the appellate court's opinion upholding the Commission's decision to impose sharing of clean-up costs between ratepayers and shareholders by requiring an amortization of such costs without carrying charges, and remanded that portion of the order to the Commission for further proceedings consistent with its opinion. (*See CILCO v. ICC*, 255 Ill. App. 3d at 885-892; *CUB v. ICC*, 166 Ill. 2d at 124-133)

knowledge available at the time, and that as a result a presumption of prudence would apply in future company-specific cases regarding the operation and decommissioning of Illinois MGPs. (*CILCO v. ICC* at 881-882) The Office of Public Counsel ("OPC") and CUB asserted that the Commission's finding as to the prudence of operating and decommissioning MGPs was not supported by substantial evidence and failed to consider company-specific evidence. The court disagreed:

> We find the evidence more than sufficient to support the Commission's finding that in general the MGPs were prudently and reasonably operated and decommissioned. Those operations cannot be judged by today's knowledge of environmental hazards. Viewed in the proper historical context, the evidence supports a presumption that as an industry, MGPs were operated and decommissioned, and wastes disposed of, in a prudent and reasonable manner . . . . It was not necessary that the operation of each MGP plant be reviewed in order to reach a general finding on the standard practices utilized in operating and decommissioning these plants. The Commission has only determined that in future company-specific cases, a rebuttable presumption will be extended to the utility that its operations were reasonable and prudent. The record supports this conclusion.

(*Id*. at 882-883) This determination by the appellate court was not contested before the supreme court. (*CUB v. ICC*, 166 Ill. 2d at 121)

OPC and CUB also contended that the Commission lacked statutory authority to approve rider recovery of coal tar clean-up costs, and further asserted that rider recovery violates the prohibitions against single-issue and retroactive ratemaking as well as the Commission's test year rules. (*CILCO v. ICC*, 255 Ill. App. 3d at 883) The court noted that the Commission determined "that the 'preferred' method for the recovery of remediation costs was through a rider mechanism with a prudency review feature rather than base rates" (*Id*. at 883), and that "a prudency review was an essential feature to ensure that a utility's clean-up activities and costs were necessary and cost-effective." (*Id*. at 884) The court observed that the Commission's authority to approve riders in appropriate situations was recognized by the supreme court in *City of Chicago*. (*Id*. at 884) Declining to "read the *Finkl* opinion in the broad terms asserted by OPC/CUB," the court also rejected the argument that riders violate the prohibitions against single-issue and retroactive ratemaking as well as the Commission's test year rules:

> In Finkl, the First District reversed an order of the Commission which had allowed Commonwealth Edison to utilize a rider to recover costs associated with demand-side management programs. Although the court found the rider in that case to violate both the prohibition against single-issue and retroactive ratemaking, and to contravene the Commission's "test year" requirements, **we do not interpret the opinion as holding that all riders are prohibited**. We note the opinion states with apparent approval that riders are useful in alleviating the burden imposed on utilities in meeting unexpected, volatile or fluctuating expenses. However, in the case before the court, the First District found the demand-side management expenses were not of such a nature as to require rider treatment, and could be readily addressed through traditional base rate proceedings.
>
> Therefore, we read Finkl as holding that the Commission abused its discretion in allowing a rider recovery mechanism under the circumstances because demand-side management costs are not of an unexpected, volatile or fluctuating nature so as to necessitate recovery through a rider. Again, we do not read Finkl as holding that the Commission does not have the authority to allow recovery of costs through riders. Given our view of the Finkl court's holding, we view the opinion's discussion of retroactive ratemaking and test year rules as dicta.
>
> In the instant case, we find no abuse of discretion on the part of the Commission in concluding that coal tar remediation costs can be recovered through a rider mechanism. The record shows these costs will vary widely from year to year depending on the type of remediation activities: from relatively small sums in the thousands (investigation costs) to the millions of dollars (actual cleanup costs). **We view these costs as the type of unexpected, volatile and fluctuating costs which are more efficiently addressed through a rider mechanism.** Therefore, we find the Commission had the authority to authorize a rider as the preferred method of recovery, and that under the circumstances such authorization did not constitute an abuse of discretion.

(*Id*. at 884-885 (emphasis added))

In the subsequent appeal to the supreme court, the court found that CUB waived its retroactive ratemaking and statutory authority arguments by failing to raise them in its petition for rehearing. (*CUB v. ICC*, 166 Ill. 2d at 136) The court then proceeded to address CUB's contentions that the Commission's approval of rider recovery of coal tar clean-up costs constituted impermissible single-issue ratemaking and violated the Commission's test year rules, and rejected both arguments. (*Id*. at 136-140) The court found that the prohibition against single-issue ratemaking applies in the context of a base rate proceeding, and does not constrain the Commission's ability to approve direct recovery of unique costs when rider recovery is warranted:

> In the present case, we are not faced with the Commission's treating a single-expense item within the context of a general rate case. In contrast, a rider mechanism merely facilitates direct recovery of a particular cost, without direct impact on the utility's rate of return. The prohibition against single-issue ratemaking requires that, in a general base rate proceeding, the Commission must examine all elements of the revenue requirement formula to determine the interaction and overall impact any change will have on the utility's revenue requirement, including its return on investment. **The rule does not circumscribe the Commission's ability to approve direct recovery of unique costs through a rider when circumstances warrant such treatment.**

(*Id*. at 137-138 (emphasis added))

The court then considered whether circumstances warrant rider recovery of coal tar clean-up costs, and found that there was no violation of the prohibition against single-issue ratemaking since rider recovery of coal tar clean-up expenses was warranted:

> In *City of Chicago v. Illinois Commerce Comm'n (1958), 13 Ill. 2d 607, 610-11, 150 N.E.2d 776,* this court highlighted **the Commission's discretion in selecting the means by which rates are set and costs are recovered**, and the appropriateness of the rider mechanism **in certain instances**. * * * This court noted that a **rider mechanism is effective and appropriate for cost recovery when a utility is faced with unexpected, volatile, or fluctuating expenses**. In the generic coal-

> tar order at issue in this appeal, the Commission stated that, given the wide variations and the difficulties in forecasting the costs of investigation and remediation activities, riders can generally be expected to provide a more accurate and efficient means of tracking costs and matching such costs with recoveries than would base rate recovery methods. Numerous witnesses testified to the uncertain and variable nature of the expenses for coal-tar clean up. We find that the proposed recovery through a rider mechanism, outside the context of a traditional rate proceeding, does not violate the prohibition against single-issue ratemaking.

(*Id*. at 138-139 (emphasis added))

The court rejected CUB's test year rule argument and found that that rider recovery of coal tar clean-up costs does not violate the Commission's test year rules:

> Ratemaking requires the Commission to consider the revenues and expenses of the utility and frequently requires the use of projections or extrapolations from past data. (*Citizens Utilities Co. v. Illinois Commerce Comm'n* (1988), 124 Ill. 2d 195, 213, 124 Ill. Dec. 529, 529 N.E.2d 510.) To insure accuracy, the Commission has formulated an administrative rule requiring utilities to file rate data in accordance with a proposed one-year test year. (83 Ill. Adm. Code § 285.150 (1985).) The test-year rule is designed to avert mismatching of revenues and expenses that might permit a utility to inaccurately portray a higher need for rate increases. (*Business & Professional People for the Public Interest v. Illinois Commerce Comm'n* (1989), 136 Ill. 2d 192, 219, 144 Ill. Dec. 334, 555 N.E.2d 693.) The Commission argues that the test-year rule is merely a uniform filing requirement which standardizes the information utilities submit to the Commission when applying for base rate increases. The Administrative Code states that the standardized filing requirements are intended "to assist the Commission in performing a thorough and expeditious review of filings for base rate filings." (83 Ill. Adm. Code § 285.110 (1985).) Further, the Administrative Code clearly limits applicability of the filing requirements, including test-year data, to utility company filings that are general rate cases or base rate increases exceeding 1% of jurisdictional revenues. (83 Ill. Adm. Code § 285.130 (1985).) We agree with the Commission and the utilities that the test-year rule seeks to avoid a problem not present when expenses are recovered through a rider. The reconciliation formula used to determine the amount of the rider charge includes a matching of costs incurred with revenue realized. As the Commission notes, the case at bar does not attempt to evaluate or adjust all aspects of the utilities' base rates, and thus the test-year filing is not a prerequisite. We find the Commission's approval of a rider as the preferred mechanism for recovery of coal-tar cleanup costs is within the Commission's authority and not against the manifest weight of the evidence.

(*Id*. at 140)[26]

In *United Cities Gas Co. v. Illinois Commerce Comm'n*, 163 Ill. 2d 1 (1994) the supreme court considered various challenges to a Commission ordered refund of certain gas costs. Like the UFAC for electric utilities discussed above in connection with *BPI*, the Commission has adopted a uniform purchased gas adjustment (""PGA") clause pursuant to its authority under the provisions now codified as Section 9-220 of the PUA. (*Id*. at 4) The Commission's refund order was entered in the context of a PGA reconciliation proceeding. United Cities argued that the refund order constituted retroactive ratemaking contrary to the prohibition discussed in *Citizens Utilities Company v. Illinois Commerce Comm'n*, 124 Ill. 2d 195 (1988). (*Id*. at 12) The court disagreed for several reasons. First, the supreme court found that the Commission's order was entered in a reconciliation proceeding under Section 9-220 of the PUA, which is an exception to the general prohibition against retroactive adjustment of rates. (*Id*. at 14-15) Second, the court held that the Commission's refund order under the PGA rider "did not disturb any of its prior orders or disallow charges or benefits it had previously approved, as did the Commission in *Citizens Utilities* when it ordered a deduction from the base rate of tax benefits it had allowed for 24 prior years. The Commission merely determined that United Cities had failed to sustain its burden of reconciling its revenues

[26] Old Part 285 was repealed and new Part 285 adopted effective August 1, 2003. (27 Ill. Reg. 12251) New Part 285 no longer contains the language limiting the applicability of the standard filing requirements to general rate cases or base rate increases(See e.g., 83 Ill. Admin. Code § 285.130 (2003)), although it does retain the 1% of revenues threshold. (See e.g., 83 Ill. Admin. Code § 285.120 (2003)) Thus, the court's reasoning based on the specific language in old Part 285 limiting the test year filing requirements to base rate filings would no longer apply, but its findings that test-year problems are not present when expenses are recovered through a rider and that approval of a rider for recovery of coal tar costs was within the Commission's authority indicates that that test year rules – like the prohibition against single-issue ratemaking – do not limit the Commission's authority to approve a rider in appropriate circumstances.

with the actual costs of gas prudently purchased for Harrisburg in the year for which the reconciliation was performed." (*Id*. at 15) Thus, the court concluded that the Commission's order did not constitute retroactive ratemaking. (*Id*. at 18)

In *Citizens Util. Bd. v. Illinois Commerce Comm'n*, 275 Ill. App. 3d 329 (1st Dist. 1995) the court reviewed the Commission's approval of Commonwealth Edison Company's ("ComEd") Rate CS (Contract Service), a tariff designed to allow ComEd to retain load that would otherwise leave its system by providing discounted rates to certain commercial and industrial users pursuant to negotiated agreements. (*Id*. at 332) Rather than setting forth criteria or formula by which the discounted rates would be determined, "the tariff merely indicated that revenues from the discounted rates could not be less than the incremental costs of providing service to the customer, thereby ensuring a positive contribution to the utility's fixed cost." (*Id*. at 333) Although the contracts and workpapers deriving the negotiated rates were to be filed with the Commission for informational purposes, both the contracts and supporting work papers would be automatically treated as proprietary and thus would be neither published nor made available for public inspection. (*Id*.)

The court in *Citizens* noted that Section 9-102 of the Act mandates that utilities file with the Commission and keep open for public inspection schedules showing all rates and other charges or classifications for all services provided by it. (*Id*. at 338) The court found that these publication requirements require a utility to "file and publish a schedule of rates and charges, including any contracts which may affect the same." (*Id*.) The court held that ComEd's Rate CS did not comply with these requirements because the actual charges were "not included in the proposed tariff on file with the

Commission nor open to the public for inspection." (*Id*. at 339) Rather, the court found that Rate CS simply granted ComEd "the prospective right to set rates in the future" based on contracts that did not yet exist, and thus did "not comply with section 9-102 of the Act." (*Id*.)

The court in *Citizens* also considered the argument that since Rate CS provided a "'parameter' of possible rates" it satisfied the requirement for a schedule of rates. (*Id*.) The court rejected this argument because Rate CS did "nothing more than limit Edison's otherwise unfettered right to establish any rate it so desires as long as that rate is not below its marginal cost." (*Id*.) The court made clear, however, that it was not holding that the Commission did not have authority to approve a tariff that "truly contains a 'parameter of rates'", such as a rider "containing a mathematical formula under which rates would fluctuate with the wholesale cost of natural gas". (*Id*., pp. 339-340) Nevertheless, the holding in *Citizens* indicates that a rider would be inappropriate if its terms are so broad as to effectively allow the utility to set its own rates.

In *City of Chicago v. Illinois Commerce Comm'n*, 281 Ill. App. 3d 617 (1st Dist. 1996) the City of Chicago ("City") appealed a Commission order directing Commonwealth Edison Company ("ComEd") to remove local franchise fees from base rates for all customers and to localize recovery of those costs by a separate line item charge on the bills of customers residing in the municipality charging the fee. Base rate recovery of franchise fees was resulting in customers outside the City of Chicago paying significantly more -- a net difference of approximately $34 million in 1991 and $33 million in 1992 -- for franchise payments to the City of Chicago than customers within the City of Chicago were paying for franchise fees (in the form of free service) to municipalities outside of the City. (*Id*. at 620) The Commission's decision to remove franchise fees from base rates for rider recovery was intended "to remedy the unreasonable recovery of franchise fees and free and reduced service imposed on Edison by local governmental units …." (*Id*. at 622)

The court first considered the City's argument that the Commission's order constituted rate discrimination since the Commission did not localize property taxes. (*Id*. at 622-627) The court found that the evidence – including the fact that property taxes on generation facilities benefit all customers since the energy so produced is used to serve all customers and not just the customers in the municipality where the plants are located -- supported the Commission's decision to recover franchise fees via a rider and property taxes via bate rates. Specifically, the court found Commission's decision to distinguish franchise fees and property taxes because (i) base rate recovery of franchise fees resulted in the unfair distribution of franchise fee costs – the purpose of which is to allow distribution of electricity to residents in a particular locality -- among customers in different localities and (ii) property taxes generally benefit all customers by facilitating the distribution of power to all customers, adequately supported "the Commission's conclusion that franchise fees are reasonably recovered locally [through a rider] whereas property taxes are reasonably recovered in base rates." (*Id*. at 625-626) Thus, the court concluded that the Commission's decision to allow recovery of franchise fees through a rider and property taxes through base rates "is reasonable and not arbitrary and is supported by substantial evidence." (*Id*. at 626)

The City also argued that the use of a rider for recovering franchise costs violated the prohibition against single-issue ratemaking. (*Id*. at 627) The court noted that “**[t]he Commission has the power to authorize riders in a proper case** and such authorization will not be reversed absent an abuse of discretion.” (*Id*.) The court also explained that “[s]ingle-issue ratemaking is prohibited because it considers changes in isolation, thereby ignoring potentially offsetting considerations and risking understatement or overstatement of the overall revenue requirement.” (*Id*.)

The court first rejected the City’s argument that, pursuant to the court’s decision in *Finkl*, “only unexpected, volatile or fluctuating expenses are properly recovered through a rider:

> *A. Finkl . . .* should not be so narrowly construed. In *A. Finkl*, we stated that "riders are useful in alleviating the burden imposed upon a utility in meeting unexpected, volatile or fluctuating expenses." (Emphasis omitted.) *A. Finkl*, 250 Ill. App. 3d at 327, 620 N.E.2d at 1148. Nothing in the language of *A. Finkl*, or the case upon which we relied, *Citizens Utility Board (sic)*, 13 Ill. 2d at 614, 150 N.E.2d at 780, limits the use of a rider only to those cases where expenses are unexpected, volatile, or fluctuating.

(*Id*. at 628) The court also observed that while the supreme court’s decision in *CUB v. ICC* found that the a rider was appropriate for fluctuating costs, “it did not limit the use of a rider only to those instances where costs are unexpected, volatile or fluctuating.” (*Id*.) Thus, the Commission’s reliance on the unfairness of disparate cost recovery among customers in different localities -- rather than on identification of an unexpected, volatile and fluctuating expense -- as justification for allowing rider recovery of franchise fees was not improper.

While acknowledging that riders must be closely scrutinized because of the danger of single issue ratemaking, the court concluded that the danger of ignoring some items that might have an impact on the overall revenue requirement did not exist under the facts of this case:

> Here, however, that danger was not present. The proposed restructuring was exactly that--a reallocation which did not have any impact whatsoever on Edison's overall revenue requirement. The franchise fees were already included in Edison's overall rate structure; the Commission's order simply redistributed them. Because the rider here "merely facilitates direct recovery of a particular cost, without direct impact on the utility's rate of return" (*Citizens Utility Board*, 166 Ill. 2d at 138, 651 N.E.2d at 1102), it was not an abuse of discretion for the Commission to use it as the mechanism of cost recovery.

(*Id*. at 628-629)

Finally, in *Archer-Daniels-Midland Co. v. Illinois Commerce Comm'n*, 184 Ill. 2d 391 (1998) the supreme court reversed the decision of the Third District appellate court which had reversed an order of the Commission allowing the recovery of contract restructuring costs as costs of fuel under a UFAC rider. The supreme court held that the appellate court erred when it held that the Commission's order resulted in single issue ratemaking because the rule does not apply to the Commission's use of a UFAC rider mechanism outside of a base rate proceeding. (*Id*. at 401-402)

d. Summary of Principles and Standards for Rider Recovery

While the foregoing review of Illinois case law reveals that consideration of a rider recovery mechanism is a multifaceted decision, those cases also disclose that there are a number of fundamental legal principles that must guide the Commission's consideration of any rider proposal. Based on the foregoing review, those principles are as follows:

- The Commission is authorized under the PUA to approve a rider in a proper case. The Commission's authority is not limited to setting rates fixed in terms of dollars and cents, but rather includes the power to adopt a set formula to recover costs in appropriate circumstances. (*City of Chicago v. Illinois Commerce Comm'n*, 13 Ill. 2d 607 (1958))

- Section 9-201 of the PUA requires notice and an opportunity to be heard for changes in filed schedules, but does not require notice of each change in the actual rate under those schedules. The justness and reasonableness of the rates established by a rider are appropriately considered in connection with a review of the filed schedules. (*City of Chicago v. Illinois Commerce Comm'n*, 13 Ill. 2d 607 (1958))

- A rider does not improperly shift the burden of proof provided the Commission does not relinquish its power to initiate proceedings to investigate such rider. (*City of Chicago v. Illinois Commerce Comm'n*, 13 Ill. 2d 607 (1958))

- In order to ensure just and reasonable rates a rider-based prudence review of a particular expense must consider not only whether the amount paid was prudent, but also whether the utility's acts or omissions giving rise to the need for the expense were prudent. (*Business & Professional People for Public Interest v. Illinois Commerce Comm'n*, 171 Ill. App. 3d 948 (1st Dist. 1988) ("*BPI*"))

- The rule against retroactive ratemaking prohibits the Commission from ordering refunds when rates are too high or surcharges when rates are too low for rates it has determined are just and reasonable and put it into effect. An after the fact prudence review under an automatic adjustment clause has been found not to constitute retroactive ratemaking because the reasonableness of the UFAC costs in question could not be determined until after they were incurred and collected. (*Business & Professional People for Public Interest v. Illinois Commerce Comm'n*, 171 Ill. App. 3d 948 (1st Dist. 1988)) Similarly, in *United Cities Gas Co. v. Illinois Commerce Comm'n*, 163 Ill. 2d 1 (1994) the supreme court found that a refund ordered pursuant to a prudence review in a PGA reconciliation proceeding did not constitute retroactive ratemaking because, *inter alia*, such an order does not disallow charges or benefits that the Commission has previously approved.

- The Commission's authority to adopt formula-based rates does not include the power to provide for retroactive adjustments based on earnings since that is tantamount to a determination that the rates which produced such earnings were either too high or too low, contrary to the rule against retroactive ratemaking. (*Illinois Bell Tel. Co. v. Illinois Commerce Comm'n*, 203 Ill. App. 3d 424 (2nd Dist. 1990))

- The Commission has not been given the authority under the PUA to adopt incentive based regulation (*Illinois Bell Tel. Co. v. Illinois Commerce Comm'n*, 203 Ill. App. 3d 424 (2nd Dist. 1990)), and adopting a rider to provide for incentive based regulation is improper. (*A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993))

- The rule against single-issue ratemaking prohibits consideration of changes to components of the revenue requirement in isolation because the revenue formula is designed to determine the revenue requirement based on the aggregate costs and demand of the utility. The rule recognizes that changes in one or more items of expense or revenue may be offset by increases or decreases in other such items. (*A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993)) *In Finkl*, a Commission decision to allow recovery of demand side management ("DSM") costs through a rider was found to violate the prohibition against single-issue ratemaking because it isolated one operating expense for full recovery without considering whether changes in other expenses or increased sales and income obviate the need for increased charges to ratepayers. The *Finkl* opinion also found application of the rule outside of a general rate case was appropriate since the DSM related expenses at issue were not shown to be distinguishable from other operating expenses recovered through base rates, and -- in particular -- revealed no greater potential to be more unexpected, volatile or fluctuating than other base rate expenses. Likewise, a delay in the recovery process without a rider was not found to justify single-issue treatment of costs in a rider. As explained below, the court's determination that rider recovery was not warranted has been found to be the key finding on which its rulings regarding retroactive ratemaking, single-issue ratemaking and the Commission's test year rule depend. Further, the supreme court subsequently held in a different case that "[t]he rule [against single-issue ratemaking] does not circumscribe the Commission's ability to approve direct recovery of unique costs through a rider when circumstances warrant such treatment." (*Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111, 137-138 (1995); see also *Archer-Daniels-Midland Co. v. Illinois Commerce Comm'n*, 184 Ill. 2d 391 (1998))

- A provision for the recovery of lost revenues related to implementation of DSM programs was also found in *Finkl* to violate the prohibition against single-issue ratemaking, as well as other basic ratemaking principles. (*A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993))

- In *A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993), a procedure to review the prudence of costs under a rider was found to violate the prohibition against retroactive ratemaking, which prohibits ordering refunds when rates are too high or surcharges when rates are too low. As explained below, the court's determination that rider recovery was not warranted has been found to be the key finding on which its rulings regarding retroactive ratemaking, single-issue ratemaking and the Commission's test year rule depend.

- Ratemaking is done in the context of a one year test year as required by the Commission's rules. The purpose of the test year rule is to prevent a utility from mismatching revenues and expenses, such as might occur if a utility used a low revenue figure from one year and a high expense figure from another year to justify a rate increase. The supreme court's opinion in *Business & Professional People for the Public Interest v. Illinois Commerce Comm'n*, 146 Ill. 2d 175 (1991) ("*BPI II*") held that non test year operating expenses can not be recovered in a rate case under the Commission's test year rules. In *A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993), a rider providing for the recovery of DSM costs was held to violate the Commission's test year rule where those expenses were determined to be operating expenses. As explained below, the court's determination that rider recovery was not warranted has been found to be the key finding on which its rulings regarding retroactive ratemaking, single-issue ratemaking and the Commission's test year rule depend. Further, the supreme court subsequently held in a different case that test-year problems are not present when expenses are recovered through a rider and that approval of a rider is within the Commission's authority, thus indicating that the test year rule – like the prohibition against single-issue ratemaking – does not limit the Commission's authority to approve direct recovery of unique costs through a rider when circumstances warrant such treatment. (*Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111, 140 (1995))

- In *Central Ill. Light Co. v. Illinois Commerce Comm'n*, 255 Ill. App. 3d 876 (3rd Dist. 1993), *affirmed in part and reversed in part on other grounds*, *Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111 (1995), the court acknowledged that the *Finkl* opinion found the rider in that case to violate the prohibitions against single-issue and retroactive ratemaking as well as the Commission's test year rule, but declined to interpret *Finkl* as holding that all riders are prohibited on those grounds. Rather, the court noted that the Finkl opinion acknowledges that riders are useful in alleviating the burden imposed on utilities in meeting unexpected, volatile or fluctuating expenses, but concluded that the demand-side management expenses were not of such a nature as to require rider treatment. The court read Finkl as holding that the Commission abused its discretion in allowing a rider recovery mechanism in circumstances that did not warrant rider recovery. Thus, the *Finkl* opinion may be read to hold that riders can violate the prohibitions against single-issue and retroactive ratemaking, as well as the Commission's test year rule, in circumstances where rider recovery is not warranted.

- The Commission has discretion to select the means by which rates are set and costs are recovered, and a rider mechanism is effective and appropriate for cost recovery when a utility is faced with unexpected, volatile, or fluctuating expenses. (*Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111, 138-139 (1995))

- A decision to include a prudency review feature in a rider to ensure that clean-up activities and costs were prudent, as well as a decision to apply a rebuttable presumption that utility operation and decommissioning activities were reasonable and prudent, were specifically upheld in *Central Ill. Light Co. v. Illinois Commerce Comm'n*, 255 Ill. App. 3d 876 (3rd Dist. 1993), *affirmed in part and reversed in part on other grounds*, *Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111 (1995) against assertions (i) that the rider violated the prohibitions against single-issue and retroactive ratemaking as well as the Commission's test year rules and (ii) that the rebuttable presumption of prudence was not supported by substantial evidence. Thus, a prudency review feature is within the Commission's authority, and may be necessary to ensure that rider-based rates for the recovery of costs to be incurred prospectively are just and reasonable and recover only prudently incurred costs. Further, the Commission's discretion and authority with respect to prudence determinations is very broad and includes the authority to apply rebuttable presumptions that are supported by substantial evidence.

- While the Commission has authority to approve formula-based rider rates for the recovery of specific costs, the requirement under Section 9-102 of the PUA to file and keep open for public inspection schedules showing all rates and other charges is violated if the terms of a filed schedule are so broad as to effectively allow the utility to set its own rates. (*Citizens Util. Bd. v. Illinois Commerce Comm'n*, 275 Ill. App. 3d 329 (1st Dist. 1995)

- While the courts have evaluated whether rider recovery is justified based on whether the underlying operating expenses to be recovered are sufficiently unexpected, volatile, and fluctuating in character, in *City of Chicago v. Illinois Commerce Comm'n*, 281 Ill. App. 3d 617 (1st Dist. 1996) the court rejected the argument that only unexpected, volatile or fluctuating expenses are properly recovered through a rider. Thus, the Commission's decision to provide for rider recovery of franchise fees to remedy the unfairness to ratepayers resulting from the disparate recovery of such costs among customers in different localities was an appropriate use of its power to authorize rider recovery. While riders must be closely scrutinized for single-issue ratemaking because of the danger of ignoring some items that impact the overall revenue requirement, that danger was not present for a franchise fee rider which provided for the direct recovery of a particular operating expense without any impact on the utility's rate of return.

2. Summary of Staff's Position[27]

While the Commission clearly has the discretionary authority under the PUA to provide for rider recovery of costs **in appropriate circumstances**, the Companies must demonstrate that adequate justification exists for the specific recovery proposed in each rider. As will be explained later in this brief, the Companies have failed to provide appropriate justification for each of the riders.

Rider VBA, Rider WNA and Rider ICR represent significant departures from previously sanctioned riders in that they seek to recover revenue or a return on rate base instead of a particular operating expense that has no impact on earnings under the traditional ratemaking formula. These novel proposals attempt to abandon the traditional ratemaking formula applicable under Illinois law, and as such go too far and must be rejected. Given the unique nature of these proposals, they also present significant problems regarding single-issue ratemaking and the Commission's test year rule, and must be rejected on those bases as well. While Rider UBA and EEP propose the recovery of operating expenses, no appropriate justification is provided for the recovery of those costs through a rider rather than base rates. The underlying costs involved are not sufficiently unexpected, volatile and fluctuating so as to justify rider recovery (*see* ICC Staff Ex.8.0, p. 8, lines 177-183), and the Companies have failed to provide appropriate alternative justifications. Indeed, the Companies' reliance on providing themselves the incentive to promote energy efficiency measures is a

[27] Given the extensive legal analysis presented above and the specific legal arguments provided below, Staff will only provide a brief statement of its legal conclusions in this summary.

justification that has been specifically found to be improper and beyond the Commission's authority, as discussed above.

The Companies' rider proposals also suffer additional legal, factual and policy deficiencies that will be discussed below. In short, the Companies' case fails to establish that rider recovery is appropriate for any of the proposed riders.

If the Companies were able to meet the threshold requirement of demonstrating that one or more of their proposals presented an appropriate justification for rider recovery, the Commission could then consider whether it should exercise its discretionary authority to permit recovery through a rider rather than base rates. The rider cases reviewed above establish the discretionary nature of the Commission's authority to authorize rider recovery, and none of those cases suggest that there is a right to rider recovery. Staff has given careful consideration to the Companies' proposals, and even assuming, *arguendo*, that adequate justification for rider recovery has been shown, there are significant and important reasons for the Commission to decline to permit rider recovery.

The four new riders proposed by Peoples Gas and North Shore are neither reasonable nor necessary. They would restructure the ratemaking process and inappropriately benefit the Companies at the expense of ratepayers and the regulatory process. Therefore, they should be rejected by the Commission.

The Companies state that they are proposing the new riders at this time because of the business challenges they are currently experiencing include "certain volatile and unpredictable circumstances" beyond their control. (Peoples Gas Ex. RAF-1.0, pp. 5-6, lines 101-103; North Shore Ex. RAF-1.0, p. 5, lines 95-97) These challenges include weather variability; declining use per customer; rising and volatile gas prices; rising and volatile customer bills and bad debt expense; energy efficiency and conservation measures; and increasing requirements applicable to infrastructure maintenance and reliability. (Id., Peoples Gas at 6-7, lines 119-130 and North Shore at 5-6, lines 113 – 123)

The primary advocate for the proposed riders is Companies witness Feingold. He asserts that these business challenges have created greater price uncertainty and volatility for customers; and that they have introduced "variability, unpredictability and uncontrollability" into the operations of Peoples Gas and North Shore. (Id., Peoples Gas at 7-9, lines 135-154, 176-182 and North Shore at 6-8, lines 128-148, lines 170-177) The result, he contends, is that each of the Companies faces "ongoing difficulties in recovering its Commission-approved level of costs through base rates." (Peoples Gas Ex. RAF-1.0, pp. 5-6, lines 103-105 and North Shore Ex. RAF-1.0, p. 5, lines 97-99)

Mr. Feingold proposes to address these difficulties by providing for the recovery certain costs and varying revenues through riders. He argues that this proposal is part of an industry-wide trend to employ automatic adjustment mechanisms to recover these costs and revenues. (Id. Peoples Gas at 11, lines 226-228 and North Shore at 10, lines 221-223)

There is a fundamental flaw in Mr. Feingold's argument. The business challenges he finds so threatening have not prevented the Companies from achieving a solid financial performance in recent years under traditional regulation without the benefit of the proposed riders. Not only were the two Companies able to forego filing for a rate increase for the last 12 years, they demonstrated an ability to meet or exceed their authorized rates of returns for several of these years. For example, Peoples Gas met or exceeded its approved rate of return seven out of eight years from 1996 until 2003. Over that same period, North Shore exceeded its authorized return six out of eight years, and as late as 2003 earned a return of 14.13%. This consistent financial success undermines the Companies' claim that the traditional regulatory paradigm is broken and needs to be fixed. (ICC Staff Ex.8.0, p. 6, lines 118-133) In this regard, the arguments of Mr. Feingold and the Companies are misdirected, as it is the legislature that has the authority to change the rate setting process.

The rider-based "fix" for the Companies' problems would present significant issues for ratepayers. If the riders are adopted, the evidence indicates that ratepayers would be exposed to higher bills than under traditional regulation. The evidence for this conclusion comes from the Companies themselves. It indicates that customers would have paid the following additional amounts if Rider VBA had been in effect over the years 2002-2006:

	Peoples Gas	**North Shore**
2002	$43,924,875	$6,045,433
2003	$22,261,021	$1,560,702
2004	$39,568,443	$4,232,381
2005	$50,617,399	$5,634,208
2006	$61,899,211	$6,906,686

(ICC Staff Ex. 8.0, p. 7, lines 151-168)

For Rider UBA, the Companies document the following bill impacts over the same 2002-2006 period:

	Peoples Gas	North Shore
2002	$(4,596,805)	$86,126
2003	$3,441,236	$549,815
2004	$4,105,693	$514,741
2005	$7,439,729	$765,055
2006	$12,440,443	$1,039,956

(ICC Staff Ex. 8.0, pp. 7-8, lines 160-167)

Thus, the collective impact of these two riders if they had previously been adopted ranges from a low in 2003 of $25.7 million for Peoples Gas and $2.1 million for North Shore, to a high in 2006 of $74.3 for Peoples Gas and $7.9 million for North Shore in 2006. The magnitude of these revenue transfers demonstrates how these riders may benefit Peoples Gas and North Shore at ratepayers' expense.

Mr. Feingold seeks to take issue with these figures which were provided by the Companies themselves. He considers them flawed because they reflect "'baseline' revenue per customer levels approved by this Commission in the Companies' last rate cases back in 1995." (North Shore/Peoples Gas Ex. RAF-2.0, p. 46, lines 940-943) Mr. Feingold considers the results in Peoples Gas and North Shore Exhibits RAF-1.5 more relevant because they reflect the Companies' proposed revenue per customer levels for this case as well as existing usage levels. Under these assumptions, customers on average would have received lower annual bills for delivery service under Rider VBA in 2001 and 2003. (North Shore/Peoples Gas Ex. RAF-2.0, pp. 46-47, lines 943-959)

These criticisms lack merit. The purpose of Staff's exercise was to determine the impact on ratepayers during an historical period if Rider VBA was effective at the time. The rates for Peoples Gas and North Shore ratepayers in 2002-2006 were determined in the 1995 cases. For Rider VBA to be effective in 2002-2006, it would have had to be implemented in the 1995 rate case. Because rates are developed on a prospective, not retroactive, basis, Mr. Feingold's proposal to use current test year data to draw conclusions about historical rates is ill conceived. (ICC Staff Ex. 20.0, pp. 15-16, lines 333-341)

Companies witness Feingold seeks to assuage the concerns about ratepayer impacts by arguing that ratepayers will benefit from the symmetrical designs for Riders VBA and UBA. However, his argument is unconvincing. While the possibility exists that the proposed riders could reduce rates, the empirical evidence from the Companies suggests that possibility is not likely to occur. The fact that both Riders VBA and UBA would have consistently raised customer bills if they were in effect for the period 2002-2006 suggests that they will operate to benefit the Companies at ratepayer expense. (ICC Staff Ex. 20.0, p. 17, lines 367-380)

In response to the evidence of financial success over the years 1996-2003, Companies witness Feingold argues that the focus should be on the financial difficulties in the years 2004-2006 to justify the proposed riders. (North Shore/Peoples Gas Ex. RAF-2.0, pp. 10-11, lines 183-204) However, this argument is flawed as well. By 2004, the Companies were approaching their tenth year since their last rate case. If at that time they were earning inadequate returns, they could have filed a new rate case. That is how other gas utilities in Illinois function. When earnings decline, they simply file for a rate increase under the traditional regulatory paradigm without finding the need to add multiple layers of new riders into the mix. The Companies argument that having to file a rate case every twelve years is a sign that traditional regulation is broken and needs to be overhauled is simply nonsensical.

The proposed riders could also burden the regulatory process. Considerable investment of limited Commission resources will be required to oversee rider implementation. If Rider VBA is any indication, oversight could require a considerable investment of Commission and Staff resources. Under Rider VBA, any under- or over-collection of margin revenues is collected on a per-therm basis in customer bills issued two months later. To determine the appropriate per-therm adjustment, a forecast is made of customer usage in that later month. However, there is no guarantee that the forecast and actual usage will be the same. The differences will be reconciled on an annual basis and then amortized over a ten-month period and collected from customers over that time. This process will be undertaken separately for rate classes SC 1N (Residential Non-Heating), 1H (Residential Heating) and 2 (General Service). Furthermore, the entire reconciliation process must be conducted for both Peoples Gas and North Shore. Additional reconciliation processes must be conducted for the five other proposed riders. All these steps could require significant regulatory resources without providing meaningful benefits to ratepayers. (ICC Staff Ex. 20.0, p. 21, lines 458-469)

The experience of overseeing other riders for Peoples Gas and North Shore shows that this responsibility can prove burdensome. The problems that can emerge is illustrated by the oversight of Peoples Gas' and North Shore's Purchased Gas Adjustment ("PGA") clause riders. In Docket Nos. 01-0707 and 01-0706 PGA costs for Peoples Gas and North Shore incurred between October 1, 2000 and September 30, 2001 were examined. A host of problems were encountered and it took more than four years to sort out the issues. The Commission did not issue its final orders on the issues until March 28, 2006. If the seven proposed riders approach the PGA in complexity, they could place a significant burden on the regulatory process. (ICC Staff Ex.8.0, p. 10, lines 211-218)

Adoption of the riders for Peoples Gas and North Shore could also set a precedent for other utilities to request similar rider treatment for their costs and revenues. As a result, the number of riders for the Commission and Staff to oversee could expand even further, leading to an even greater burden on the regulatory process. (ICC Staff Ex. 20.0, p. 21, lines 473-477) This regulatory investment would make sense if ratepayers benefited from the proposed riders. However, when riders are likely to impose additional costs on ratepayers, the resulting regulatory burden becomes that much more difficult to justify. (ICC Staff Ex. 20.0, pp. 21-22, lines 479-486)

Testimony by Companies witness Grace raises additional concerns about the proposed riders. She argues that "Rider VBA is no more complex than the Companies' monthly and annual Rider 2, gas charge and Rider 11, Adjustment for Incremental Costs of Environmental Activities filings." (North Shore/Peoples Gas Ex. VG-2.0, pp. 49-50, lines 1092-1094) Ms. Grace makes the identical argument for Rider UBA. (North Shore/Peoples Gas Ex. VG-2.0, p. 50, lines 1113-1114) The statement that the proposed riders are no more complex than the other referenced riders admits the possibility that Riders VBA and UBA could be as complex as Rider 2, the gas charge for the utilities. Given the problems the Commission has encountered in overseeing the PGA rider for Peoples Gas and North Shore, her statement suggests that the oversight process for Riders VBA and UBA could be difficult and burdensome.

The recent problems encountered by Peoples Gas and North Shore in implementing their PGA riders have important implications for the riders proposed in this proceeding. They raise fundamental questions about the Companies' capability of administering riders, existing or new. The Commission expressed its concern about the Companies' practices in its 2006 Order for the 2001 PGA reconciliation case for Peoples Gas as follows:

> The Commission's finding of imprudence is not the only result of PGL's imprudent and egregious conduct during this reconciliation period. The Commission's confidence in PGL's management to be forthright and fair in serving ratepayer interests and in dealing with the Commission is shaken. The Commission believes that its regulatory compact with PGL, its presumption of good faith on the part of PGL's management, and PGL's overall integrity as a corporate citizen is severely damaged in the instant case.

(Commission Order, Docket No. 01-0707, p. 140, March 28, 2006)

In addition, the Commission put Peoples Gas on notice about future behavior by stating:

> Over the next few years, the Commission intends to closely scrutinize PGL through the audits agreed to in the Settlement Agreement and Addendum (discussed below) in hopes that its conduct during this reconciliation is an aberration.

(Commission Order, Docket No. 01-0707, p. 138, March 28, 2006)

Given these recently expressed sentiments by the Commission, it would be premature to allow Peoples Gas and North Shore to implement seven new riders at this time.

B. Rider VBA and Rider WNA

1. Proposal for Revenue Based Volume Balancing Adjustment Rider

a. Overview of Rider VBA

The Companies propose Rider VBA to address the challenges they are faced with in the current business environment that allegedly hinder recovery of their Commission-approved level of costs. (Peoples Gas Ex. RAF-1.0, pp. 5-6, lines 103-105; North Shore Ex. RAF-1.0. p. 5, lines 97-99) The proposed rider VBA focuses on the so-called "margin revenues" Peoples Gas and North Shore receive from ratepayers for providing natural gas distribution service. According to Companies witness Mr. Feingold, "margin revenues" consist of "a utility's total cost of service, exclusive of purchased gas expenses and any other expenses that are treated as 'flow-through' items in rates (e.g., revenue taxes)." (Peoples Gas Ex. RAF-1.0, p. 15, lines 298-300 and North Shore Ex. RAF-1.0, p. 13, lines 293-295) Mr. Feingold indicates that margin revenues are recovered through both fixed customer charges and volumetric distribution charges. (Id.) Mr. Feingold later defined margin revenues as base revenues, which Staff understands to be the revenue requirement. (Tr. 1372, lines 17-21) The Companies' witness Ms. Grace, defined margin revenues/base revenues as "distribution revenues (margin) approved by the Commission in its most recent rate case proceeding, based on normal weather and the approved level of customers." (North Shore Ex. VG-1.0, pp. 41-42, lines 911-914 and Peoples Gas Ex. VG-1.0, p. 46, lines 1020-1023) While the Companies' terminology had created much confusion, Staff believes that margin revenues basically refers to each Company's revenue requirement which – as noted earlier -- represents the amount the company is to recover from its customers through base rates.

The Companies note that the component of margin revenues recovered through volumetric charges can vary significantly depending on the amount of gas ratepayers consume. A rise in consumption will increase the recovery of margin revenues through variable distribution charges. However, if consumption declines, these margin revenues will decrease and the Companies contend that revenues will fall short of costs. (ICC Staff Ex.8.0, p. 11, lines 231-237)

Rider VBA (Peoples Gas Ex. VG-1.1, pp. 57-60; North Shore Ex. VG-1.1, pp. 55-58) applies only to rate classes SC 1N (Residential Non-Heating), 1H (Residential Heating) and 2 (General Service). Rider VBA purports to implement a monthly adjustment process that "stabilizes the distribution margin approved by the Commission in the Company's most recent rate proceeding." (*Id*. at 57 and 55) While the tariff does not specifically define "distribution margin", it does include the terms Actual Margin and Rate Case Margin, and those terms are defined, respectively, to mean the dollar amount of delivery charge revenues actually billed to each customer class or approved in the Company's most recent rate proceeding.[28] (*Id*. at 57-58 and 55-56) Thus, "margin" under Rider VBA refers to "revenue". Rider VBA specifically excludes revenues from the fixed customer charge, and thus only includes revenues related to volumetric charges. (*Id*.)

[28] While the Commission develops a revenue requirement for each utility as part of the rate setting process in a general rate case, it is the resulting rates – which are included in the filed tariffs -- that are approved rather than a particular level of revenues.

The proposed Rider VBA will adjust ratepayer bills on a monthly basis to ensure that the Companies recover their margin revenues related to volumetric charges. Rider VBA tracks revenue on a per customer basis. The monthly adjustment formula in Rider VBA develops a monthly per customer margin or revenue level for each rate class based on the rates approved in the Company's most recent rate case proceeding. Specifically, the "approved" monthly Rate Case Margin is divided by the number of monthly Rate Case Customers. (*Id*.) An example of these numbers based on the Company's original filing is provided in Peoples Gas Ex. VG-1.17.[29] The Rider VBA formula then requires a similar calculation for each month (called an Effective Month) based on actual revenues and the actual number of customers, and deducts the actual monthly per customer margin from the rate case "approved" per customer margin. The resulting per customer surplus or shortfall is then multiplied by the number of monthly Rate Case Customers to arrive at the total surplus or shortfall for the Effective Month. This amount is divided by the forecasted therms for the Reconciliation Month (the second month after the Effective Month) and multiplied by 100 (to express the adjustment on a cents per therm basis). (*Id*.) The cents per therm adjustment is then billed as a surcharge or a credit in the Reconciliation Month based an actual usage. (*Id*.)

[29] Presumably, the annual margins shown for each rate class in Peoples Gas Ex. VG-1.17, when added with all other rate classes not subject to Rider VBA, equal the total cost of service (i.e., revenue requirement) reflected in the Company's original filing. As best Staff can determine, it is not clear from the record how the amounts and numbers contained in Peoples Gas Ex. VG-1.17 were specifically derived.

b. The Companies' Support of Rider VBA

Companies' witness Feingold presents the Companies' support for a new rider to adjust margin revenues. He claims that the rider "will minimize the impact of weather on Peoples Gas' [and North Shore Gas'] financial condition and on the volatility of its customers' bills." (Peoples Gas Ex. RAF-1.0, p. 21, lines 429-430; North Shore Gas Ex. RAF-1.0, p. 20, lines 429-430) Mr. Feingold also claims it will restore the incentive for Peoples Gas and North Shore to promote energy conservation and efficiency programs for their customers by 'breaking the link' between the Companies' earnings and sales. (Id., Peoples Gas at 22-23, lines 451-472 and North Shore at 21-22, lines 453-475) Furthermore, he maintains that this rider is mutually beneficial because it will have a minimal impact on customers' bills while generating positive results for the Companies. (Id., Peoples Gas at 35, lines 698-700 and North Shore at 32, lines 706-708) Mr. Feingold also claims that customers will still save money under Rider VBA even if weather is warmer than normal and their bills are adjusted upwards (i.e., an increased charge to customer bills from an under-recovery of margin revenues two months prior). (Peoples Gas Ex. RAF-1.0, p. 36, lines 713-721)

Mr. Feingold references the opinions of others to buttress support for the proposed rider. He contends that NARUC recognizes revenue decoupling and notes that nine states have approved revenue-decoupling mechanisms. (Peoples Gas Ex. RAF-1.0, pp. 29-30, lines 575-584) Mr. Feingold further indicates that the financial community welcomes revenue-decoupling mechanisms because of the potential favorable impact on a utility's credit rating. (Peoples Gas Ex. RAF-1.0, pp. 30-31, lines 600-616)

c. Staff's Opposition to Rider VBA

Staff opposes Rider VBA because it violates several legal principles applicable to the development of rates, does not meet the legal burden necessary to warrant special rider treatment, would add additional regulatory overview to an already burdened system, and would unnecessarily supplement the Companies earnings at the expense of the ratepayers, when the Companies already have ample opportunity to achieve their authorized rate of return. The Commission should therefore reject Rider VBA.

(1) Rider Recovery of Revenue Shortfalls and Surpluses Under Rider VBA Is Contrary to Several Ratemaking Principles

Rider VBA is fundamentally different from any other rider which the Commission has authorized and the courts have upheld. Rather than provide for the recovery a particular operating expense, Rider VBA seeks to guaranty revenue levels and earnings. As explained above, Rider VBA takes the revenues that the rates approved in a base rate proceeding were intended to recover (which includes the Company's authorized return on rate base), and provides a surcharge if those rates produced insufficient revenues or a credit if those rates produced surplus revenues. This is clearly contrary to the rule against retroactive ratemaking.

It is well established that the PUA does not permit retroactive ratemaking and thus "prohibits refunds when rates are too high and surcharges when rates are too low." (*Business & Professional People for the Public Interest v. Illinois Commerce Comm'n*,, 136 Ill. 2d 192, 209 (1989)) Thus, once the Commission has determined a rate to be just and reasonable and put it into effect, it can not later determine the rate was excessive. (*Business & Professional People for Public Interest v. Illinois Commerce*

Comm'n, 171 Ill. App. 3d 948, 958 (1st Dist. 1988)) The Commission's authority to adopt formula-based rates does not include the power to provide for retroactive adjustments based on earnings. (*Illinois Bell Tel. Co. v. Illinois Commerce Comm'n*, 203 Ill. App. 3d 424, 436 (2nd Dist. 1990)) As explained by the court:

> [I]t is clear that the MRP requires Bell to refund to ratepayers earnings which are in excess of the amount which the Commission has determined that Bell should earn. This is tantamount to a determination that the rates which produced these earnings are too high, but the rule against retroactive ratemaking as set forth in [*Business & Professional People for the Public Interest v. Illinois Commerce Comm'n*,, 136 Ill. 2d 192 (1989) (*BPI I*)] prohibits the use of refunds to retroactively reduce rates which are too high. Thus, the refund mechanism of the MRP constitutes impermissible retroactive ratemaking.

(*Id*.)

Like the modified regulatory plan in Illinois Bell, the refund and surcharge provisions of Rider VBA constitute impermissible retroactive ratemaking. Rider VBA guarantees recovery of the Company's revenue requirement for the subject rate classes, and thus guarantees recovery of the rate of return embedded in that revenue requirement. Moreover, the mechanism under Rider VBA is designed to provide refunds or surcharges based on an assessment of whether the rates approved by the Commission turned out to be too low or too high.

The cases upholding riders against retroactive ratemaking challenges are clearly distinguishable from the instant rider proposal. (See e.g., *Central Ill. Light Co. v. Illinois Commerce Comm'n*, 255 Ill. App. 3d 876 (3rd Dist. 1993), *affirmed in part and reversed in part on other grounds*, *Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111 (1995); *Business & Professional People for Public Interest v. Illinois Commerce Comm'n*, 171 Ill. App. 3d 948 (1st Dist. 1988)) In each case where a rider has been upheld against a claim of retroactive ratemaking, the rider has provided for the recovery of a specific operating expense which was removed or excluded from the utility's base rates. Here, in contrast, Rider VBA provides for the recovery of revenues "approved" for recovery is a base rate proceeding. It is difficult to conceive of a more direct violation of the rule against retroactive ratemaking.

Not only does Rider VBA violate the prohibition against retroactive ratemaking, but it also proposes to retroactively adjust rates in a manner that would result in rates that are not just and reasonable. As explained above, Rider VBA seeks to ensure recovery of 100% of its revenue requirement related to its volumetric charges irrespective of any actual reduction in demand. While the volumetric charges are designed to recover some costs that are fixed, they also recover variable costs. According to Ms. Grace, about 5% of Peoples Gas' costs and 1% of North Shore's costs vary with throughput. (North Shore Ex. VG-1.0 REV, p. 6; Peoples Gas Ex. VG-1.0 2REV, p. 8) While these percentages are not high, the fact remains that Rider VBA absolutely fails to take into account these variable costs and provides for recovery of costs that are not incurred in customers reduce demand.

Rider VBA also violates the prohibition against single-issue ratemaking. The rule against single-issue ratemaking is based on the principle that the Commission sets rates based on aggregate costs and demands As explained by the supreme court in *Business & Professional People for the Public Interest v. Illinois Commerce Comm'n*, 146 Ill. 2d 175, 244-45 (1991), the rule would be violated by consideration of changes in demand without considering changes in expenses, and vice versa:

> (Demand for electricity affects the revenue requirement indirectly. The yearly revenue requirement is divided by the expected demand for electricity to arrive at a per kilowatt hour rate. If actual demand is more than the estimated demand used in the formula, the utility's revenues

> increase.) In such a case, the revenue requirement would be over-stated if rates were increased based solely on the higher depreciation expense without first considering changes to other elements of the revenue formula. Conversely the revenue requirement would be understated **if rates were reduced based on the higher demand data without considering the effects of higher expenses**.

(*Id*. (emphasis added))

Rider VBA commits to a tariff the very evil that the prohibition against single-issue ratemaking is intended to avoid – adjusting rates based on a one component of the revenue requirement formula, i.e., revenue based on demand. The opinions sustaining the approval of a rider against single-issue ratemaking challenges provide no cover to Rider VBA. In upholding the Commission's decision to permit rider recovery of coal tar clean-up costs in *Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111 (1995), our supreme court held that "[t]he rule [against single-issue ratemaking] does not circumscribe the Commission's ability to approve direct recovery **of unique costs** through a rider when circumstances warrant such treatment." (*Id*. at 137-138 (emphasis added)) Rider VBA provides for the recovery of revenue rather than a particular operating expense, and thus does not fit within the exception recognized by the court.

As noted above and discussed in more detail below, the Company also posits that Rider VBA is needed to give it the proper incentives to implement energy efficiency measures. The Commission has not been given the authority under the PUA to adopt incentive based regulation (*Illinois Bell Tel. Co. v. Illinois Commerce Comm'n*, 203 Ill. App. 3d 424 (2nd Dist. 1990)), and adopting a rider to provide for incentive based regulation is improper. (*A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993))

As noted earlier, Illinois courts have held a rider mechanism is effective and appropriate for cost recovery when a utility is faced with unexpected, volatile, and fluctuating expenses. (*Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111, 138-139 (1995)) While the Companies mention the "unexpected, volatile, and fluctuating" buzzwords in their support of Rider VBA, it is not in the context of an expense since Rider VBA seeks recovery of revenues. The everyday business challenges faced by a utility are not the type of special circumstances that justify rider recovery. Moreover, as explained in more detail below, the logic and basic put forth for Rider VBA is difficient.

(2) The Companies arguments in support of Rider VBA are flawed.

First, Mr. Feingold's claim that the proposed rider will reduce the volatility of ratepayer bills is not necessarily true. In fact, Rider VBA could actually increase the volatility of bills. The proposed Rider VBA adjusts margin revenues for an individual month, two months afterwards. (Peoples Gas Ex. VG-1.0, p. 47, lines 1038-1041 and North Shore Ex. VG-1.0, p. 42, lines 929-932) For example, the under- or over-collection of margin revenues in December would be adjusted on February bills. If margin revenues in December fall below the target level, then February bills would be adjusted upwards to recover the shortfall. However, if cold weather in February drives usage and customer bills above average, the February bill increase will be exacerbated by the upward Rider VBA adjustment to recover December's shortfall in margin revenues. In this instance, Rider VBA would exacerbate the upward spike in February customer bills. (ICC Staff Ex.8.0, pp. 12-13, lines 267-281)

Mr. Feingold's argument about reduced volatility would be accurate if margin revenues each winter are consistently above or below normal. Then, the adjustment process would bring monthly bills closer to the average. However, a shorter-term variation in margin revenues could increase the volatility of ratepayer bills under Rider VBA as the previous example shows. (ICC Staff Ex.8.0, p. 13, lines 283-287)

Moreover, the Companies have proposed other methods and surcharges that Rider VBA does not take into account, which will also profoundly impact customer bills. First, the Companies proposed to change from a 30-year to a 10-year weather normalization period (Peoples Gas Ex. LTB-1.0, p. 10, lines 206-224 and North Shore Ex. LTB-1.0, p. 14, lines 294-303) This proposal for a shorter normalization period, which Staff does not contest, will address the Companies' concern that the decrease in gas delivered and sold to customers is in part due to a warming trend in weather. (Peoples Gas Ex. RAF-1.0, pp. 17-19)

The second proposal is to increase the levels of fixed, customer charges collected from ratepayers. For residential customers, Peoples proposes increases from the current $9.00 to $11.25 and $19.00 for non-space heating and space heating customers, respectively. (Peoples Ex. VG-1.4, p. 1 of 12) The corresponding charges for North Shore would increase from the current $8.50 to $10.50 and $16.50 for non-space heating and space heating customers, respectively. (North Shore Ex. VG-1.3, p. 1 of 2) Increases in these charges would reduce the level of revenues recovered by variable charges and thereby stabilize the Companies' revenue stream.

Both proposals will cause a reduction in revenue variability that undermines the Companies' justification for a need to establish an extraordinary measure, such as Rider

VBA, to also stabilize revenues. (ICC Staff Ex.8.0, p. 13, lines 289-299) Mr. Feingold presents a half-hearted response to this argument. First, he insists that the Companies' weather normalization and customer charge proposals do not "undermine" their Rider VBA proposal. He then concedes that these proposals "partially address" the issues of volatility and margin revenue shortfalls, but insists that they are insufficient to obviate the need for Rider VBA because they do not eliminate the problem. (North Shore/Peoples Gas Ex. RAF-2.0, pp. 18, lines 348-355)

Mr. Feingold's arguments are problematic. First, he fails to consider in any meaningful way the effect of the weather normalization and customer charge proposals on volatility and margin revenues. He does not quantify the effects or his assumed shortfalls. Moreover, Mr. Feingold readily admits that all volatility and revenue shortfalls must be eliminated. Yet, Staff has demonstrated that bill volatility is not eliminated by the implementation of Rider VBA.

Mr. Feingold's second argument speculates that Rider VBA will restore the incentive for Peoples Gas and North Shore to promote energy conservation and efficiency programs if the volume of gas delivered is no longer linked to the Companies' revenues. There are several fundamental flaws in the Companies' argument. Usage data for the last 12 years indicates that ratepayers do not require assistance from Peoples Gas and North Shore to conserve gas. They have already taken extraordinary steps to reduce their consumption. Companies' witness Borgard documents a steep decline in natural gas throughput on the Peoples Gas system over recent years. He notes that throughput on the Peoples Gas system fell from the 1996 level of 235.7 bcf projected in the Company's 1995 rate case down to a 2006 normalized level of 177.6

bcf. According to Mr. Borgard, this represents a reduction of 58 bcf or 25% over the 10-year period. (Id. Peoples Gas at 10, lines 208-213) Mr. Borgard indicated that average annual use by residential heating customers declined by 29% from 160 to 113 dekatherms over the last decade (Id. Peoples Gas at 16, line 353) and small residential heating customer use for North Shore declined by 16% from 159 to 133 dekatherms over the same 10-year period. (Id. North Shore at 14-15, lines 313-315)

The evidence demonstrates that ratepayers are highly motivated to conserve and do not require any additional assistance from the Companies to reduce consumption. They certainly do not need a transformation in the regulatory paradigm to provide the Companies with incentives to facilitate their conservation efforts. (ICC Staff Ex.8.0, pp. 15-16, lines 339-352)

Furthermore, Peoples Gas and North Shore have failed to demonstrate that with the proper incentives they can play an effective role in motivating ratepayers to conserve. The current incentive for Peoples Gas and North Shore is to encourage more usage by ratepayers. As Mr. Feingold acknowledges, "[t]he "Throughput Incentive" encourages a utility such as Peoples Gas to be financially motivated to increase sales of natural gas (relative to historical levels which underlie base rates) and to maximize the "throughput" of natural gas across its utility system." (Peoples Gas Ex. RAF-1.0, p. 23, lines 455-458 and North Shore Ex. RAF-1.0, p. 21, lines 457-460) Despite this incentive, the Companies could not prevent ratepayers from significantly reducing their gas consumption over the past twelve years. If Peoples Gas and North Shore were unable to induce ratepayers to consume more before, it is not clear why they will be able to motivate ratepayers to use less in the future. (ICC Staff Ex.8.0, p. 16, lines 366-368)

If the Companies were truly interested in promoting conservation by their customers they would have proposed a rate design that motivates ratepayers to conserve by recovering a larger share of costs through usage charges, rather than fixed customer charges. Instead, they have proposed large increases in customer charges, which consumers pay regardless of their usage levels. If anything, the Companies are motivating their customers to become apathetic about the amount of gas they consume, as they will be charged the same price irrespective of their conservation efforts. (ICC Staff Ex. 20.0, p. 8, lines 156-167)

Third and also deficient is Mr. Feingold's argument that Rider VBA will have a minimal impact on customers' bills but a significantly positive effect on the Companies. He supports his argument with selective analyses of ratepayer impacts that fail to indicate whether the proposed rider will increase or decrease ratepayer bills on an overall basis. This omission is understandable considering that the Companies provided evidence in the discovery process, which indicates that ratepayer bills could increase substantially under the proposed riders. The additional annual cost to ratepayers assuming Rider VBA was effective between 2002 and 2006 range from a low of $22.3 ($1.6) million to a high of $61.9 ($6.9) million for Peoples Gas (North Shore). (ICC Staff Ex.8.0, pp. 17-18, lines 389-395)

Fourth, Mr. Feingold's reference to the "authorized level of margin revenues" for the Companies is irrelevant in the current regulatory environment. Margin revenue has no meaning as a standard for assessing the financial performance of Peoples Gas and

North Shore in the Illinois regulatory process. The better and broader measure employed by the Commission concerns the rate of return achieved by the Companies on their investments. Moreover, by that measure the Companies have prospered in recent years. If margin revenues under Rider VBA are added to the mix, it could raise those healthy returns even further based on the evidence provided by Peoples Gas and North Shore. (ICC Staff Ex. 8.0, p. 7, lines 151-168) Thus, Peoples Gas and North Shore could enjoy extraordinary returns at ratepayer expense.

Fifth, Mr. Feingold's claim that even when customer bills are increased because the temperature is warmer than normal the customers will still see savings, assumes that customers would not save money when it is warmer than normal without Rider VBA. Mr. Feingold's argument only works in a vacuum. Mr. Feingold acknowledges that if the weather is warmer than normal, then customers will pay more to make up the difference for the reduced amount of gas used because of the warmer conditions. (Peoples Gas Ex. RAF-1.0, p. 36, lines 717-721 and North Shore Ex. RAF-1.0, p. 33, lines 725-730) Mr. Feingold concludes this is so because when it is warmer customers use less gas, and since there is more gas available, the cost of gas is cheaper. (Id.) However, customers would save money when it is warmer than normal anyway, for the exact reasons that Mr. Feingold cites, consumption is down, and gas prices are down. In reality, if it is warmer than normal, while bills would be lower than they would "normally" be, Rider VBA increases the rate customers pay to make up for that difference.. (ICC Staff Ex.8.0, pp. 20-21, lines 461-471)

In rebuttal testimony, Mr. Feingold tries to clarify his statement, but only restates it in a vaguer manner. He states that "[e]ven when the unit cost of delivery service must be adjusted upward through Rider VBA due to warmer than normal weather, this adjustment will not detract from customers' ability to experience reduced gas bills as they would currently." (North Shore/Peoples Gas Ex. RAF-2.0, p. 55, lines 1120-1123) Yet, Rider VBA is specifically designed to make up for the lost volumetric revenue tied to consumption. Thus to accept Mr. Feingold's argument, the Commission must separate the customer bill into the Rider VBA increase, and the gas cost and delivery portion savings. Then the Commission must assume that with this imaginary line drawn, customers will still see a savings on the gas cost and delivery portion of their bill in warmer than normal weather, and not count against it, any Rider VBA increase.

Sixth, Mr. Feingold's effort to weave outside opinions into the argument for revenue decoupling in Illinois is inconclusive and built on selective evidence. The opinions referenced by Mr. Feingold includes a statement by NARUC that revenue decoupling "provides earnings stability and removes the disincentives for promoting energy conservation" (Id. Peoples Gas at 27, lines 541-544 and North Shore at 25, lines 546-549) as well as a call for realigning utility incentives to promote conservation in the recently issued "National Action Plan for Energy Efficiency." (Peoples Gas Ex. RAF-1.0, p. 29, lines 566-570 and North Shore Ex. RAF-1.0, p. 26, lines 571-575) He also notes that nine states have approved revenue decoupling for sixteen utilities, with eleven more proposed and pending approval by regulatory bodies. (Id. Peoples Gas at 30, lines 588-599 and North Shore at 27-28, lines 594-606)

That NARUC has acknowledged the function of revenue decoupling mechanisms does not translate into support for the adoption of these mechanisms by all state regulatory Commissions. Indeed, as Mr. Feingold's own testimony states, NARUC's position is to encourage State Commissions "to review the rate designs they have previously approved to determine whether they should be reconsidered…." (Id. Peoples Gas at 28, lines 551-553 and North Shore at 25, lines 556-558) Furthermore, it should be remembered that even if NARUC were to declare its support of revenue decoupling, that would not mandate the Commission to act. (ICC Staff Ex.8.0, pp. 19-20, lines 441-443)

As for activity in other jurisdictions, approval by regulators in ten states does not demonstrate overwhelming regulatory support for revenue decoupling. Mr. Feingold's numbers would indicate that four out of five regulatory bodies have failed to adopt revenue decoupling. (ICC Staff Ex.8.0, p. 20, lines 445-447) Moreover, among the states that have approved such mechanisms, several have only approved pilot programs, or limited and modified revenue-decoupling programs. Several other states are acting under statutory direction to investigate revenue-decoupling mechanisms as an alternative to traditional statutorily approved ratemaking. It is therefore evident by the lack of approvals and abundant reservations that state public utility commissions have not embraced revenue-decoupling mechanisms.

In fact, few states, if any, have approved an unlimited revenue-decoupling program, as the Companies are requesting in this proceeding. Most states have placed temporal and monetary limits to allow for investigation, and to protect ratepayers. Specifically, many states are concerned about the shifting of risk onto the ratepayers. For example, in his rebuttal testimony, Mr. Feingold cites Colorado as recently approving a revenue-decoupling program. (North Shore/ Peoples Gas Ex. Raf-2.0, p. 38, line 778 and Ex. 2.3) However, Mr. Feingold refuses to discuss that the Colorado

Public Utilities Commission only approved a revenue-decoupling program as a pilot program, with severe revenue collecting limitations fearing the risk a revenue decoupling mechanism places on ratepayers. (Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado for Advice Letter No. 690-GAS, Decision No. C07-0568; Docket No. 06S-656G, 2007 Colo. PUC LEXIS 535, 31-32, 258 P.U.R.4th 185, (June 18, 2007))

The Colorado Commission found a shift of risk to the utility's customers when revenue decoupling mechanisms are implemented, and therefore, adjusted the revenue decoupling mechanism to "divide the risk between ratepayers and [the] Public Service [Company of Colorado]." (Id. at 32)

The Connecticut Department of Public Utility Control also found that revenue-decoupling mechanisms shift risk onto the ratepayers, and therefore approved a revenue decoupling mechanism that divided the risk between the ratepayers and the utility. (DPUC Investigation into Decoupling Energy Distribution Company Earnings from Sales, Docket No. 05-09-09, 2006 Conn. PUC LEXIS 91, 32; 247 P.U.R.4th 387, (January 18, 2006)) Moreover, the Connecticut DPUC found that revenue decoupling does not by itself provide an incentive to utilities to promote conservation. (Id. at 1-2) In addition, in addressing revenue decoupling, Connecticut was acting under state legislative mandates. (Id. at 1)

In 2006, the Utah Public Service Commission adopted a stipulated agreement between the utility and intervenors for a three year pilot revenue-decoupling program. (In the Matter of the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders, Docket No. 05-057-T01, 2006 Utah PUC LEXIS 261, 9, (October 5, 2006)) The stipulation was the result of a need to implement a demand side management program. (Id. at 2) In reaching a settlement, the parties agreed that the utility would take a $1.1 million rate reduction, initiate a DSM program and a revenue-decoupling program. (Id. at 11) The revenue-decoupling program however would be limited to three years, with a review in the first year that would allow the parties to propose alternative programs. (Id.) The stipulation also capped the program to 1% of the utility's rate revenue for the effected rate class. (Id. at 10) Even with a three-year limit, the revenue-decoupling program would be reviewed after its first year.

Other states have concluded that utilities are doing well enough with out revenue decoupling, and decoupling is not an incentive for utilities to promote conservation or for customer to conserve. In 2006, Arizona rejected a revenue-decoupling proposal, citing many of the same concerns that Staff and the Intervenors have so far expressed in the instant proceeding:

> There is conflicting evidence in the record as to whether the recent level of declining per customer usage will continue into the foreseeable future, and whether conservation efforts are the direct cause of Southwest Gas' inability to earn its authorized return from such customers. Further, as RUCO points out, the likely effect of adopting the proposed CMT is that residential customers will be required to pay for gas that they have not used in prior years, a phenomenon that could result in disincentives for such customers to undertake conservation efforts. (Rate Increase, Southwest Gas Corporation, Docket No. G-01551A-04-0876; Decision No. 68487, 2006 Ariz. PUC LEXIS 22, 65-66; 247 P.U.R.4th 243 (February 23, 2006))

The Indiana Utilities Commission approved of a revenue decoupling mechanism with several "safeguards": 1) a margin recovery cap; 2) an Oversight Board; and 3) an earnings test to "ensure that rate decoupling does not result in excess earnings." (Verified Petition of Indiana Gas Company, Inc. and Southern Indiana Gas and Electric Company D/B/A Vectren Energy Delivery of Indiana, Inc. for Approval of a Conservation

Program and a Conservation Adjustment through Approval of New Tariff Riders and Associated Terms and Conditions of Service, Cause No. 42943, Cause No. 43046, 2006 Ind. PUC LEXIS 376, 141-143 (December 1, 2006)) The Idaho Public Utilities Commission also approved a revenue decoupling mechanism with added safeguards and oversight. (In the Matter of the Investigation of Financial Disincentives to Investment in Energy Efficiency by Idaho Power Company, Case No. IPC-E-04-15; Order No. 30267, 2007 Ida. PUC LEXIS 44, 7; 256 P.U.R.4th 322 (March 12, 2007)) The Idaho Commission only approved the program for 3 years, with the caveat that the Commission Staff could request the Commission to discontinue to program with proper justification. (Id.)

In Delaware, as Mr. Feingold notes on North Shore/Peoples Gas Ex. 2.3, two utilities proposed revenue-decoupling mechanisms in a generic proceeding. Missing from Mr. Feingold's chart is the fact that the Delaware utilities attempted to propose revenue-decoupling mechanisms in a rate case, but agreed to withdraw them, so that the Commission could open a generic proceeding to investigate revenue decoupling. (In the Matter of Delmarva Power & Light Company for change in Natural Gas Rates, PSC DOCKET NO. 06-284; ORDER NO. 7152, 2007 Del. PSC LEXIS 46, 13 (March 20, 2007)) (*See also* In the Matter of the Investigation into Revenue Decoupling Mechanisms, Docket No. 59; Order No. 7153, 2007 Del. PSC LEXIS 47 (March 20, 2007))

Lastly, the Virginia legislature enacted legislation mandating the investigation of revenue decoupling (30 V.S.A § 218d(a)(4)), providing evidence that the legislature saw fit to amend the rules of traditional ratemaking that pubic utility commissions are bound to.

States that have approved decoupling mechanisms have done so with great apprehension, after thorough investigation and testing, and often at the behest of the legislature. These states have adopted revenue decoupling mechanisms, but either as pilot program, with safeguards, or both. In contrast, the instant Rider VBA does not have, nor have the Companies proposed, any safeguards to protect the ratepayers. The instant Rider also does not allow the Commission to review the effectiveness of the Rider before the Companies choose to file for another rate case, and there is no expiration or test period to evaluate the effects of Rider VBA.

Seventh, Mr. Feingold's argument that the financial community recognizes the value of revenue decoupling mechanisms such as Rider VBA is also unpersuasive. He quotes a statement by Moody's Investor Service that such proposals "would serve to stabilize the utility's credit metrics and credit ratings." (Peoples Gas Ex. RAF-1.0, p. 31, lines 612-615 and North Shore Ex. RAF-1.0, p. 29, lines 619-622) This result is expected considering that Rider VBA should generate higher retail revenues for Peoples Gas and North Shore. Thus, the stabilization of credit for Peoples Gas and North Shore could come at the expense of higher bills for Peoples Gas and North Shore ratepayers. (ICC Staff Ex.8.0, p. 20, lines 449-459)

In addition, Rider VBA is being proposed to address a problem that does not exist. The financial distress the Companies claim has simply not been established. The available evidence indicates that Peoples Gas and North Shore have achieved sustained success in recent years despite the business challenges. For example, as

Company witness Feingold acknowledges, the cost of service consists of two components, expenses and a rate of return on rate base. (Tr. 1350, line 22-1351, line 4) Therefore, if after paying its expenses, the utility realizes its approved rate of return, then the utility is, by definition, recovering its cost of service. Peoples Gas and North Shore have consistently met or exceeded their approved rates of return and recovered the cost of service for a full decade after their last rate case in 1995. Furthermore, the Companies did not file another rate case for another dozen years. Companies' witness Feingold is unable to identify any other gas utility in Illinois that has stayed away from the rate case process for so long in recent years. (Tr. p. 1368, line 22 – 1369, line 3)

In the face of this clear and straightforward evidence of financial health, Companies' witness Feingold searches for evidence to support an alternative conclusion—he expresses concern about a shortfall in the Companies' "margin revenues." Even though the Companies have consistently achieved their authorized rates of return, Mr. Feingold argues they are entitled to relief (and even higher returns) because their margin revenues have fallen short.

To support his proposal, Mr. Feingold revises the metrics on which the utility's financial metrics are defined. His new definition is that "[t]he utility's financial health is directly tied to its ability to recover the actual cost of service (excluding purchased gas costs) approved by the regulator through the margin revenues upon which its base rates were previously established." (Peoples Gas Ex. RAF-1.0, p. 16, lines 315-317)

This focus on margin revenues is a fundamental shift from longstanding Commission precedent. In the past, a utility's financial health was based on its ability to earn its approved rate of return, which is based on the difference between its revenues and costs. As long as the return is being realized, it does not matter whether a target level of revenues is being met. If the Commission were to change course and focus on both returns and margin revenues that would create a clear opportunity for over-earning.

The evidence clearly indicates that in the past, Rider VBA would have produced over-earnings by increasing revenues when Peoples Gas and North Shore were already earning their authorized rates of return. Mr. Feingold's Exhibit 1.4 indicates that between 1997 and 2006 the volumetric impact on margin revenues for both Peoples Gas and North Shore was negative in nine out of ten years. If Rider VBA had been in effect during this time, the Companies would have received upward margin revenue adjustments in each of those nine years. All the while, the return on equity for both Peoples Gas and North Shore exceeded their authorized levels in six of those years. Therefore, if Rider VBA had been in effect during that time, Peoples Gas and North Shore would have benefited from both a return on equity above their authorized levels plus an upward adjustment in margin revenues in six out of ten years. (ICC Staff Ex. 20.0, pp. 3-4, lines 61-73)

Mr. Feingold's proposal to introduce margin revenues into the cost of service equation is inconsistent with his admission under cross-examination that the cost of service consists of two components, expenses and a rate of return on rate base. (Tr. 1350, line 22-1351, line 4) Mr. Feingold's confusion between costs and revenues becomes evident in the following "clarification" of the term:

> Now, by the same token, I, myself, have used "base rate revenues" and "base revenues" in the past. So I'm not as hung up on the term "margin" as long as we're capturing the fact that we're talking about the non-gas cost of service and we're talking about the costs associated with

> supporting the companies providing customers with delivery service. (Tr. 1392, lines 11-18)

This statement is simply incorrect. The term “margin revenues” refers to the revenues collected from ratepayers rather than the costs incurred by the utility. If a utility is able to lower costs, then a decline in margin revenues does not necessarily mean the utility has failed to recover its cost of service as Mr. Feingold seeks to imply.

Furthermore, problems arise when Mr. Feingold seeks to give the concept credence by referring to the Companies’ “approved level of margin revenues.” He admits under cross-examination that the Commission has never used the term “margin revenues” in a previous rate order. (Tr. 1372, lines 17-22) Needless to say, up to this point, the Commission has never approved a specific level of margin revenues for Peoples Gas, North Shore or any other gas utility in Illinois for that matter. (ICC Staff Ex. 20.0, p. 2, lines 33-36)

The above discussion indicates that the proposed Rider VBA suffers from numerous deficiencies. For the reasons stated above it should be rejected by the Commission in this proceeding.

2. Staff Alternative Language Changes To Rider VBA

If the Commission determines it is appropriate for the Companies to adjust base rates on a monthly basis for fluctuations in actual revenues, Staff recommends the Commission adopt the language changes which are reflected in legislative style in Attachment C, Staff Revised VBA, to ICC Staff Exhibit 1.0. The changes are: 1) to reflect an annual reconciliation with possible adjustments to ensure the VBA is in compliance with the tariff; 2) to change the monthly filing date to allow for Staff review prior to the effective date; and 3) to require the Companies perform annual internal audits on compliance of the UBA. The Companies stated no opposition to these proposals, other than one change in the definition of RA. (North Shore/Peoples Gas Ex. VG-2.0, p. 50) In Staff's rebuttal testimony, Staff stated no opposition to the Companies rebuttal changes. (ICC Staff Exhibit 13.0, p. 15)

3. Alternative Proposal for Weather Normalization Adjustment – Rider WNA

The retroactive ratemaking and single-issue ratemaking violations discussed above for Rider VBA also apply to Rider WNA, and will not be repeated here. Like Rider VBA, Rider WNA attempts to ensure the recovery of revenues – only the adjustment mechanism is limited to revenue impacts caused by variations in weather. Moreover, as explained below, the Companies' justification for Rider WNA is flawed and inadequate.

The proposed Rider WNA, which was developed as an alternative to Rider VBA, presents its own set of problems and should be rejected by the Commission as well. The rider would adjust usage charges for SC 1N (Small Residential Non-Heating), 1H (Small Residential Heating) and 2 (General Service) during the winter heating season according to the temperature. If temperatures are below normal, the charges would be adjusted upwards and if temperatures exceed normal, a downward adjustment would be made. The key difference between the two riders is that Rider WNA adjusts revenues solely to address changes in the weather during the winter heating season while Rider VBA's adjustments were designed to preserve a fixed level of margin revenues throughout the year.

Because Rider WNA is based on weather only, it undermines the Companies' incentive to encourage ratepayers to conserve. If ratepayers do conserve and consumption declines, there would be no consequent adjustment in the Companies' revenues under the proposed Rider WNA. Therefore, to the extent that ratepayers conserve, Peoples Gas and North Shore will suffer revenue erosion under the proposed rider. Thus, one of the key selling points for Rider VBA disappears under the proposed Rider WNA. (ICC Staff Ex.20.0, p. 31, lines 699-706)

The proposed rider presents other problems as well. According to the Companies' own testimony, Rider WNA will serve as a revenue-enhancing tool. The proposed rider will adjust revenues according to the relationship of temperatures in future years to temperatures for the months of October 2005 through May 2006. Companies witness Tackle testifies that the number of Heating Degree Days (HDD) should rise on an overall basis over the next six to ten years. (Peoples Gas Ex. EST-1.0, p. 2, lines 25-28) If that were to happen, then the Companies would enjoy an upward adjustment in revenues overall due to Rider WNA over this time period. Thus, based on the forecast of Companies' witness Tackle, Peoples Gas and North Shore will receive greater revenues and ratepayers will pay higher gas bills as a result of Rider WNA. (ICC Staff Ex.20.0, pp. 31-32, lines 713-722)

In addition, it is not clear why Peoples Gas and North Shore need this additional revenue rider. As previously noted, the Companies have demonstrated an ability to operate successfully within the confines of the traditional regulatory paradigm. They have been able to avoid filing a new rate case for a full 12 years and have earned rates of return at or above their authorized levels for a number of years within this period. In addition, they are requesting a ten-year weather normalization period, which Staff does not oppose. (ICC Staff Ex.20.0, p. 32, lines 725-731)

Furthermore, Peoples Gas and North Shore have not satisfactorily demonstrated why they alone among Illinois gas utilities require this kind of rider. For example, Northern Illinois Gas ((NICOR), Illinois' largest gas utility requested only a reduction in the weather-normalization period from 30 to 10 years in its recent rate case. It did not seek any additional riders to address temperature changes beyond the test year. If NICOR found this proposal sufficient for its operating needs, it is not clear why Peoples Gas and North Shore should have the further need of a rider to address future weather changes. (ICC Staff Ex.20.0, p. 32, lines 733-741)

In addition, the concerns about the regulatory burden for Rider VBA also extend to Rider WNA. The proposed rider will also require significant regulatory resources to oversee without providing meaningful ratepayer benefits. Furthermore, if Rider WNA is approved for Peoples Gas and North Shore, that will set a precedent for other gas utilities in Illinois to seek similar ratemaking treatment and thereby place an even greater burden on the regulatory process. (ICC Staff Ex.20.0, p. 33, lines 745-750)

4. Staff Alternative Language Changes To Rider WNA

If the Commission determines it is appropriate for the Companies to adjust base rates on a monthly basis for weather variations, Staff recommends two changes to Rider WNA. First, in Section D of Rider WNA, Staff recommends that the annual report be filed with the Chief Clerk. Further, Staff recommends that the filing of the annual report initiate an annual ICC review of compliance of WNA for the preceding year. (ICC Staff Exhibit 13.0, p. 21) The Companies stated no objections to Staff's recommendations. (North Shore/Peoples Gas Ex. VG-3.0, p. 27, lines 583-586)

C. Rider ICR

1. Overview of Rider ICR

Rider ICR would apply only to Peoples Gas. Rider ICR is designed to recover costs associated with Peoples Gas' proposed accelerated cast iron and ductile iron (CI/DI) main replacement program and other investments associated with Accounts 376 (Mains), 380 (Services), 381 (Meters), 382 (Meter Installations) and 383 (House Regulators) (collectively "ancillary infrastructure"). (Peoples Gas Ex. VG-1.0, p. 49, lines 1088-1091) The Company is currently replacing CI/DI, but would like to increase the rate at which it is replaced without having to file another rate case to collect the monetary amount required to accelerate the program. (Peoples Gas Ex. JSF-1.0, p. 4, lines 80-83) The proposed rider would feature an annual charge billed to ratepayers on a monthly basis. The annual charge would be the difference between a "baseline" level of capital expenditures, the average of capital expenditures from fiscal years 2004, 2005, and 2006, and corresponding expenditures in the year prior to billing. (Peoples Gas Ex. RAF-1.0, pp. 45-46, lines 902-907; Peoples Gas Ex. JFS-1.0, pp 3-4, lines 65-72) For example, the amount that Peoples Gas spends in 2007 over the average amount spent in fiscal years 2004, 2005, and 2006 would be billed to the customer, on a per customer, per month charge, starting in April of 2008.

2. Company's Support of Rider ICR

Peoples Gas' witness Feingold presents three main arguments to justify the proposed rider. In addressing the first of his arguments, Mr. Feingold states that conducting an accelerated replacement program would be difficult under traditional regulation because the additional costs of replacement would not be recoverable until after Peoples Gas' next rate case. Furthermore, if that prevented the Company from pursuing an accelerated program, he argues that opportunities for "longer-term cost savings" would be foregone. (Peoples Gas Ex. RAF-1.0, p. 45, lines 885-892)

Company witness Schott also discusses the accelerated main replacement program that would be conducted under Rider ICR. He identifies the benefits of the accelerated program to be, incurring costs now rather than later; reducing maintenance costs associated with leaks that arise under the current low-pressure system; and lower street repair costs resulting from main replacement activities. (Peoples Gas Ex. JFS-1.0 at 7, lines 139-150)

Mr. Schott's third perceived benefit assumes that the Company would take advantage of unexpected opportunities for main replacement arising from special projects and events (e.g., Chicago's bid to host the Olympics in 2012). He claims these opportunities could provide significant cost savings and expedite CI/DI replacement. (Id. At 11, lines 227-231) To take advantage of these opportunities, Mr. Schott believes that Rider ICR is essential, because the opportunities cannot be known in advance and, therefore, cannot be budgeted. (Id. At 12, lines 254-260)

Mr. Schott further contends that the proposed Rider ICR is necessary to address financial risk. He argues that the magnitude of the costs under the accelerated replacement program would be too great to recover through the traditional rate case process. Thus, he contends, the proposed Rider ICR is needed to avoid the potential risk. (Id. At 13, lines 278-287)

3. Staff's Arguments Against Rider ICR

a. Peoples Gas has not justified Rider ICR

The Company has not justified rider recovery treatment of its Accelerated Replacement Program ("ARP"); therefore, the Commission cannot approve Rider ICR. While the Commission has statutory authority to approve rider recovery, when warranted (*City of Chicago v. Illinois Commerce Comm'n*, 13 Ill.2d at 611), the Commission cannot approve a rider that singles out an expense or cost that cannot be distinguished from other expenses typically recovered in a rate proceeding under rate base. (*A. Finkl & Sons Co. v. Illinois Commerce Comm'n,* 250 Ill. App.3d at 325-326 citing *BPI II* at 244-245) The Commission is also prohibited in enacting incentive based riders. (*Id.* at 327) The Commission can, however, approve a rider that recovers costs that are volatile, fluctuating, and unpredictable. (CILCO v. ICC, 255 Ill.App.3d at 885)

As discussed above, the First District court in *A.Finkl v. ICC* found that Commission approval of a demand side management rider violated the prohibition of single-issue ratemaking by considering "changes to components of the revenue requirement in isolation." (250 Ill. App.3d at 325) Rider ICR isolates the incremental cost of accelerating the Company's main replacement program, and adds the cost to ratepayers' monthly bills. (Peoples Gas Ex. VG-1.1, pp. 142-144) During traditional rate making, utilities submit for consideration by the Commission, for inclusion in its rate base, all infrastructure expenditure costs. The Commission can then consider those costs in conjunction with revenues and rate of return, all part of the revenue requirement formula that determines rates. Rider ICR, however, isolates one component of the revenue requirement, and increases customer monthly rates, all without the Commission's review or approval.

Company witness Schott testified, during cross examination, that the only completely accurate way to account for all variables impacted by the installation of CI/DI replacement facilities is in a rate case. (Tr., p. 1576) Mr. Schott also testified that all costs associated with the Company's main replacement program are eligible to be included in rate base. (Tr. P. 1620) Thus, the CI/DI costs are the type of costs typically recovered through base rates.

Also in *Finkl,* the court held that it is improper for a rider to place an incentive on "a legally required act." (*Id.* at 327) As will be discussed below, the Company's motivation for accelerating CI/DI replacement is first, to increase "safety and reliability," (Peoples Gas Ex. ED-1.0, p.18, lines 370-371), and second to "shorten[] the projected replacement time and reduc[e the] overall cost." (Peoples Gas Ex. JFS-1.0, p. 1, line 13) Nevertheless, the Company admits that Rider ICR creates a financial incentive to accelerate main replacement. Witness Schott testifies that "Rider ICR will enable Peoples Gas to take advantage of more opportunities to replace portions of its gas system **without the negative financial consequences** such business actions would create under traditional ratemaking methods." (Id. at p4, lines 77-80) (emphasis added) Thus, the Company is motivated to accelerate the current program because it will be able to earn a rate of return on investments not considered in rate base of its most recent rate proceeding. Rider ICR, therefore, creates an incentive to accelerate the current program and incur costs that would otherwise not be incurred. In *Finkl*, the court found removing barriers least cost planning as justification for the rider created an illegal incentive. Similarly, in the instant proceeding, Rider ICR, removes barriers to increasing investment in plant infrastructure.

Lastly, the courts have long held that riders may be warranted when costs are volatile, fluctuating, or unpredictable. The Company, however, has not been able to justify the need for a rider based on that criteria. In fact, the Company has testified that acceleration is and will continue to be at the discretion of the Company. (Tr. P. 1617) Moreover, there is no urgent need to accelerate the main replacement program. The Company claims benefits to the Rider, but cannot quantify any detriment if the Rider is not approved. (Tr., p. 1621) Also, as far as benefits are concerned, they do not appear to be enough for the Company to commitment to less frequent rate cases if its proposal is adopted. (Tr., p. 1540)

b. The Company's Arguments in Support of Rider ICR are Flawed

Peoples Gas does not justify why ratepayers should be asked to pay an extraordinary price for ordinary gas utility service. The purpose of the accelerated main replacement program is not to provide any new or enhanced service to ratepayers. Rather, the expenditures for this program are incurred so that Peoples Gas can continue to furnish basic gas service to its customers. According to Peoples Gas witness Doerk, "[t]he overarching motivation for replacing cast iron main is the safety and reliability of service for customers. (Peoples Gas Ex. ED-1.0, p.18, lines 370-371) As with any other public utility, Peoples Gas has a statutory obligation to provide safe and reliable service at minimum cost. If minimum cost requires an accelerated main-replacement program then that should be Peoples Gas' objective. Peoples Gas should not receive an additional financial reward,[30] as would be provided by Rider ICR, to fulfill its obligation to maintain a safe and reliable system when every other gas utility in Illinois is obligated to do the same without the benefit of this reward. (ICC Staff Exhibit 8.0, p. 37, lines 760-773)

The argument that the rider would enable the Company to take advantage of opportunities that produce long-term savings is problematic. Peoples Gas is asking ratepayers to pay additional costs for possible future savings under the main replacement program. However, the Company does not explain what these future savings are or whether they will outweigh the additional costs paid by ratepayers under the proposed rider. (ICC Staff Exhibit 8.0, pp. 36-37, lines 754-758)

Company witness Schott responds to this argument by claiming that the Company only seeks to accelerate costs but not to have ratepayers pay additional costs. (North Shore/Peoples Gas Ex. JFS-2.0, pp. 18-19, lines 368-376) However, his statement is inaccurate. Under traditional regulation, the costs associated with infrastructure investment that ratepayers pay for do not change between rate cases. That could change if Rider ICR is approved. The costs passed through between rate cases under Rider ICR will be additional costs that ratepayers would not pay otherwise. (ICC Staff Exhibit 20.0, p. 28, lines 619-631)

It is difficult to understand the argument by Peoples Gas that the rider is needed for opportunities that cannot be known in advance and, thus, cannot be budgeted. Peoples Gas has been providing service to customers in Chicago since the 1850s.

[30] Peoples Gas, and any other Illinois Utility, under traditional ratemaking earns a rate of return on its rate base. If the rate base is $10M and the rate of return is 10%, Peoples Gas earns $1M. Rate base is set for the test year, but it fluctuates on any given year, based on the actual plant in service.

(http://www.answers.com/topic/peoples-energy-corp, Viewed June 15, 2007) After 150 years, it should be accustomed to dealing with special projects and events sponsored by the City and other parties. Furthermore, since 1981 Peoples Gas has been able to conduct a main replacement program without the need of a rider, demonstrating that it is possible to plan and budget for a main replacement program despite the existence of special projects and events. (ICC Staff Exhibit 8.0, pp. 37-38, lines 775-785)

It would seem that any main-replacement program, accelerated or not, must coordinate with the City or a pertinent third party for construction efforts to be cost effective. If coordination can lower costs, it should be pursued whether the replacement program proceeds at a normal or accelerated pace. Company witness Schott testifies, "Peoples Gas has historically coordinated main replacement with the City of Chicago during its normal rebuilding or replacement of roads in Chicago." (Peoples Gas Ex. JFS-1.0, p. 10, lines 224-225) If Peoples Gas could coordinate in the past without the benefit of a rider, then it is not clear why a rider is needed for future coordination. If anything, Peoples Gas should be expected to have learned from experience and coordinate with the City more efficiently on a going-forward basis. (ICC Staff Exhibit 8.0, p. 38, lines 787-798)

The Company's concern about the financial risk of a costly accelerated replacement program under traditional regulation should be dismissed. This argument reveals the extent to which the Company is seeking a blank check from ratepayers for a large project of unknown cost. Mr. Schott considers it difficult to predict, "when and how much money will be spent" under the proposed program. Nevertheless, he considers the costs "too great" to expose Peoples Gas to the financial risk. However, he is willing to expose ratepayers to that risk through the introduction of Rider ICR. (ICC Staff Exhibit 8.0, p. 39, lines 804-816)

Adoption of the proposed rider would relegate ratepayers to paying incremental costs associated with this program until Peoples Gas files its next rate case. Considering that Peoples Gas has stayed away for twelve years since its last case, ratepayers could end up paying these unknown incremental costs for a long time under the proposed rider.

The proposed rider also undermines Peoples Gas' incentive to control costs. Peoples Gas will be permitted under the rider to recover incremental investments in ancillary infrastructure associated with mains, services, and meters from ratepayers. Because it will not have to wait until the next rate case to recover incremental investments, Peoples Gas will have the incentive to spend additional amounts more quickly. This could undermine the objective of controlling costs. (ICC Staff Exhibit 8.0, pp. 39-40, lines 818-829)

Mr. Schott takes issue with this contention. He claims that the Company must continue to be efficient and control costs with Rider ICR under the accelerated replacement program based on the guidance provided by the Kiefner report. Mr. Schott also argues that the Company needs to be competitive to attract new customers, retain existing customers, and compete with alternative suppliers. (North Shore/Peoples Gas Ex. JFS-2.0, pp. 19-20, lines 388-402) However, the fact remains that even with a cap in place, the opportunity to recover incremental investments between rate cases gives the Company an incentive to spend more.

The rider could also undermine efficiency by allowing the Company to substitute short-term spending decisions for longer-term plans. These incentives could undermine the kind of careful decision-making necessary to keep utility costs at a minimum. (ICC Staff. Ex. 20.0, p. 29, lines 663-665)

Mr. Schott's statement that Peoples needs to be efficient to attract new customers, retain existing customers, and compete with alternative suppliers is irrelevant. Peoples Gas is a regulated monopoly with no competition in the city of Chicago for the delivery of natural gas. Under these circumstances, it is not clear how an increase in delivery costs would affect either the number of gas customers or the ability of Peoples Gas to compete with alternative energy suppliers. (ICC Staff Exhibit 20.0, pp.29-30, lines 643-666)

The proposed Rider ICR is clearly misguided. It should be rejected by the Commission along with the other riders being proposed.

4. Staff Alternative to Rider ICR

If the Commission determines it is appropriate for Peoples Gas to recover the cost of its Accelerated Replacement Program through a rider, Staff recommends the Commission adopt certain revisions to Rider ICR originally reflected in Attachment A to ICC Staff Exhibit 1.0 -- including renaming the rider as Rider QIP, an acronym for Qualifying Infrastructure Plant . These proposed revisions are based on language and provisions contained in 83 Ill. Adm. Code 656 ("Part 656"), the Commission's rule for the qualifying infrastructure plant surcharge for water and sewer utilities. Rider recovery of a qualifying infrastructure plant surcharge for water and sewer utilities is statutorily authorized by Section 9-220.2 of the PUA. (220 ILCS 5/9-220.2) While neither the statutory authorization for rider recovery of qualifying infrastructure plant nor the Commission's rule adopted pursuant to Section 9-220.2 apply to gas utilities, and Staff's position is that Peoples Gas' proposal for rider recovery of plant costs should not be approved, Part 656 provides a reasonable starting point, should the Commission decide that rider recovery of plant costs is appropriate, for analysis and consideration of the specific terms and conditions of any rider allowing recovery of plant costs. (ICC Staff Exhibit 1.0, pp. 21-22)

In rebuttal testimony, Peoples Gas did not object to four key components of Staff's alternative proposal, those being: (1) a criterion that only the costs of an accelerated cast iron/ ductile iron ("CI/DI") main replacement program are recovered in the Rider mechanism through the provision of specific eligibility criteria; (2) creation of a separate revenue sub-account; (3) a cap of 5% of base rate revenues; and (4) an annual reconciliation including a review of prudently-incurred costs. (North Shore/Peoples Gas Ex. JFS-2.0, pp. 4-5, lines 64-81) In surrebuttal testimony, however, Peoples Gas objected to Staff's proposal (contained in direct testimony) for a return credit in Rider QIP should the Company's actual earnings during operation of the rider exceed its authorized rate of return. (North Shore/Peoples Gas Ex. JFS--3.0 2-REV, pp. 1-6). The Company's final version of changes to Staff's Rider QIP that it accepts was provided in the Company's response to Administrative Law Judge Data Request ALJ 3.01, subsequently admitted as ALJ Exhibit 1. ALJ Exhibit 1 indicates that the Company does not accept the return credit provision contained in paragraph (c) of

Section H of Appendix A to ICC Staff Exhibit 1.0, as that section is struck in its entirety in ALJ Exhibit 1.

The language at issue regarding a return credit reads as follows:

> c) In the annual reconciliation, the utility shall include data showing operating income and rate base for the reconciliation year, such data being developed in accordance with subsection (f)(4). If, for any such rate zone, the actual rate of return on rate base for the reconciliation year exceeds the overall rate of return allowed in the utility's last rate proceeding, revenues collected under the QIP surcharge rider shall be reflected as a credit through the R component of the QIP surcharge to the extent that such revenues contributed to the realization of a rate of return above the last approved level. A credit value for the R component will result in a reduction of the QIP surcharge percentage. To the extent, if any, that a required adjustment for a reconciliation year has not been already made by the utility (through the R component), the Commission shall require (through the O component) that such an adjustment be made after the annual reconciliation hearing.

This provision ensures that ratepayers will not make additional payments to the Company between rate cases under Rider QIP to the extent that the Company's actual earnings exceed its most recently authorized rate of return – a situation that the Company acknowledges could occur. (Tr., p. 1614) This provision is fair, reasonable and necessary. Even if the Commission determines that it is otherwise appropriate for rider recovery of CI/DI main replacement costs, the Company's proposal to disregard the significant single-issue ratemaking concerns raised by Staff and others by excluding a provision that would otherwise moderate those concerns -- by limiting the potential for payments under Rider ICR at the same time the Company is earning in excess of its authorized rate of return -- simply invites the Commission to partake in an abuse of discretion.

The Company argues that the return credit provision complicates the rider, which it intended to be an uncomplicated mechanism to recover only return and depreciation of the Accelerated Program. The Company contends that the effort required to determine the credit and then audit the credit will approach the amount of effort required for a full blown rate case. (North Shore/Peoples Gas Ex. JFS--3.0 2-REV, pp. 1-2, lines 52-82 and pp. 2-3, lines 86-90). The Company's argument that this provision is somehow too burdensome lacks merit and is simply a red herring. This same provision applies to water utilities under Part 656, and the Company provided no evidence that it has resulted in the dour consequences asserted by the Company here. (Tr., pp. 1646-1647)

The Company admits it did not study the refund provision until responding to Staff's rebuttal testimony (Tr. P. 1646) although the proposal was formally made by Staff in direct and made known to the Company early in the proceeding through discovery. The Company further admits that while it does not understand why a water company would agree to the provisions of Part 656, it did no study of the issue to possibly address its concerns. (Tr. pp. 1646-1647) Finally, while admitting no research of the issue, the Company states that the refund provision would be more material to Peoples Gas since it is a larger company than the water companies. (Tr. pp. 1648-1649) The Company's objections to the refund provision are without merit. The Company obviously did not seriously consider the issue until late in the proceeding, despite Staff's open presentation of the issue. The Company presents only its opinion of what it thinks might happen if the refund provision is enacted. It presented no valid evidence or facts why a reasonable protection against over earnings, used to protect water rate payers, is somehow invalid for this Company.

The Company admits that without the credit provision, it could recover additional costs under the rider at the same time it is earning in excess of its authorized rate of return. (Tr., pp. 1613-1614) It further opines that excess earnings have no bearing on whether or not the rider is fair and equitable. (Tr., p. 1622) For example, the Company states that Rider ICR should be allowed to increase rates and revenues with no penalty, i.e. credit or refund, to the Company for earnings growth caused by weather. (Tr., p. 1590) The Company incorrectly believes that the revenues collected from Rider ICR cannot contribute to over-earning since those revenues are to recover costs. (Tr., p. 1587)

The Company contends that the credit provision could eliminate recovery of the very costs the rider is designed to recover and be a disincentive to conduct infrastructure replacement. (North Shore/Peoples Gas Ex. JFS--3.0 2-REV, pp. 3-4, lines 92-116). The return credit provision reduces recoveries under Rider ICR to the extent that the Company is actually earning in excess of its authorized rate of return. This feature of Staff's alternative proposal does not deny the Company recovery of any costs; rather, it has the effect of requiring or permitting the Company to recover such cost through its actual excess earnings. This feature is fair to both ratepayers and the Company, as the Company is put in no worse a position than it would be if it had been able to capture those costs in a base rate proceeding where costs and earnings would be considered in the aggregate.

According to the Company, whether or not its actual earnings turn out to be in excess of its authorized rate of return should have no bearing whatsoever on its ability to obtain single-issue treatment and recovery of the costs subject to Rider ICR. (Tr., pp.

1621-1622) The Company's position evinces an inappropriate insensitivity to the interests of ratepayers, and is directly at odds with the prohibition against single-issue ratemaking. As explained by our supreme court in *Business & Professional People for the Public Interest v. Illinois Commerce Comm'n*, 146 Ill. 2d 175, 244-45 (1991):

> The rule against single-issue ratemaking recognizes that the revenue formula is designed to determine the revenue requirement based on the *aggregate* costs and demand of the utility. Therefore, it would be improper to consider changes to components of the revenue requirement in isolation. Often times a change in one item of the revenue formula is offset by a corresponding change in another component of the formula. For example, an increase in depreciation expense attributable to a new plant *may* be offset by a decrease in the cost of labor due to increased productivity, or by increased demand for electricity.

Riders are closely scrutinized to guard against the danger of ignoring some items that impact the overall revenue requirement. *City of Chicago v. Illinois Commerce Comm'n*, 281 Ill. App. 3d 617, 628-629 (1st Dist. 1996) The inherent danger is that while "potential changes in one or more items of expense or revenue may be offset by increases or decreases in other such items, single-issue ratemaking considers those changes in isolation, ignoring the totality of circumstances." *A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317, 325 (1st Dist. 1993) The return credit proposed by Staff seeks to reduce the danger inherent in permitting single-issue treatment of the costs subject to Rider ICR by putting some check on the ability to receive such treatment. The Company, on the other hand, seeks to ensure its ability to obtain single-issue treatment of Rider ICR cost notwithstanding the existence of offsetting factors.

As discussed earlier, Staff believes the Company has failed to identify any circumstances justifying rider treatment of ICR costs. In the event the Commission disagrees, including the return credit provision would be essential to a sustainable

Commission finding that rider recovery is warranted. Moreover, given that the Commission exercises a discretionary authority to permit rider recovery in an appropriate case, it would be completely within the Commission's power to condition the exercise of its discretionary authority on inclusion of the return credit provision.

The Company also asserted that no other Company riders are subject to a credit provision based upon earnings. (Id, p. 6, lines 127-128) This point rings hollow. The Company admits that it has no other riders that provide recovery of a return on capital expenditures. (Tr., p. 1615) Rider ICR allows the Company to earn a return on infrastructure investments that occur between rate cases. It is both reasonable and logical for a rider permitting a return on additional investments be subject to a credit provision based upon earnings.

D. Rider EEP (Merits of Energy Efficiency Program and Rate Treatment)

1. Merits of Proposed Energy Efficiency Program

The Companies initial filing includes a proposal to implement an Enhanced Efficiency Program ("EEP") to promote its customers' energy efficiency (North Shore Ex. IR-1.0, pp. 1-18; Peoples Gas Ex. IR-1.0, pp. 1-18) The EEP will consist of a Governance Board, which chooses the EEP's employees, provides direction to the employees about which energy efficiency programs to fund and the amount of the program's funding. The employees are split into categories that specialize in administration (Contract Administrator), implementation (Program Administrator) and evaluation (Program Evaluator). The Companies also recommend that the program undergo a periodic review by a third party. (ICC Staff Exhibit 12.0 Revised, p. 31) The

EEP does not propose any specific initiatives, although Companies' witness Rukis discusses several types of programs and technologies that could be implemented. But specific initiatives are left to the EEP after it has been constituted. (Id., p. 32) The Companies are asking ratepayers to fund programs that are not specified. As Staff witness Rearden testified, the Companies cannot guarantee to the Commission that these pledges will necessarily translate into prudent expenditures. (Id., p. 37-38)

Given these concerns, Staff recommends that the Commission reject the EEP. Staff has two other concerns with the Companies' proposed EEP. First, the program is not equitable. It is funded by all ratepayers, but not all ratepayers benefit. While the program may benefit ratepayers as a group, some ratepayers will not. This is arguably inequitable. Second, it's inefficient because it taxes customers to fund the program, and it may fund uneconomic programs. Third, Staff believes that the program design is flawed. In particular, Staff has reservations about the program's governance. (Id., p. 32)

The EEP is inequitable because the expenditures are recovered from all ratepayers, but the direct benefits only accrue to a limited subset of ratepayers. Some ratepayers will see few or no benefits from the program. Some examples are homeowners that have just upgraded their houses or bought new ones. Others are renters whose apartment manager doesn't take advantage of the program. And still others that view the return on their conservation investment as too low even with the benefits provided by an EEP. It is impossible to compare the cost that one individual has to pay with the benefits that others receive. There is no way to objectively determine that one individual's gain is worth more than another individual's loss. Social welfare can only be improved when the winners' gains do not come at the expense of the losers. (Id., pp. 32-36)

The EEP is inefficient, because the conditions that are most likely to lead to demand for EEP services are those that provide the best incentive to invest in conservation without an EEP. As gas prices rise, the return to saving gas usage increases, and there are more incentives for individual businesses and consumers to invest in conservation technology without any utility program. No base case for conservation spending absent the EEP has been established. Therefore there is no way to measure the incremental effect of the EEP. While the benefits are likely to outweigh the cost for ratepayers receiving program benefits, it is less clear that this is true for ratepayers as a whole. For the entire program to have net benefits, the value of the gain in technical efficiency from the program must be higher than the cost. (Id., pp. 33-36)

Even if the EEP has net benefits as a whole, an efficient outcome is not guaranteed. Some customers may be induced to invest in projects that are not cost effective by themselves, but the whole program may still have net benefits on average. Efficiency requires that the last individual project undertaken have net benefits. As shown in Dr. Rearden's net benefits chart on page 35 of his revised direct testimony, the efficient number of projects are all those with individual positive net benefits (those projects encompassed in the box to the left). The larger box illustrates a set of projects that have positive net benefits as a group, but it includes individual projects that have net negative returns and so should not be undertaken. (Id., p. 34); See also, September 11, 2007 Tr., pp. 710-716)

Staff does not support using utility rates to fund conservation programs. It is concerned that such programs may reduce economic efficiency. If utility rates are increased to pay for such programs, then all customers pay for programs that benefit only some of the customers. In addition, ratepayers who may be investing at efficient levels absent the program might be induced to start investing in too much conservation by investing in projects that have negative net returns. This reduces economic efficiency. In contrast, a program financed through an income or property tax would have a smaller decrease in efficiency. As Dr. Rearden testified, one principle of public finance is that a tax has a smaller reduction of efficiency when the base on which the tax is levied is larger. An income or property tax is broadly based, so that for a given program size, the taxes collected are less than a surcharge (effectively a tax) on gas volumes. (ICC Staff Exhibit 12.0 Revised, pp. 35-36)

Staff acknowledges that state-wide or national programs might suffer from these same core problems, but Staff believes that these problems are smaller and simpler in more broadly based programs. For a given program size, the larger the funding base, the less the efficiency cost. However, the Commission's task is to establish utility rates that provide a reasonable return to utility shareholders while allowing cost recovery of prudent expenditures only. This means that the EEP should not only have net benefits over all ratepayers including any efficiency cost to ratepayers, but the EEP must also be efficiently administered. The Commission has to find that the public interest is served by making some ratepayers better off at the expense of another group of ratepayers. (Id., p. 36)

Staff finds the EEP design to be flawed. Staff has several concerns with how the EEP is administered. Foremost is that the lines of command are not clear. That is, it is not clear who controls which functions and who makes what decisions. This is important since it does not appear that the Administrators are accountable to anyone. The organizational chart for the program (North Shore Ex. IR-1.1 and Peoples Gas Ex. IR-1.1) demonstrates this concern. There is an arrow from the Control Administrator to the Board and an arrow from the Board to the Program Administrator, but the chart does not indicate to whom the Administrators report. There does not appear to be any way for the Board to limit administrative costs. Administrative costs reduce the benefit of the EEP. If they are too high, the extra costs might seriously undercut the EEP's effectiveness. (ICC Staff Exhibit 12.0 Revised, pp. 36-37)

Staff recommends that the organization be one that is accountable and efficient. The Board should appoint a Director that has clear authority to act both with respect to employees and programs. Employees should be enabled to select and administer the programs under the authority of the Director. It is not clear that the Program Evaluators need to be a separate group of employees. The Director should use the inputs of the employees to select programs that the employees can evaluate. One way to help make the process effective is to conduct periodic management audits and use annual reports about the programs' effectiveness. These changes should be made no matter the method of rate recovery, i.e. rider or base rates. (Id., p. 37) An important control that the Commission should impose on the EEP is to have a binding constraint on the amount of administrative costs that are incurred. The Commission should impose such a constraint and enforce it by requiring the Companies to periodically report their EEP overheads. (Id.)

The Environmental Law and Policy Center ("ELPC") supports the EEP.[31] ELPC witness Kubert gives three reasons why the Commission should approve the program. First, he asserts that there is chronic underinvestment in energy efficiency, but at the same time, he admits that many customers have begun to increase their investments. (ELPC Ex. 2.0, p. 4; September 14, 2007 Transcript, Tr., p. 1426) And he asserts that the EEP can "...help to overcome many of these barriers by providing financial incentives, technical assistance and education to residential and commercial customers, retailers, distributors and contractors." (ELPC Ex. 1.0, p. 3) However, no empirical evidence was introduced to conclude that there is not enough investment in energy efficiency. (September 14, 2007 Transcript, Tr., p. 1423) ELPC does not provide testimony that defines the "right" investment level, and it does not state the current level of investment. Therefore, ELPC itself cannot logically conclude that there is underinvestment. Further, if there were underinvestment, ELPC does not consider other ways to correct market failure that may make ratepayers better off than the EEP. Finally, while ELPC witness Kubert refers to gas price increases as a reason for needing increased efficiency investment, he does not acknowledge the powerful incentive that higher prices themselves provide to induce more efficiency investment. (ICC Staff Exhibit 24.0 Corrected, pp. 35-36)

[31] However, ELPC supports the position that the EEP costs should be recovered in base rates not a rider as the Companies propose. (ELPC Ex. 1, pp. 6-7)

ELPC's second reason is that there is an economic development effect from reduced gas expenditures. ELPC witness Kubert asserts that spending dollars on energy efficiency that are funded by ratepayers, those dollars are diverted from paying for out of state gas to local vendors and workers providing energy efficiency services. And the customer savings that result from lower utility bills benefit state's economy as well. (ELPC Ex. 1.0, pp. 3-4) Staff concedes that there is an economic development effect from efficiency investment, but it is entirely unclear whether the development effect overcomes the lower utility bills when the EEP is not funded. Certainly, households may use the lower utility bills from not funding the EEP to finance efficiency investment, or they could allocate it in other ways in their budget. Economic theory generally holds that households are better off when they decide for themselves how to spend their money. ELPC proposes that the utility and the Commission decide for households how they should spend their money. (ICC Staff Exhibit 24.0 Corrected, pp. 36-37)

Finally, ELPC's third reason is that lower energy consumption lowers gas prices by reducing total demand for natural gas. (ELPS Ex. 1.0, p. 5) Staff does not agree that a conservation program in Chicago can lower gas prices in Chicago. The effect that the EEP can have on the Chicago citygate price is nil, since gas is priced in a national market. The size of the program relative to the national gas market is an infinitesimally percentage of total market demand in the United States and the effect that even a highly successful EEP could have on that market demand would be even smaller. (ICC Staff Exhibit 24.0 Corrected, pp. 37-38)

Finally, in the event that the Commission approves EEP, Staff agrees with the Companies' witness Rukis that EEP not be funded above $7.5 million per year. In addition Staff recommends that the Commission order the Companies to be responsible for the prudent choice of programs and efficient implementation of those programs. The Companies must be ultimately responsible for any EEP expenditures authorized. (Id., p. 38)

2. Proposal for Rider Recovery of EEP Costs

a. Overview of Rider EEP

The Companies' proposed Rider EEP (Enhanced Efficiency Program) is designed to charge, recover, and reconcile the budgeted and actual costs of an energy efficiency program for the eligible rate classes S.C. 1H and S.C. 2. (North Shore Ex. VG-1.0 2REV, pp. 35-36) The Companies propose a constant annual budget of $7.5 Million, proportionally divided between the two Companies, based on their share of the rate base. (Id. at 38) The Companies proposed that the rider work thusly: in December of 2007, the Companies would calculate the "Effective Component" by dividing the 2008 budget ($7.5M) by the forecasted number of customers (861,134[32]) and dividing it by 12 months to determine the per customer monthly increase for 2008. (Id. at 35-36) Under or over estimating the budget will then be reconciled in March of 2009, where the

[32] Peoples Gas S.C. 1H Sales and Transportation Customers Total: 621,352; S.C. 2 Sales and Transportation Customers Total: 84,139; North Shore Gas S.C. 1H Sales and Transportation Customers Total: 142,551; S.C. 2 Sales and Transportation Customers Total: 13,092. (Peoples Gas Schedule E-5, North Shore Gas Schedule E-5)

Companies will calculate how much customers over or under paid in 2008. That amount, with interest, will then be amortized over the next nine months. (Id. at 36)

The process then continues much the same way, except, the Companies, in accordance with their proposal, can carry-over up to 75% of the 2008 budget into 2009; subsequently they will carry 50%, 25%, and then 10% through the life of the program. (Id.) In December of 2008, the Companies will once again determine the "Effective Component" or customer charge for 2009 customers based on forecasted customer numbers. This charge will then be reconciled in March 2010, where the Companies will calculate if they should recover additional funds for program expenditures above the combined 2009 budget and the carry-over budget from 2008, or refund an over recovery of customer charges monies unspent under the carry-over limit. (Id.) This reconciliation will then be submitted to the Commission in a docketed reconciliation proceeding. (ICC Staff Ex. 1.0, Attachment D, p. 3) The Company will also file, with the Accounting Department of the ICC, and annual audit on July 1 of each year. (Id.)

b. Costs of Energy Efficiency Programs Should Not Be Recovered Through a Rider

As noted above, the Commission can approve "the direct recovery of unique costs through a rider when circumstances warrant such treatment." (*CUB v. ICC*, 166 Ill.2d at 136) One standard for recovery of expenses through a rider is that the expense to be recovered is volatile, unexpected, and likely to fluctuate. (CILCO v. ICC, 255 Ill.App.3d at 885) However, the Companies have not demonstrated that costs underlying the operating expenses associated with an energy efficiency program are or will be, volatile, fluctuating, or unpredictable. The Companies' witness, Ms. Grace, who introduced and sponsored the proposed rider, misguidedly lists two reasons why recovery of full and additional costs is appropriate under a rider. (North Shore Ex. VG-1.0 2REV, p. 37; Peoples Gas Ex. VG-1.0, pp. 41-42) First, Ms. Grace submits that the Companies previously collected conservation program costs through riders under a statewide least cost planning initiative. (Id.) Second and closely related, Ms. Grace notes that legislation had been offered at the time that she wrote her Direct Testimony "that may lead to a statewide energy efficiency initiative." (Id.) Nevertheless, the past initiative is no longer applicable, and the potential future initiative was not enacted into law. Thus, there is no legislative action to justify this rider, and no case law or Commission order that would then support such a rider.

The request for rider recovery of energy efficiency program costs is also similar to the proposal for recovery of a demand side management program costs held improper in *A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993). The instant proposal is improper under *Finkl*.

Moreover, Ms. Grace's testimony completely contradicts any argument that such costs are volatile, unpredictable, or fluctuating. The costs of the Companies' proposed energy efficiency program is budgeted at $7.5 million, but the Companies, with their experience in offering energy efficiency programs, know, and Ms. Grace testified, that it would take a few years to build up to the budgeted annual amount, thus when the Companies drafted Rider EEP, they predicted a slow start to the programs and embedded a mechanism that allowed for a carry over of 75% of the budget in the first year, 50% in the second, 25% in the third, and 10% every year there after. (North Shore Ex. VG-1.0 2REV at 36; Peoples Gas Ex. VG-1.0, p. 40)

c. The Companies Policy Arguments in Support of Rider EEP are Unsubstantiated

The Companies witness Feingold of Navigant Consulting discussed the policy aspects of implementing rider EEP. Mr. Feingold argued that the rider is necessary "because there are added uncertainties surrounding the precise timing of the rollout of its energy efficiency and conservation programs." He also considers it important to implement this rider so that "anticipated variations in budgeted versus actual costs from year to year" can be accommodated. (Peoples Gas Ex. RAF-1.0, p. 43, lines 848-855 and North Shore Ex. RAF-1.0, p. 40, lines 861-869)

Mr. Feingold's policy arguments are not compelling. He fails to substantiate his claim about the uncertainty of the proposed program and only serves to raise questions about the basis for the Companies' proposed energy efficiency and conservation programs. Staff disapproves of Rider EEP because approval of this rider will relegate ratepayers to paying in advance for an uncertain program that will be developed without the benefit of further regulatory review, thus exposing ratepayers to additional and unnecessary financial risk. (ICC Staff Exhibit 8.0, p. 33, lines 671-680)

Moreover, effective oversight of Rider EEP will require the devotion of significant regulatory resources. It would not make sense to establish this regulatory apparatus merely on the chance that future legislation may affect the Companies' expenditures in this area. (ICC Staff Exhibit 8.0, pp. 33-34, lines 682-691) Legislation that for the most recent session was not passed.

Furthermore, the discretion offered under the rider for the Companies to carry over amounts from one year to the next raises a concern. This significant funding flexibility could result in a significant gap between the budgeted expenditures and the amounts actually spent. This would create a gap between the policy objectives guiding the Commission's approval of the rider and the amount that is actually spent on the associated programs. (ICC Staff Exhibit 8.0, p.34, lines 696-701)

The magnitude of carry-over provision raises further questions about the program itself. The level of spending flexibility provided raises questions about the degree of progress in planning and developing the programs. Thus, it is not clear what kind of programs ratepayers will receive for their contributions to Rider EEP. (ICC Staff Exhibit 8.0, p. 34, lines 703-707) Staff therefore cannot recommend that the Commission blindly subject ratepayers to an out-of-rate-case rate increase.

3. Staff Alternative Language Changes To Rider EEP

If the Commission determines it is appropriate for the Companies to recover funds necessary to implement various energy conservation and efficiency programs through a rider mechanism, Staff recommends the Commission adopt the language changes which are reflected in legislative style in Attachment D, Staff Revised EEP, to ICC Staff Exhibit 1.0. The changes are: 1) to reflect an annual reconciliation with possible adjustments to ensure the EEP is in compliance with the tariff; 2) to change the monthly filing date to allow for Staff review prior to the effective date; and 3) to require the Companies perform annual internal audits on compliance of the EEP. The Companies stated no opposition to these proposals. (North Shore/Peoples Gas Ex. VG-2.0, p. 51)

E. Rider UBA

1. Proposal for Rider Recovery of Commodity Related Uncollectibles Expense

a. Overview

The Companies' proposed Rider UBA is designed to recover gas cost-related uncollectible expenses. (Peoples Gas Ex. VG-1.1, p. 54) Under the proposal, bad debt (i.e., uncollectible expenses) would be divided into two components: gas cost and non-gas cost. The non-gas cost component will continue to be recovered through base rates. However, uncollectible expenses associated with gas costs will be recovered separately through the proposed Rider UBA. The amount recovered through the rider will reflect the Companies' rate case allowed percentage of uncollectible expense as it is applied to forecasted gas costs, which is the estimated gas charge revenues. Any difference between billed revenues and actual expense will be reconciled by the Companies and filed with the Commission. (Peoples Gas Ex. VG-1.0, p. 44, lines 972-984 and North Shore Ex. VG-1.0, p. 39, lines 863-875)

b. Bad Debt Expenses are not Volatile, Unpredictable, or Fluctuating

The proposed Rider UBA is advocated by the Companies' witness Feingold who argues that the Companies' bad debt expenses are "volatile, unpredictable, and largely uncontrollable," particularly the portion of bad debt expense related to purchased gas costs. (Peoples Gas Ex. RAF-1.0, p. 41, lines 808-811 and North Shore Ex. RAF-1.0, pp. 38-39, lines 838-843) He contends that recent trends in natural gas prices have exacerbated the bad debt problems for gas utilities by raising customer bills, resulting "in more customers being slow or unable to pay, with resultant higher delinquent balances." (Id. Peoples Gas at 36-37, lines 723-728 and North Shore at 34, lines 732-

737) He seeks to buttress his argument by presenting Peoples Gas Exhibit LTB-1.5, which is designed to represent the volatility of bad debt expenses. (Id. Peoples Gas at 39, lines 769-774, and North Shore at 36, lines 780-785)

A recurring theme for the Companies is that 2001 through 2006 have been grave years for the Companies, while not grave enough to scare off a merger; they were grave enough to warrant the drastic departure from traditional ratemaking. Nevertheless, it must be noted and taken into account that the Companies where not precluded from apply for an increase in rates prior to 2007. In fact, it is very unlikely, and, Companies' witness Feingold acknowledged that other Illinois gas utilities do not abstain from Commission ratemaking proceedings for an unprecedented twelve years, like Peoples Gas and North Shore.

Mr. Feingold seeks to establish momentum for Rider UBA by arguing that bad debt riders have received significant support within the gas industry. (Id. Peoples Gas at 38-39, lines 755-768; North Shore at 35-36, lines 766-779) He references a 2005 Citigroup survey, which indicates 18 publicly traded gas utilities have a mechanism for addressing bad debt concerns. (Id.) Mr. Feingold also indicates that the Citigroup report goes on to note the high potential impact of bad debt to the earnings of Illinois utilities. (Id.) Later in his testimony, Mr. Feingold asserts that utility regulators in 10 states have approved a bad debt ratemaking mechanism for 17 gas utilities (Id. Peoples Gas at 41, lines 818-823; North Shore at 38, lines 830-835)

Mr. Feingold's argument for Rider UBA has no sound legal support. Mr. Feingold fails to establish the volatility of bad debt expenses in recent years. His supporting exhibit does demonstrate that Peoples Gas' total bad debt levels doubled from just under $20 million in 2000 to almost $40 million in 2001. However, what Mr. Feingold ignores, and what is more apparent in the exhibit is that total bad debt was relatively stable in all other years. From 1996 to 2000, it steadily declined from just over $25 million to just under $20 million. Between 2001 and 2003, the level was approximately $40 million each year. In 2004 and 2005, it dropped to $35 million each year. The relative stability for most of this decade suggests that uncollectible expenses are not quite as volatile and unpredictable as Mr. Feingold claims. (ICC Staff Ex.8.0, pp. 23-24, lines 522-535)

The corresponding exhibit for North Shore (North Shore Gas Ex. LTB-1.4) also demonstrates the unsupportable volatility theory Mr. Feingold sponsors. LTB 1.4 indicates that bad debt hovered between approximately $600,000 and $800,000 from 1996 to 2000 for North Shore Gas. (Id.) It then increased to almost $1.4 million in 2001 and ranged between approximately $1.2 million and $1.6 million between 2001 and 2005. (Id.) Thus, these figures also fail to indicate that North Shore's bad debt is volatile, as Mr. Feingold suggests. (ICC Staff Ex.8.0, p. 24, lines 537-542)

Moreover, Mr. Feingold is able to pinpoint the event that caused this so-called volatility—a sharp increase in gas prices in 2001. (Peoples Gas Ex. RAF-1.0 at 39, lines 774-775, and North Shore Ex. RAF-1.0 at 36, lines 785-786) Thus, the graph further demonstrates that the "volatile event" occurred once in ten years. Essentially, the question becomes, could gas prices spike in the future, as they did in 2001? This question further begs a new question: with the understanding that gas-price spikes may increase uncollectible expenses, should the Companies submit for a rate increase sooner than every twelve years?

Thus, the Companies' exhibit LTB 1.5 only demonstrates that price shock has caused an increase in uncollectibles, but it does not demonstrate that the Companies are now at the whim of a vastly fluctuating, unpredictable, and volatile expense. Nor is there anything unique about uncollectibles cost. As it happened once in twelve years, it stabilized the associated expense immediately after the shock, and it has not occurred in the last six years. Lastly, without rider UBA, the Commission will reset the Companies' rate case uncollectibles expense based on the test year, which is post 2001 that may take into account the higher overall uncollectibles expense that is seen on the graph. Thus, had the Companies submitted themselves for a rate case in 2001 or 2002, they would have easily avoided the costs they faced after the gas price spike in 2001 distorted their 1996 rate case uncollectible expense base rate settings.

Mr. Feingold cites a Citigroup Research report that supports Staff's position. Mr. Feingold cites the report to demonstrate that the financial community has recognized that bad debt is an issue that gas utilities are faced with. (Peoples Gas Ex. RAF-1.0, at 38-39, lines 753-768, North Shore Ex. RAF-1.0, at 35-36, lines 764-779) However, Mr. Feingold cannot demonstrate the same support from utility regulators. The report can only cite13 public utilities that have a bad debt tracker, suggesting limited support for this ratemaking approach. (Id. at Peoples at p. 38, line 761, North Shore at p. 35, line 772) Illinois alone has eight major gas and electric utilities, with four of them supplying both gas and electricity[33].

[33] 1) ComEd, 2) Nicor, 3) North Shore, 4) Peoples Gas, 5) MidAmerican (dual), 6) AmerenIP (dual), 7) AmerenCIPS(dual), and 8) AmerenCILCO(dual).

Furthermore, the statement by Citigroup Research that the lack of trackers across the country is “discouraging” which is contained in Mr. Feingold’s testimony further attests to the lack of regulatory support. (ICC Staff Ex.8.0, p. 30, lines 598-602) In his rebuttal testimony, Mr. Feingold contests the claim that regulatory support for bad debt trackers such as the proposed Rider UBA is limited. While only ten states have adopted such a tracker, Mr. Feingold argues that “industry-wide support for riders is growing rapidly” and cites “the large number of legislative, regulatory, and utility initiatives” recently undertaken for such ratemaking approaches. (North Shore/Peoples Gas Ex. RAF-2.0, p. 42, lines 855-859) Yet, Mr. Feingold only states his conclusion, and does not support them. His testimony does not indicate if there are more than the ten states the Citigroup report mentions that have implemented such rider mechanisms. Nor does he explain the large number of initiatives states have taken.

Moreover, Mr. Feingold’s words of optimism are belied by the Citigroup statement that he touts, when the report states that the lack of trackers is “discouraging,” and Mr. Feingold himself concedes that progress on these riders is “somewhat discouraging.” (Tr. p. 1370, line 14-1371, line 2) Thus, it is not clear why Mr. Feingold objects to the characterization of regulatory support for these trackers as limited, but it is telling that Mr. Feingold paraphrases one of the reports conclusion in the following way, “Citigroup estimated that the highest impact on earnings due to bad debt expense would be to those utilities that have a combination of high heating load, a high percentage of uncollectibles and a lack of regulatory relief.” (Peoples Gas Ex. RAF-1.0, at 38-39, lines 763-766, North Shore Ex. RAF-1.0, at 36, lines 775-776) While the record is bereft of facts depicting the Companies’ heating loads and collectibles expense percentage as “high,” the record is not devoid of the fact that the Companies have not subjected themselves to regulatory relief such as this for twelve years. Again, it must be asked: is this an issue for the Companies because costs are volatile, unpredictable, and fluctuating, or unique, or have the Companies allowed things to get out of their and the Commission’s hands because they have voluntarily removed themselves from “regulatory relief?”

Mr. Feingold’s claim that Peoples Gas’ bad debt expenses are volatile and unpredictable is further undermined by evidence presented in Staff Ex. 8.0. The exhibit compares uncollectible expenses with other operating expenses for Peoples Gas and North Shore. The comparison supports two conclusions. One is that the Companies’ uncollectible expenses are not significant relative to other operating expenses (less purchased gas costs); and, second, the Companies’ uncollectible expense fluctuates much less than those expenses. (ICC Staff Ex.8.0, pp.25-26, lines 556-565)

ICC Staff Ex. 8.0 demonstrates the contrary to be true. The Companies’ purchased gas costs are, in fact, volatile and do fluctuate compared with total operating expenses. Thus, unlike the Companies’ uncollectible expense, purchased gas costs fluctuate significantly and do warrant special rider treatment under the longstanding Purchased Gas Adjustment Rider. (ICC Staff Ex.8.0, pp. 28-29, lines 576-584)

In summary, the evidence undermines Mr. Feingold’s claim that uncollectible expenses are volatile and unpredictable. These uncollectible expenses do not meet that customary implementation standard and the proposed Rider UBA should be rejected.

Another factor to take into account is that even as uncollectibles expense climbed, Peoples Gas and North Shore were able to earn their Commission-authorized rates of return. In 2001 when bad debt costs increased significantly, Peoples Gas (North Shore) earned a return on common equity of 11.14% and 12.30%. When North Shore's uncollectibles expense rose by $660,000 in 2002, it still earned a return on equity of 12.72%. Thus, if Rider UBA had been in effect during this time, both utilities would have received additional revenue boosts despite earning at or above their authorized returns. This would amount to an unneeded benefit to the utilities at ratepayer expense. (ICC Staff Ex. 20.0, pp. 6-7, lines 131-140)

Thus, the Commission should not approve Rider UBA because it is not recovering a volatile, fluctuating, unpredictable, or unique cost, and it is against public policy.

2. Staff Alternative Language Changes To Rider UBA

If the Commission determines it is appropriate for the Companies to recover the cost of its commodity related uncollectibles expenses through a rider, Staff recommends the Commission adopt the language changes which are reflected in legislative style in Attachment B, Staff Revised UBA, to ICC Staff Exhibit 1.0. The changes are: 1) to reflect an annual reconciliation with possible adjustments to ensure the UBA is in compliance with the tariff; 2) to change the monthly filing date to allow for Staff review prior to the effective date; and 3) to require the Companies perform annual internal audits on compliance of the UBA. The Companies stated no opposition to these proposals, other than one change in the definition of RA. (North Shore/Peoples Gas Ex. VG-2.0, p. 50) In Staff's rebuttal testimony, Staff stated no opposition to the Companies rebuttal changes. (ICC Staff Exhibit 13.0, p. 15)

F. Deferred Accounting Alternative to Rider Requests

The Companies state that should Rider VBA be rejected on the grounds that it is administratively complex and burdensome, then they would propose deferred accounting in which:

> any Rider VBA revenues would be tracked in a deferred account until the Commission allows such amounts to be refunded to or recovered from customers through a charge or an adjustment to base rates. This could occur on an annual basis or in a future rate case proceeding. The Companies would propose that such amounts be refunded or recovered on an annual basis.

(North Shore/Peoples Gas Ex. VG-2.0, p. 50) In regard to Rider UBA, the Companies propose the same alternative if the Commission were to reject Rider UBA. (*Id.* p. 51)

For Rider EEP, GCI proposed a deferral accounting mechanism to track and reconcile differences between recovery and disbursements made by each utility for conservation programs, with the unspent balance in the deferral account evaluated and recognized in the next rate case to establish a revised ongoing recovery level in new base rates. (GCI Ex-MLB-1.0, pp. 72-73) The Companies indicated their acceptance of the proposal to use a deferred accounting approach to recover Rider EEP charges, but propose to recover such costs on an annual basis rather than waiting until the next rate case proceeding. (North Shore/Peoples Gas Ex. VG-2.0, p. 51)

The Companies proposals to use deferred accounting as an alternative to the rider recoveries proposed through Riders VBA, UBA and EEP, for later rate treatment either in subsequent rate cases or an annual adjustment to the base rates determined in this proceeding, should be rejected. Under "normal ratemaking procedures", a utility chooses a historical or future test year. (83 Ill. Adm. Code 287.20) Part 287 (83 Ill.

Adm. Code 287) contains the Commissions' test year rules. Section 287.20 defines the two test years that utilities may propose as either a historical or future test year. Section 287.30 promulgates when and how utilities can update their future test year data. Section 287.40 sets forth the requirements for pro forma adjustments to historical test years. The inclusion of non-test year "deferred" expenses in a subsequent test year rate filing as the Companies propose or the annual recovery adjustment would be contrary to the Commission's test year rules and the decision of the Illinois supreme court in *Business & Professional People for the Public Interest v. Illinois Commerce Comm'n*, 146 Ill. 2d 175; 585 N.E.2d 1032 (1991) ("BPI II"). (*See* ICC Staff Exhibit 13.0, pp. 16-18)

In BPI II, the Illinois supreme court addressed the issue of whether recovery of deferred charges was permissible. Several intervenors representing various ratepayer groups filed petitions with the court arguing that a Commission order which allowed ComEd to recover various deferred charges (depreciation expense, decommissioning expense and financial carrying costs) in its rates was in error. The intervenors argued that the order violated the Commission's test year principles as well as the rules against retroactive ratemaking and single-issue ratemaking. (*Id*. at 237) The court in BPI II found a fundamental difference between deferred depreciation expense, deferred decommissioning expense and deferred financial carrying costs and therefore, analyzed each category of expense separately with regard to test year principles. (*Id*. at 238) In its analysis, the court first looked to the nature of the deferred expenses. The court found deferred depreciation expense and deferred decommissioning expense to be operating expenses because they are treated as an operating expense for financial reporting purposes and, more importantly, for purposes of determining the revenue requirement. (*Id*. at 238-241) The court determined that deferred depreciation expense and deferred decommissioning expense were operating expenses which are subject to the Commission's test-year principles. The court held that allowing recovery of these operating expenses outside of the test-year violates test-year principles. (*Id*. at 240-241) As the Commission is well aware, "[t]he purpose of the test year rule is to prevent a utility from overstating its revenue requirement by mismatching low revenue data from one year with high expense data from a different year." (*Id*. at 237-238)

There is no issue in this proceeding that the costs related to Riders UBA and EEP that the Companies seek to defer and recover on an annual basis or in their next rate case are operating expenses and therefore test year items. Therefore, under BPI II, the Commission cannot allow them to be deferred or otherwise treat them as if they are not operating expenses. (*See* BPI II, 146 Ill. 2d at 240) As noted by the Company, its deferral proposal with respect to Rider VBA would involve the deferral of revenues. (North Shore/Peoples Gas Ex. VG-2.0, p. 50) The Rider VBA revenue deferral proposal would also violate the Commission's test year rules. As stated in BPI II:

> [A] utility's rates are a function of its **annual revenues and operating expenses, as well as its rate base**. In order to accurately determine the utility's revenue requirement, the Commission established filing requirements under which a utility must present its rate data in accordance with a proposed one-year test year. The purpose of the test-year rule is to prevent a utility from overstating its revenue requirement by **mismatching low revenue data from one year with high expense data from a different year**.

(BPI II, 146 Ill. 2d at 237-238 (emphasis added)) While none of the deferred charges at issue in BPI II involved a revenue charge, it is clear that the court determined whether each charge at issue was a test year item based on its relationship to the stated purpose of the rule -- to avoid a mismatching of **revenues** and **expenses**. As noted earlier, the court found deferred depreciation expense and deferred decommissioning expense to be operating expenses subject to test year principles. Deferred financing charges, on the other hand, were found not to be test year items since they had no impact on the potential mismatch of revenues and expenses:

> Under normal accounting procedures, the financing costs incurred prior to placing a plant in service are capitalized as AFUDC and amortized over the life of the plant. Thus these costs make up a portion of the depreciation expense allowed each year. However, carrying costs incurred after the plant is placed in service have consistently been treated differently for ratemaking purposes than have the pre-in-service financing costs. Under normal accounting procedures, post-in-service financing costs are neither expensed nor capitalized. **Instead, these costs are recovered through the rate of return authorized on the company's investment.** This is significant in that after a plant is placed in service, the related carrying costs are not treated as operating expenses in the revenue requirement formula.
>
> . . . .
>
> As previously stated, the test-year rules are intended to prevent a utility from mismatching revenue and operating expense data. Because the post-in-service carrying charges are not operating expenses, they are not test-year items.

(*Id*. at 242-243) The Rider VBA deferral request is a request to defer the so-called over- or under-collection of revenues, and as such is a test year item which cannot be recovered on a deferred basis.

The Commission itself has previously addressed the deferred charges issue subsequent to the court's ruling in BPI II and has acknowledged the limits placed on it by BPI II. In a rulemaking proceeding for deferred charges the Commission considered changing its rules for deferred charges in light of BPI II, but ultimately did not. No change was made because the Commission found that the deferral would violate BPI II. ICC Docket No. 93-0408, p. 13 (Order Oct. 19, 1994). In Docket No. 93-0408 various electric, gas and water utilities[34] within the state filed a petition seeking the initiation of a rulemaking for the purpose of promulgating a rule on recording and recovery of deferred costs. (*Id.* at 1) The proposed rule was to establish specific categories of costs and cost savings which entities subject to regulation by the Commission would be authorized to defer for future recovery or flow back to customers; establish procedures for obtaining, where necessary, authorization to defer such costs; and authorize the recovery of such deferred costs through tariffs approved by the Commission. (*Id.* at 1) The Commission accepted the utilities definition of deferred costs as items of expense or savings that would ordinarily be recognized as such in a given period, but which would be recognized at a future time. (*Id.* at 2) The proposed rule identified seven specific categories of costs that would be subject to deferred recording and recovery under the rule. The Commission concluded that the seven categories of costs proposed were either prohibited from recovery due to the test year problems identified in BPI II, subject to the single-issue ratemaking concerns raised in BPI II and therefore subject to some apportionment methodology such as the net income method; or already recoverable through methods currently utilized by the Commission. Because the costs were either prohibited or recoverable at present, the Commission found there to be no need for the proposed rulemaking.

The Commission was consistent in its treatment of requests for deferred expense in *Citizens Utilities Company of Illinois, d/b/a Citizens Water Resources Application for an Order Approving Deferred Accounting for Year 2000 Compliance Costs,* Docket No.

[34] The utilities filing the petition were: Central Illinois Public Service Company, Commonwealth Edison Company, Illinois-American Water Company, Illinois Power Company, Interstate Power Company, Iowa-Illinois Gas and Electric Company, Mt. Carmel Public Utility Company, North Shore Gas Company, the Peoples Gas Light and Coke Company, and Union Electric Company.

98-0895, 2000 Ill. PUC LEXIS 294 (March 15, 2000). In that case, the Commission found that

> The sole issue in this case is whether the Commission will allow deferral of expenses (other than those Y2K costs which have been capitalized) associated with Y2K preparations incurred over 1998 and 1999 beyond the years in which they were incurred. If this deferral is allowed, the Applicant may offset revenue in a future rate filing against these expenses. Under general rate making principles, only expenses incurred during the test year can be used to offset revenue accrued during that year.
>
> Although, the expenses appear to be reasonable and made in the public interest, they are not sufficiently large, or sufficiently unique, to justify special accounting treatment. The requested deferral would improperly match expenses from a non-test year with revenues from a test year. The requested deferral is contrary to the ratemaking principle requiring that expenses be recognized in the year in which they are incurred. Applicant is not barred from attempting to recover these costs in a separate rate-making proceeding, although that may not be convenient or practical.
>
> CUCI's arguments attempting to distinguish this situation from the holding in BPI II are not compelling. The two cases cited by CUCI as precedent for the proposition that Y2K expenses are recoverable were rate cases where, unlike this case, the costs were incurred during the test year. Clearly, the costs at issue are operating expenses. The Commission has previously recognized the applicability of BPI II to the question of deferral of operating expenses in ratemaking in Docket 93-0408. That recognition is dispositive of the issue in this proceeding.
>
> Therefore, we reject CUCI's Application to allow deferral of its Y2K operating expenses for ratemaking purposes.

(*Id*. at 9-10)

The Companies proposal to defer its revenues and costs is inappropriate for the same reasons set forth in the foregoing Commission orders. The Companies can seek recovery of those costs which are incurred during a test year; however, to allow the Companies to defer revenues or costs incurred outside of a test year to ultimately be recovered in a future rate case or annual proceeding is contrary to the holding in *BPI II*.

VIII. COST OF SERVICE

A. Overview

Please see the attached Appendix C for a comparison of Staff's and the Companies' conclusions on cost of service for each customer service classification at the Companies-proposed revenue requirements.

B. Embedded Cost of Service Study

1. Uncontested Issues

a. Functionalization of Intangible Plant Account Nos. 303.1 and 303.2

b. Classification of Distribution Plant Account No. 375

2. Contested Issues

a. Coincident Peak Versus Average and Peak Allocation Methods

The cost of service study the Companies used in developing their proposed rates allocated common distribution system costs, such as mains, according to coincident peak ("CP"). CP can be defined as distribution system costs are allocated according to the share of natural gas delivered to each customer service classification on the date that each Company (Peoples Gas and North Shore) delivers the highest total volume of natural gas combined for all customers. The theory behind CP allocation is that the distribution system must be sized to meet maximum demand; therefore, costs should be allocated to the customer service classifications based upon the share of demand on the date that natural gas deliveries are highest, because costs are increased to install additional capacity necessary to accommodate peak demand.

The flaw in CP allocation, however, is the inherent assumption that <u>all</u> distribution system costs are caused by additional installed capacity necessitated by natural gas deliveries on the date that natural gas volumes are greatest. As the Companies' own cost of service witness Ronald J. Amen explained, not all distribution system costs vary according to increased capacity. (North Shore Ex. RJA-1.0, pp. 25-26, lines 551-566; and Peoples Gas Ex. RJA-1.0, p. 25, lines 547-562) In fact, a significant amount of distribution system costs are not affected by the size of the distribution main, as expressed by the factor "b" in the North Shore and Peoples Gas cost equations and explanation provided by Mr. Amen. Staff rejects Mr. Amen's reason for introducing the cost equation, which is an attempt to show that distribution costs could be allocated, in part, according to customer count regardless of customer size, so that a Peoples Gas residential SC 1N customer with 9 therms of monthly usage would be allocated the same costs as a Large Volume Demand SC 4 customer with 71,933 therms of monthly usage residential SC 1N customer with 9 therms of monthly usage. Paradoxically, the cost equation provided by Mr. Amen demonstrates the inequity of fully allocating distribution system costs according to CP, even though the Companies proposed rates based upon CP.

Staff witness Luth recommends an Average and Peak (A&P) allocation of distribution system costs. A&P is superior to CP because A&P recognizes that distribution system costs are affected by, but are not entirely dependent upon, increased installed capacity. (ICC Staff Exhibit 7.0, p. 13, lines 246-255 and p. 15, lines 275-286) In addition to the share of deliveries on the peak date, A&P also takes into consideration average daily deliveries in allocating distribution system costs. (Id., p. 14, lines 256-274) As a result, the use of the distribution system on the 364 days of the year in addition to the peak date is also considered when allocating the costs of the distribution system under A&P. Since it makes sense that distribution system costs are not entirely based upon the size of the distribution system, as demonstrated by the Companies' witness Amen's testimony addressing the makeup of gas distribution system costs, the A&P allocation of a portion of distribution system costs according to average use throughout the year is reasonable and fair.

A&P may suffer from a misnomer. A&P could probably be re-named to Peak and Average so that it is not implied that average deliveries have greater influence on the allocation of distribution system costs than the share of deliveries on the peak date. (September 14, 2007 Transcript, p. 1482) For Peoples Gas and North Shore, A&P is weighted approximately 75 percent according to coincident peak and 25 percent according to average daily deliveries. (ICC Staff Exhibit 7.0, p. 14, lines 267-274) It is clear, therefore, from the weighting of coincident peak and average daily deliveries in the A&P formula, that the effect of costs from increased installed capacity is a significant factor in an A&P allocation in addition to average daily deliveries. Thus, A&P is a more reasonable balance and measure of allocating the costs of installed mains which are unaffected by increased capacity, and costs that are affected by increased capacity, as depicted in the equations provided by Peoples Gas and North Shore witness Amen.

Over the past decade, the Commission has consistently found that A&P allocation of distribution system costs is preferable to a CP allocation (September 14, 2007 Transcript, Tr., pp. 1484-1485), including: the most recent North Shore and Peoples Gas Orders (North Shore Order, Docket No. 95-0031, Order Dated November

8, 1995, pp. 33-36; Peoples Gas Order, Docket No. 95-0032, pp. 41-42); Nicor Gas' most recent rate case order (Docket No. 04-0779, Order Dated September 20, 2005), Illinois Power's 2004 request for increase in gas rates (Docket No. 04-0476, Order Dated May 17, 2005, pp. 64-66), CIPS' and UE's 2002 request for increase in gas rates (Docket Nos. 03-0008 and 03-0009, Order Dated October 22, 2003, p. 98), Nicor Gas' 1995 request for increase in gas rates (Docket No. 95-0219, Order Dated April 3, 1996) and CILCO's 1994 request for increase in gas rates (Docket No. 94-0040, Order Dated December 12, 1994). For the same reasons that the Commission has found that A&P allocation is preferable to a CP allocation over the past decade (September 14, 2007 Transcript, pp. 1484-1485), the Commission should conclude that distribution system costs should be allocated according to A&P rather than CP so that rates are based upon how the distribution system is used throughout the year, and not solely on the date of highest deliveries.

b. Classification of Uncollectible Account Expenses Account No. 904

c. Allocation of Costs to S.C. No. 1H and S.C. No. 1N

d. Allocation of Distribution Plant Account No. 385

e. Differentiated Class Rates of Return

f. Allocation of Revenue Requirement to Customer Classes

IX. RATE DESIGN

A. Overview

B. General Rate Design

1. Allocation of Rate Increase

2. Gas Cost Related Uncollectible Expense

Staff does not endorse Rider UBA proposed by North Shore Gas and Peoples Gas, and does not endorse the Companies' secondary position on how to include uncollectible gas costs in base rates. If the Commission does not authorize Rider UBA, the Companies favor an allocation of uncollectible gas costs similar to the approach the Companies took in developing Rider UBA. Part of the problem with Rider UBA and the Companies' alternative base rate proposal is the application of a uniform rate to determine the recovery of uncollectible gas costs from customer service classifications subject to Rider UBA, regardless of how each customer class adds to uncollectible gas costs. (ICC Staff Exhibit 19.0, pp. 16-17, lines 324-344) The result would be that some customer service classifications would pay more than the amount of uncollectible gas costs those customers add to uncollectible gas costs under Rider UBA or the Companies proposed alternative recovery of uncollectible gas costs through base rates, while other customer classes would pay less than the amount that those customer classes add to uncollectible gas costs. Since the gas costs and the uncollectible rate among SC 2 customers are different from gas costs and uncollectible rate among SC 1N and SC 1H customers, SC 2 sales customers should pay a different amount per therm for uncollectible gas costs than SC 1N and SC 1H customers. (ICC Staff Exhibit 19.0, Schedules 19.3-NS and 19.3-PG, line nos. 5, 10, and 14)

Sales customers in each customer service classification are supplied natural gas by North Shore or Peoples Gas, depending upon which company provides gas delivery service to the customer. Transportation customers obtain their own supplies of gas which are delivered by either North Shore or Peoples Gas. Sales customers, therefore, should pay for uncollectible gas costs, but transportation customers should not pay for uncollectible gas costs because North Shore or Peoples Gas do not provide gas supplied to transportation customers.

Staff witness Luth developed an uncollectible rate for each customer service classification that would result in the uncollectible rate for each customer service classification being applied to gas costs that each customer service classification is estimated to incur in the test year. (ICC Staff Exhibit 19.0, Schedule 19.3-NS and 19.3-PG) Thus, by developing a customer service classification-specific uncollectible rate, sales gas customers in each service classification would pay uncollectible gas costs that are based upon how customers in their own service classification affect uncollectible gas costs rather than how customers in other service classifications affect uncollectible gas costs. Staff demonstrated how the Companies' approaches yielded inconsistent results because a given customer service classification would pay different amounts for uncollectible gas costs, depending upon whether Rider UBA would be implemented or if uncollectible gas costs would be included in base rates. (ICC Staff Exhibit 19.0, pp. 16-17, lines 318-344)

The Commission should reject both the Companies' proposed Rider UBA, and proposed alternative approach to including uncollectible gas costs in base rates. The Commission should apply the calculations shown on Staff Schedules 19.3-NS and 19.3-

PG so that uncollectible gas costs are recovered from sales customers on a class-specific basis. The calculations shown on Schedules 19.3-NS and 19.3-PG would ensure that transportation customers in some customer service classifications do not overpay for natural gas delivery service while others pay less than the cost paid for natural gas delivery service compared to sales customers.

3. Other Rate Design Considerations

C. Service Classification Rate Design

1. Uncontested Issues

a. North Shore Service Classification No. 4

The Company proposed to change the title of this service from "Contract Service" to "Contract Service to Prevent Bypass" to be more descriptive. The Company also proposed to allow a contract to extend longer than the current maximum of five years in response to customer requests. The Company proposed a maximum of up to ten years. The Company also proposed minor editorial changes. (North Shore Ex. VG-1.0 3REV, p. 23) Staff witness Harden found these changes to Contract Service to be acceptable. As set forth in her testimony: (1) the changes are very minor with the exception of the change from a 5-year contract to a 10-year contract; (2) the increase in the length of the contracts would allow any costs that might be associated with the contracts to be spread out over a longer period of time and (3) a longer contract also saves the cost of the time it takes to negotiate a new contract between the parties. (ICC Staff Exhibit 9.0, p.6)

b. North Shore Service Classification No. 5

c. Peoples Gas Service Classification No. 5

The Company proposed minor editorial changes to Contract Service for Electric Generation. (Peoples Gas Ex. VG-1.0 2REV, p. 26) Staff accepted these reasonable changes to Contract Service for Electric Generation. (ICC Staff Exhibit 9.0, p.6)

d. North Shore Service Classification No. 6

The Company proposed minor editorial changes to Contract Service for Electric Generation. (North Shore Ex. VG-1.0 3REV, p. 24) Staff accepted these reasonable changes to Contract Service for Electric Generation. (ICC Staff Exhibit 9.0, p.6)

e. Peoples Gas Service Classification No. 6

f. Peoples Gas Service Classification No. 8

2. Contested Issues

a. Peoples Gas Service Classification Nos. 1N and 1H

Peoples Gas proposed to bifurcate the present residential service classification ("SC") 1 into SC 1N and SC 1H. The distinction would be based upon the use of natural gas at the residential customer's service address. More specifically, the distinction is based upon for what use the natural gas is being used for. That is, is it being used for heat or non heat. SC 1N would apply to residential customers who do not use natural gas for space heating purposes, while SC 1H would apply to residential customers who use natural gas for space heating purposes. Company-proposed rates under SC 1N would offer an $11.25 per month customer charge that is lower than the

$19.00 per month customer charge under SC 1H, but a 49.77¢ per therm single, or flat-block usage charge, that is higher than the declining two-block usage charges of 35.220¢ and 10.768¢ per therm under SC 1H.[35]

Staff does not necessarily oppose the separation of residential customers according to usage, but the separation should be based upon volume, i.e., low usage vs. higher usage. In many, if not most cases, Staff's proposed separation would have the same end result as the Companies proposal based upon how natural gas is used (i.e. Heat or Non Heat) because space heating typically requires far more natural gas than non-space heating uses. However, if a non-space heat customer uses sufficient volumes of natural gas that a billing under SC 1N would exceed a billing under SC 1H, the non-space heat customer should not be forced to pay more than a SC 1H customer with comparable usage simply because the non-space heat customer does not use natural gas for space heating. If anything, the relatively high-use non-space heating customer should pay less than the heating customer for the same usage because the load profile for the non-heating customer should be expected to be more constant, thereby minimizing the need for extra capacity costs for service during demand peaks. (ICC Staff Exhibit 19.0, p. 9, lines 172-177)

Staff's solution to non-space heating customers possibly qualifying for SC 1H rates is for the customer to be given a choice whether to be billed during the off-peak, summer months under SC 1N or SC 1H. (Id., pp. 9-11, lines 181-214) Customers

[35] At Company-proposed revenue requirement and assumes Rider UBA is rejected by the Commission. Rates would be lower under a Commission-approved revenue requirement that is lower than the Company-proposed revenue requirement. Commission approval of Rider UBA would lower usage charges, but customers would be charged an additional amount per therm under Rider UBA which would fluctuate from month-to-month.

should be advised of the opportunity to change how they will be billed for the next 12 months, with the further advisement that the choice will remain in effect until the following June 15th. The Company would provide generic information to the customer to consider in making the choice between SC 1N and SC 1H, such as the break-even point for monthly usage where SC 1N billing becomes more expensive than SC 1H billing, and for the customer to consider how natural gas will be used over the next October 15th through June 15th.

If the administrative challenge of providing residential customers a choice between SC 1N and SC 1H billing is overly burdensome to the Company, then cost of service and billing unit information for the proposed SC 1N and SC 1H customer classes should be combined to develop a set of rates for an SC 1 customer class. Currently, residential non-space heating and space heating customers are subject to the same rates for the same usage, so combining the two types of customers would not represent a change in how those customers are billed. At the Company-proposed revenue requirement, the lower customer charges with UBA suggested by Company witness Grace are acceptable to Staff if the proposal to separate SC 1N and SC 1H customers with UBA is rejected by the Commission. (North Shore/Peoples Gas Ex. VG-3.0, p. 12, table preceding line 247) Staff does not support Rider UBA, but it is not reasonable that a customer charge without Rider UBA would be higher than if Rider UBA is authorized by the Commission. The proposed Rider UBA is a per-therm charge, so the lack of Rider UBA should affect usage charges, but not the customer charge.

If the Commission approves the separation of residential customers into SC 1N and SC 1H, Staff recommends rates based upon Staff's cost of service study. Staff proposed rates would result in a subsidy from SC 2 customers of approximately $9.94 million, which means that SC 1N and SC 1H customers would pay a combined $9.94 million less than cost of service at the Company-proposed revenue requirement. Under Company-proposed rates, SC 1N and SC 1H customers would pay $20.1 million less than cost of service at the Company-proposed revenue requirement, which would require a larger amount above cost of service from SC 2 customers. Staff is sensitive not only to rate increases affecting customers, but also the amount customers pay relative to cost of service. Thus, since SC 2 is being asked to pay for SC 1N and SC 1H costs in addition to SC 2 costs, SC 2 revenues above SC 2 costs should be minimized despite SC 1N and SC 1H revenues that would average approximately 44¢ per therm for delivery.

The following table compares SC 1N and SC 1H rates proposed by the Company and Staff at the Company-proposed revenue requirement and assuming no Rider UBA:

SC 1N	Staff[36]	Company[37]	Difference
Customer Charge	$ 12.00	$ 11.25	$ 0.75
Sales Usage Charge (all therms)	$0.48845	$ 0.49447	$ (0.00602)
Transportation Usage Charge (all therms)	$0.43800	$ 0.39989	$ 0.03811

[36] Source for Staff rates: ICC Staff Exhibit 19.0, Schedule 19.1-PG, page 1 of 11 for Sales Rates, page 5 of 11 for Transportation Rates

[37] Source for Company rates: North Shore/Peoples Gas Exhibit 2.4-PGL, page 1 of 8 for Sales Rates, page 2 of 8 for Transportation Rates

SC 1H	Staff	Company	Difference
Customer Charge	$ 19.00	$ 19.00	$ 0.00
Sales Usage Charge (First 50 therms)	$0.36447	$ 0.35220	$ 0.01227
Transportation Usage Charge (First 50 therms)	$ 0.33518	$ 0.29862	$ 0.03656
Sales Usage Charge (Over 50 therms)	$ 0.11517	$ 0.10768	$ 0.00749
Transportation Usage Charge (Over 50 therms)	$0.08588	$ 0.09131	$ (0.00543)

b. North Shore Service Classification Nos. 1N and 1H

The following table compares North Shore SC 1N and SC 1H rates proposed by the Company and Staff at the Company-proposed revenue requirement and assuming no Rider UBA:

SC 1N	Staff[38]	Company[39]	Difference
Customer Charge	$ 10.50	$ 10.50	$ 0.00
Sales Usage Charge (all therms)	$0.33970	$ 0.34064	$ (0.00094)
Transportation Usage Charge (all therms)	$0.31033	$ 0.28700	$ 0.02333

[38] Source for Staff rates: ICC Staff Exhibit 19.0, Schedule 19.1-NS, page 1 of 8 for Sales Rates, page 4 of 8 for Transportation Rates

[39] Source for Company rates: North Shore/Peoples Gas Exhibit 2.4-NSG, page 1 of 8 for Sales Rates, page 2 of 8 for Transportation Rates

SC 1H	Staff[2]	Company[3]	Difference
Customer Charge	$ 16.00	$ 16.00	$ 0.00
Sales Usage Charge (First 50 therms)	$0.24541	$ 0.24821	$ (0.00280)
Transportation Usage Charge (First 50 therms)	$ 0.24055	$ 0.23617	$ 0.00438
Sales Usage Charge (Over 50 therms)	$ 0.06398	$ 0.06658	$ (0.00260)
Transportation Usage Charge (Over 50 therms)	$0.05912	$ 0.06335	$ (0.00423)

c. Peoples Gas Service Classification No. 2

d. North Shore Service Classification No. 2

e. North Shore Service Classification No. 3

f. Peoples Gas Service Classification No. 4

g. Peoples Gas Service Classification No. 7

While this issue is in the contested section of the outline it is uncontested between Staff and the Company. The Company proposed to change the title of this service from “Contract Service” to “Contract Service to Prevent Bypass” to be more descriptive. The Company also proposed to allow a contract to extend longer than the current maximum of five years. The Companies propose a maximum of up to ten years. The Companies also proposed minor editorial changes (Peoples Gas Ex. VG-1.0 2REV, p. 27) Staff witness Harden found these changes to be acceptable. As set forth in her testimony: (1) the changes are very minor with the exception of the change from a 5-year contract to a 10-year contract, (2) the increase in the length of the contracts would allow any costs that might be associated with the contracts to be spread out over a longer period of time and (3) a longer contract also saves the cost of the time it takes to negotiate a new contract between the parties. (ICC Staff Exhibit 9.0, p.6)

D. Tariffs – Other Tariff Issues

1. Rider 2, Factor TS

The Companies proposed changes to Rider 2 to reflect the applicability of the rider based on their proposal to eliminate and rename applicable transportation riders. (North Shore Ex. VG-1.0 3REV, p. 31 and Peoples Gas Ex. VG-1.0 2REV, p. 35) The proposed changes that refer to other riders are appropriate if the Commission approves the elimination and renaming of certain transportation riders. (ICC Staff Exhibit No. 9.0, p. 25)

The Companies' propose to eliminate Factor TS – Transition Surcharge, and refund or recover any dollars awaiting recovery or refund through Factor NCGC – Non-Commodity Gas Charge. (North Shore Ex. VG-1.0 3REV, p. 31 and Peoples Gas Ex. VG-1.0 2REV, p. 35) Staff recommends the Commission approve the Companies' proposed elimination of Factor TS language in Rider 2 if the Commission approves Staff's recommendation to roll Factor TS balances into their non-commodity gas charges. (ICC Staff Exhibit 21.0, p. 10)

Rider 2 also reflects minor editorial changes to clarify language and pursuant to the Commission's Order in Docket No. 06-0540, reflects the change to a calendar year for its fiscal year. (North Shore Ex. VG-1.0 3REV, pp. 31 – 32 and Peoples Gas Ex. VG-1.0 2REV, pp. 35 - 36) In Docket No. 06-0540, the merger case between Peoples Gas and North Shore, the Companies requested approval to change reconciliation years in the Gas Companies' Riders 2 and 11 to calendar year bases. The Commission approved the request at page 64 of its Final Order in that docket. (ICC Staff Exhibit 9.0, p. 24)

2. Charge for Dishonored Checks and/or Incomplete Electronic Withdrawal

The Companies propose to increase the fee for Dishonored Checks and Incomplete Electronic Withdrawal from $10 to $25. (North Shore Ex. VG-1.0 3REV, pp. 28 - 29 and Peoples Gas Ex. VG-1.0 2REV, pp. 32 - 33) Staff agrees with the Companies that the proposed increase in revenues from this fee will offset the increase in base rates in this proceeding and that MidAmerican Energy Company has raised the same fee to $25 as well, which the Commission approved in ICC Docket No. 99-0534. (ICC Staff Exhibit 9.0, pp. 10-11). Staff witness Harden further testified that she agreed with the Commission's argument in the MidAmerican case that the increase in the fee would discourage customers from writing bad checks. (Id., p. 11)

3. Rider 4, Extension of Mains

Under the Companies proposal, the basic structure of Rider 4 is unchanged as it delineates the Companies and customer responsibilities. The Companies proposed language changes for Rider 4 clarifies current practices and customers preferences for example, if a customer wanted to install a main in a different location than is required to provide service to the customer, the customer would bear the costs to meet the customer's preference. (North Shore Ex. VG-1.0 3REV, p. 32 and Peoples Gas Ex.

VG-1.0 2REV, p. 36) While certain language changes were acceptable other changes caused Staff witness Harden concern.

The proposed language that concerned Staff was the following:

> If a customer requests the Company to install, relocate or replace a gas main or mains in addition to or in a manner other than what is required for the Company to provide service, including installations on private property such as private drives, the customer shall pay the Company's costs of installation, relocation or replacement. Such costs include, but are not limited to, labor costs, material costs, transportation costs, overheads and return. For the purposes of this rider, "return" is defined to mean the pre-tax rate of return approved by the Commission in the Company's most recent rate case proceeding.

Staff witness Harden found the proposed language to be very broad and that it refers to charging customers, with no limit, for labor costs, material costs, transportation costs, overheads and return. Staff requested additional support and/or explanation for proposed language changes to Rider 4. (ICC Staff Exhibit 9.0, pp. 26-27) Staff was not satisfied by the additional information in the Companies' Rebuttal testimony (North Shore/Peoples Gas Ex. VG-2.0, p. 53) and continued to object to the proposed language of a "return" being charged to customers through Rider 4. (ICC Staff Exhibit 21.0, p. 5) In Surrebuttal testimony the Companies agreed to remove the "return" language from the Rider. (North Shore/Peoples Gas Ex. VG-3.0, p. 29) With the removal of "return" from the proposed language Staff's prior concerns were satisfactorily addressed.

4. Rider 5, Gas Service Pipe

The Companies proposed to reduce the amount of free gas service pipe from 100 feet currently to 60 feet as agreed by Parties in Docket No. 03-0767. (North Shore

Ex. VG-1.0 3REV, p. 33 and Peoples Gas Ex. VG-1.0 2REV, p. 37) While the Commission's Order on Rehearing in Docket No. 03-0767 dated April 5, 2006, did not adopt the Parties Agreement, Staff can recommend approval of the proposed change since it is consistent with 83 Ill. Adm. Code 500.310 *et seq*…" Section 500.310 of Part 500 (83 Ill. Adm. Code 500.310) does not specify an amount of free length of service connection only that it not exceed 100 feet. (ICC Staff Exhibit 9.0, pp. 27-28) Given that the 60 feet is consistent with the parties agreement, Staff finds the change acceptable.

The Companies also specify assessed charges for disconnecting and relocating service pipe. (North Shore Ex. VG-1.0 3REV, p. 33 and Peoples Gas Ex. VG-1.0 2REV, p. 37) Staff requested additional support and/or explanation for proposed language changes to Rider 5 pertaining to a "return" being charged to a customer and the 2-year timeframe for disconnection/reconnection charges. (ICC Staff Exhibit 9.0, p. 29) Staff accepted the Companies explanation for the 2-year time frame (North Shore/Peoples Gas Ex. VG-2.0, pp. 54-55) but was not satisfied by the additional information in the Companies' Rebuttal testimony in regards to a "return" being charged to customers. (North Shore/Peoples Gas Ex. VG-2.0, p. 54) Staff continued to object to the proposed language of a "return" being charged to customers through Rider 5. (ICC Staff Exhibit 21.0, p. 6) In Surrebuttal testimony the Companies agreed to remove the "return" language from the Rider. (North Shore/Peoples Gas Ex. VG-3.0, p. 29) With the removal of "return" from the proposed language Staff's prior concerns were satisfactorily addressed.

5. Rider 8, Heating Value of Gas Supplied -- Monthly Filing

The Companies proposed changes to Rider 8 to reflect the applicability of the rider based on their proposal to eliminate and rename applicable transportation riders. (North Shore Ex. VG-1.0 3REV, p. 33 and Peoples Gas Ex. VG-1.0 2REV, p. 37) The proposed changes that refer to other riders are appropriate if the Commission approves the elimination and renaming of certain transportation riders. (ICC Staff Exhibit No. 9.0, p. 30)

In rebuttal testimony (ICC Staff Exhibit 21.0, pp. 6-8) Staff discussed the proposed revision by the Companies to make filings regarding the heating value factor only when the heating value factor changes, rather than every month, which is the existing practice. The heating value factor is discussed in Administrative Code Section 500.280 Heating Value and Calorimeter Equipment which, in part, states:

> Each utility furnishing natural gas, liquified petroleum gas or a mixture of such gases with manufactured gas shall maintain in each community or territory served by it a monthly average standard of heating value of gas authorized by the Commission for that utility and community. Such standard of heating value shall be maintained with as little deviation as practicable, and the average total heating value on any one day shall not exceed or fall blow the authorized monthly standard by more than five percent. (83 Ill Admin. Code, Section 500.280(a)(1)

The Companies currently file an information sheet and calculation sheet(s) showing any Btu adjustment that may be necessary each month. This monthly filing gives assurance to the Commission that the heating value factor numbers have been reviewed by the Companies each month and that the standard heating value, as discussed above, is being maintained. The Companies' proposed tariff language change is a simple wording change from "each" month to "a" month. Staff does not recommend that it be approved by the Commission. Similarly, Staff does not recommend approval of the proposed addition of the phrase "<u>and remain in effect until superseded by a subsequent filing pursuant to this rider</u>."

The basis for Staff's position is that if a filing is only required when there is a change in the heating value, that does not provide the same assurance to the Commission that heating value factors are being reviewed each month. If several months go by and no filing is made, the Commission has less assurance that the Companies are reviewing heating value factors; whereas if a filing is made each month, then the Commission receives assurance that the heating value factors have, in fact, been reviewed by the Companies. (ICC Staff Exhibit 21.0, pp. 6-8) The Companies did not provide a response to Staff's concerns about the monthly filing in its surrebuttal testimony therefore; Staff does not know whether this is a contested issue.

6. Elimination of Riders 12, 13, 14, 15, CCA, and LCP

The Companies proposed to eliminate People Gas' Rider 13 – Remote Meter Reading Devices; North Shore Rider 14 and Peoples Gas' Rider 15 – Taxes on Use of Compressed Natural Gas; Peoples Gas' Rider LCP – Low Income Customer Assistance Program; and both Companies proposed to eliminate Rider CCA – Customer Charge Adjustments. Staff agreed with the proposed eliminations of Riders 13, 14, 15, CCA and LCP. The tariff language from North Shore Rider 14, Peoples Gas Rider 15 and Rider CCA has been combined into Rider 1. Peoples Gas Rider 13 and Rider LCP are proposed to be completely eliminated. (ICC Staff Exhibit 9.0, p. 16-22)

7. Miscellaneous Changes to Riders 1, 3, [9], 10, and 11

The Companies proposed miscellaneous changes to Rider 1 – Additional Charges for State and Municipal Utility Taxes, Rider 3 – Budget Plan of Payment, Rider 10 – Controlled Attachment Plan and Rider 11 – Adjustment for Incremental Costs of Environmental Activities. The changes include changing the title of the rider, adding language from proposed elimination of other riders, a change in the calendar year, converting language to a number formula and changes for consistency with other tariffs or practices and to make the language more understandable. Staff recommends approval of the changes to Rider 1, 3, 10 and 11. (ICC Staff Exhibit 9.0, p. 22-32)

The Companies also proposed changes to Rider 9 to reflect the applicability of the rider based on their proposal to eliminate and rename applicable transportation riders. (North Shore Ex. VG-1.0 3REV, p. 34 and Peoples Gas Ex. VG-1.0 2REV, p. 37) The proposed changes that refer to other riders are appropriate if the Commission approves the elimination and renaming of certain transportation riders. (ICC Staff Exhibit No. 9.0, p. 31)

X. TRANSPORTATION ISSUES

A. Overview

B. Uncontested Issues

1. Demand Diversity Factor

2. Daily Demand Measurement Device Charge

3. Elimination of Rider TB (NS)

4. Revised Calculation of Average Monthly Index Price

5. Administrative Charges for Rider SST and Rider P

6. Elimination of 120 Day Meter Read Requirement for CFY Enrollment

7. Meter Reading

Staff raised a concern regarding the effectiveness of Peoples Gas' meter reading program due to the number of unread meters, including a meter that had gone unread for over 11 years. (ICC Staff Exhibit 23.0, p. 21) Staff recommended that Peoples Gas provide quarterly updates to the Director of the Energy Division and the Director of the Consumers Services Division that summarized the number of consecutively unread meters without a reading for more than six months with the first report showing the meter reading status as of March 30, 2008 and that this reporting requirement continue for a minimum of two years. (Id., p. 23) Staff also requested that Peoples Gas provide these reports within 30 days after the end of each quarter. (Id.) Finally, Staff requested that Peoples Gas, when applicable, provide an explanation of any reason why the number of consecutively unread meters increased during the reporting period and what Peoples Gas is doing to further reduce those values. (Id.) Peoples Gas agreed to Staff's proposal. (North Shore/Peoples Gas Ex. ED-3.0, pp. 3-4)

8. Automatic Meter Reading

Staff raised a concern with Peoples Gas' policy regarding the amount of time it waited prior to addressing potential ert[40] device problems. (ICC Staff Exhibit 23.0, pp. 23-34) Staff recommended that Peoples Gas provide quarterly updates to the Director of the Energy Division and the Director of the Consumers Services Division that summarized the number of consecutively unread erted meters that have not obtained a reading for three months with the first report showing the meter reading status as of March 30, 2008 and that this reporting requirement continue for a minimum of two years. (Id., pp. 25-26) Staff also requested that Peoples Gas provide these reports within 30 days after the end of each quarter. (Id., p. 26) Finally, Staff requested that Peoples Gas provide an explanation for any reasons it discovered for unread meters that need correcting to obtain a higher percentage of reads, as well as an explanation, if applicable, of any reason why the number of consecutively unread erted meters increased during the reporting period and what Peoples Gas is doing to reduce those values. (Id.) Peoples Gas agreed to Staff's proposal. (North Shore/Peoples Gas Ex. ED-3.0, p. 4)

[40] An ert refers to one type of device that is attached to a meter to allow for remote reading (aka automatic meter reading ("AMR")) of the meter's usage. (Staff Ex. 11.0, p. 35)

9. Billing Demand Determination

10. Imbalance Trading

C. Large Volume Transportation Program

1. Rider FST

Staff as set forth in its rebuttal testimony did not oppose phasing out Rider FST. (ICC Staff Exhibit 24.0 Corrected, p. 14) Staff took that position because it believed that, with the right adjustments to Rider SST, Rider FST was no longer needed. (Id.) However, in Zack's Surrebuttal testimony (North Shore/Peoples Gas Ex TEZ 3.0_REV, p. 4), the Companies offered to retain Rider FST subject to certain modifications. The Companies call their alternative proposal "Alternative Rider FST". One modification is a cap on daily nominations to limit storage injections. The caps would apply in both summer and winter. The Companies propose a daily nomination cap equal to the customer's average daily use in the "comparable month" of the prior year plus 0.67% (20% divided by 30) of the customer's AB.[41]. (Id., p. 5) The Companies also propose to incorporate the seasonal restrictions supported by Commission Staff. Companies witness Zack also believes that the seasonal restrictions are acceptable to Vanguard as well. (Id.) Companies' witness Zack also proposes other edits to Rider FST to align it with the general changes to the transportation riders it is seeking in this docket. This encompasses various issues like definitions of terms and applying the diversity factor to the new Rider FST. (Id., pp. 5-6)

These modifications are a reasonable compromise between the desire for flexibility on the marketers' part and the Companies' ability to balance their systems at

[41] "Comparable month" is not defined. Staff recommends that the Commission order this term be defined as the same month from the prior year.

reasonable cost, therefore Staff does not object to retaining Rider FST with these changes. In addition, in light of these changes to FST Staff believes it is reasonable to keep a demand meter for existing Rider SST who currently have a demand meter even though Staff witness Rearden testified that there should not be daily metering. (ICC Staff Exhibit 24.0 Corrected, p. 15; September 11, 2007 Transcript, Tr., p. 694) Staff's reasoning for this position is discussed in the daily metering requirements section of this brief.

2. Rider SST

For Rider SST, the Companies proposed formulas that strictly limited injections and withdrawals from the allowable Bank ("AB") relative to currently existing Rider SST (ICC Staff Exhibit 24.0 Corrected, p. 5) Under existing Rider SST, customers can inject up to their Maximum Daily Quantity ("MDQ") on non-Critical days and only for Supply Shortage Days are there limits on the withdrawals that customers can make. The limits which are constant over all months are based on the amount of gas that a customer can bank and the standby percentage selected by the customers. Injections are restricted during Supply Surplus Days, in which the limit is the selected backup percentage times. (Id.) The new formulas are complex and vary by month in order to align the services provided to transportation customers with the Companies' underlying storage services. The parameters determine the maximum daily injection quantity attributable to base rate and gas charge storage by month. Similarly for withdrawals, a formula limits withdrawals using monthly parameters based upon base rate and gas charge storage. These parameters generated an annual profile of injections and withdrawals that attempts to track the utilities' own storage usage during the year. The stated intent is to meet the limitations that the Company itself faces. (Id., pp. 5-6)

Staff does not support the Companies' proposed monthly limits on storage injections and withdrawals by transportation customers. The Companies witness Zack did not demonstrate that transportation customers are cross-subsidized by sales service customers. Staff witness Rearden found the Companies' proposal as too restrictive and inconsistent with providing choices for customers. For all these reasons, Staff recommends that the Commission reject these proposed changes. Additionally, Staff would add that the Companies have adequate tools to make their transportation and sales offerings work effectively without imposing these customer restrictions (Id., p. 9) such as the ability to declare Critical Days to restrict customers' injection and withdrawal right to ensure that they can balance their systems. (Id., pp. 10-12)

3. Daily Metering Requirements

Staff took the position that the requirement for a demand meter in Rider SST should be eliminated. As set forth in Staff witness Rearden's testimony, Staff recommended eliminating the requirement for a number of reasons. First a customer should not be precluded from flexibly using storage simply because it does not have a demand meter. Second, a demand meter's cost is significant. A Rider FST customer that transitions to Rider SST bears higher costs of more than $300 per year, according to Oroni and Rozumialski. In addition, their testimony claims that if the phone line is included, the cost increase becomes closer to $1000 per year. (CNE-Gas Ex. 1.0, p. 28) This is an important factor for smaller customers. Third, besides being a significant cost deterrent to smaller customers taking SST, the meter is not needed from a system standpoint. The Companies could estimate usage for small transportation customers when they determine delivery levels for that customer, just as they do now. Also, the difference between the estimated daily usage and customer deliveries can be used as storage activity, just as is done now. (Rearden Rebuttal 293-305)

However, the Companies have agreed to retain and modify Rider FST with an Alternative Rider FST, that does not require a demand meter. So the requirement for a demand meter for Rider SST customers does not increase burdens on customers switching to Rider SST from Rider FST, since Rider FST is retained, although modified. While Staff still believes that Peoples Gas does not need to require a demand meter for Rider SST customers, (September 11, 2007 Transcript, Tr., p. 684) the requirement does not adversely affect existing Rider SST customers, since they already have one. And there are no negative rate impacts imposed on Rider FST customers, since they are not forced to switch to Rider SST.. Only those customers that voluntarily switch Rider SST are required to pay for a demand meter since the Companies agree to retain Rider FST.

4. Injection, Withdrawal and Cycling Requirements

In Staff's opinion, the most contested and important issue between the marketers and the Companies is the marketers demand for better access to storage services than the Companies propose in their tariffs. The Companies use flowing gas, leased transportation and storage services and Manlove Field to provide storage and balancing services to marketers, Hub customers and its bundled sales service customers. The

Companies must allocate its assets between the three customer groups in an equitable and efficient manner while recognizing each customer group's individual load profile, demands and economic incentives. This is a complex and difficult task with no simple and obvious ways to allocate the Companies' resources among the three customer groups. If the Companies grant one group a right to use limited system resources, then that right is not available to the other groups. The Companies believe that the marketers currently have too much freedom over their storage services, so they proposed methods to restrict that freedom. (ICC Staff Exhibit 24.0 Corrected, pp. 3-4)

The Companies are concerned that the transportation tariffs grant too much storage usage flexibility to transportation customers at the expense of retail sales customers. As a result, the Companies argue that sales service customers cross-subsidize transporters. Staff agrees that on a theoretical, mathematical level, under some conditions, it is **conceivable** that sales service customers **could** subsidize transporters. However, Companies witness Zack concludes that sales service customers **do** subsidize transporters under current rules. The Companies do not prove their case, and they do not estimate aggregate transfers from sales customers to transportation customers. (Id., p. 9)

Staff's position is that transportation customers and their marketers should be encouraged to cycle their storage. Several of the Companies' leased storage agreements feature injection and withdrawal restrictions in their tariffs. Staff concurs with the Companies' proposal to initiate a seasonal cycling provision into the tariff. However, Staff recommends that the Commission reject the Companies' proposed monthly restrictions on transportation customers' storage usage. Staff believes that this represents a fair compromise between what the Companies want to do and marketers desire for no additional restrictions at all. (Id., p. 12)

Staff recommends that the Companies' proposed restrictions on storage usage be simplified by eliminating various restrictions. Staff's alternative proposal is to retain the existing formulae with respect to limits on injections and withdrawals. However, Staff agrees with the Companies that Rider SST should be amended by adding end of season restrictions on storage balances. These restrictions force transport customers of Peoples Gas and North Shore to fill their allowable banks to 70% and 85%, respectively by the end of November and to draw down the allowable bank to 35% and 24%, respectively by the end of March. (Id., pp. 14-15)

5. Unbundled Storage Bank ("USB")

IIEC witness Rosenberg proposes that the Companies offer a storage service in addition to their standby services. He calls it the Unbundled Storage Bank ("USB"). The capabilities and costs of the USB would depend upon Manlove Field's characteristics. Dr. Rosenberg calculates the total number of days of allowable bank based upon coincident peak and total Manlove Field capacity. He estimates a diversity factor to correct for when storage usage by marketers is coincident with the system storage usage. Cost per unit is total cost divided by total capacity. (ICC Staff Exhibit 24.0 Corrected, pp. 12-13)

The Companies recommended that the Commission reject the proposal. Companies witness Zack provides several reasons. He contends that it over-estimates the availability of Manlove Field and under-estimates the costs. He further notes that when the Companies' provide storage services to transportation customers, the services are based upon leased storage services as well as Manlove Field. (Id., p 13)

Staff also recommends that the Commission reject the USB. The storage available to transport customers should reflect the availability of all storage resources that the Companies own or lease, not just the storage that has the lowest cost. The Companies operate their system as a whole. They supply the gas consumed by customers with deliveries from interstate pipelines, storage services and Manlove Field. It is inequitable to allocate the lowest cost storage asset to one group before others. While the USB would certainly benefit transportation customers, it achieves that benefit by a direct allocation of Manlove Field to transport customers. That necessarily implies that the other customer groups must pay rates that result from the use of higher cost resources. (Id., pp. 13-14)

6. Rider P-Pooling

a. Pool size limits

A customer pool is an aggregation of a supplier's transportation customers for the purposes of balancing demand and supply and avoiding penalties for its customers. There is Rider P for pooling SST customers and Rider AGG for pooling CFY customers. Pooling makes it easier for suppliers to balance supply and demand. Suppose, in a given month, a marketer brings in more gas than one of its customers has used. And the same marketer, in the same month, has supplied less than another of its customers has used. Then the supplier can use the excess supply from the first customer to balance out the shortage from the second customer in order to avoid or reduce penalties from over- or under-supply and vice versa. The pools provide economies to marketers that can result in lower prices for their customers. (ICC Staff Exhibit 24.0 Corrected, p. 20)

CNE-Gas proposes to eliminate pool size limits altogether. (CNE-Gas Ex. 1.0, 382-414) Vanguard, on the other hand, supports an increase in pool size to 300 customers. (Vanguard Ex. 1, pp. 5-6) The Companies object to raising the pool size limit above 200 customers, because pools should be limited "…for administrative and billing system reasons." (North Shore/Peoples Gas Ex. TZ-2.0, p. 35, line 771) Companies witness Zack notes that the pool cannot bill until all the sub-accounts are billed. If a billing exception occurs, manual intervention is required, which delays the pool's bill. According to Mr. Zack, allowing larger pools raises the probability that a given pool's billing will be subject to manual intervention and delayed pool bills. The Companies propose a pool limit of 200 to limit rebilling problems for pool sizes over 200. Companies witness Zack also points out that few pools approach the current limit of 150. (Id., pp. 35-36; ICC Staff Exhibit 24.0 Corrected, pp. 20-21)

Staff does not believe that the Companies' reasons are persuasive. The charges for pooling service should account for all the costs to provide the services. The Companies do not demonstrate that the costs for pools above 200 are necessarily much higher than for pools below that level. Large pools may instead reduce the number of pool rebills by reducing the number of pools. And the Companies do not provide the number of re-bills or how long they delay pool bills or the subsequent costs that those delays impose on customers. In the end, tracking a pool's activity is an accounting function, and it should not be expensive to aggregate customers' activities. (ICC Staff Exhibit 24.0 Corrected, p. 21)

b. "Super-pooling"

Witnesses John M. Oroni and Lisa A. Rozumialski for Constellation NewEnergy-Gas Division ("CNEG") define super pooling as a pool of pools and individual standalone customers that are under common management. (CNEG Ex. 1.0, p. 20) The Companies oppose super pooling for a number of reasons. Companies witness Zack states that, "…the Utilities would need to make significant modifications to the billing system." (North Shore/Peoples Gas Ex. TZ-2.0, p. 36) He also states that there are also significant details in the proposal that need to be clarified, including how to allocate imbalances and imbalance charges between pools and customers if a 'super pool' goes out of balance. (*Id*., pp. 36-37)

In their Rebuttal Testimony, CNE-Gas witnesses Oroni and Rozumialski offered a method to account for imbalance charges across pools and single customer groups. (CNE-Gas Exhibit 2.0, pp. 16-17) CNE-Gas witnesses Oroni and Rozumialski also consent to, if the alternative is no super-pool at all, using super-pools only to test end of season restrictions, Supply Surplus Days and Critical Days. (Id., 10-11) But these witnesses continue to argue that stand-alone customers should be allowed to be included in any super-pool.[42] (Id., 12-14) At the same time, Vanguard is willing to exclude standalone customers from the super-pool, although its preference is to include

[42] One substantive objection to including standalone customers in a super-pool is when it takes supply from more than one supplier. CNE-Gas witnesses Oroni and Rozumialski propose that such customers be excluded from super-pools. (CNE-Gas Ex. 2.0, 13-14)

them. (Vanguard Ex. 3, p. 4) Further, Vanguard is also amenable to using super-pools for the seasonal cycling requirements only. (Id., pp.3-4) In its surrebuttal, the Companies agreed to implement super-pooling only for the purposes of the seasonal restrictions and only if stand-alone customers are excluded. (NS-PGL Ex. 3.0 REV, 306-391)

Staff has concerns about super-pooling in general at this time. (ICC Staff Exhibit 24.0 Corrected, pp. 21-22) However, since the Companies apparently believe that super-pooling for end of season restrictions is feasible and are willing to accept it, then Staff does not oppose it.

c. Permitting Customers With Different Selected Standby Percentages ("SSP") to Be in the Same Pool

7. Operational Issues

a. Intra Day Allocations and Intra Day Nominations

b. Delivery Restrictions

8. **Other Large Volume Transportation Issues**

a. **Accounting for Trading and Storage Activity**

b. **Excess Bank and Critical Surplus Day Unauthorized Overrun Charges**

c. **Cash-outs Index**

d. **Receipt of Service Classification, Rider, AB, MDQ, and SSP Information**

D. Small Volume Transportation Program (Choices for You^{SM} or "CFY")

1. Storage Rights and Aggregation Rights

a. **Specific Allocation of Storage Rights and Costs to CFY Customers and Suppliers (Including the RGS' proposed Rider AGG)**

b. **Aggregation Balancing Gas Charge (AGBC)**

c. **Pipeline Capacity Assignment**

d. **Customer Migration**

e. **Month-End Delivery Tolerance**

Under the Choices For You Transportation Service ("Rider CFY"), the Companies establish a Required Monthly Delivery Quantity ("RMDQ") for each customer. It is the sum of the Required Daily Delivery Quantity ("RDDQ") over the days in the month. This tells each CFY supplier how much gas it is the supposed to deliver to the utility each month. Suppliers currently have a tolerance of plus or minus 2% around RMDQ before the utility assesses a penalty. The Companies agreed to raise this tolerance to 5% in the proposed tariffs. RGS proposes to eliminate the monthly tolerance altogether. (ICC Staff Exhibit 24.0 Corrected, p. 17) Staff does not recommend that the monthly tolerance be eliminated. As explained by Staff witness

Rearden, without a separate monthly tolerance, the daily tolerance becomes the monthly tolerance. Therefore, this proposal, in effect, increases the tolerance for each RMDQ to 10%. Staff believes that it is more difficult for the utility to plan its purchases as well as storage injections and withdrawals if the monthly tolerance is too large which would result from adopting the RGS proposal. (Id., pp. 17-18)

f. Working Capital Related to System Gas Costs/Monthly Customer Aggregation Charge

2. Customer Enrollment

a. Customer Data Issues

Two customer data issues are at issue in this case, the provision of customer lists to marketers and the time of customer authorized provision of usage and billing history to marketers.

As a result of the settlement agreement in the WPS-PEC merger, the Companies agreed to provide customer lists with names and addresses to marketers. (Id., p. 27) However, while Staff signed the settlement, it did not agree that it would not oppose the agreement on customer information issues. Companies witness Zack states that the Companies will provide a customer list with service and billing addresses. (North Shore/Peoples Gas Ex. TZ-2.0, p. 55)

The marketers want the Companies to provide customers' bill payment history to them as well. RGS witness Crist argues that the Commission should direct the Companies to provide bill payment history when customers authorize it. (RGS Ex. 1.0, p. 39) The Companies doubt that customers necessarily want marketers to see their payment information. They also note that it is an administrative burden for the

Companies to monitor whether an agreement between a customer and a marketer authorizes release of customer payment history. Companies' witness Zack outlines the conditions under which the Companies agree to provide bill payment history. These conditions include Commission authorization that suppliers "warrant and represent" that they have customer permission, and that suppliers hold the Companies harmless from customers' damage claims. And that the information is provided after the supplier has begun serving the customer. The Companies offer tariff language to implement this proposal. (North Shore/People Gas Ex. TZ-2.0, pp. 56-57)

Staff believes that the Commission should not authorize release of any customer information absent explicit evidence of customer consent. (ICC Staff Exhibit 24.0 Corrected, p. 19) Sensitive personal and financial information such as payment history should not be distributed to non-utility entities, absent explicit customer approval, since the information belongs to the customer and not the marketers. The Companies gather this information from customers in their capacity as utilities and as a monopoly provider of gas delivery services. Staff understands that marketers place a high value on it, but Staff believes that the Commission should refrain from approving a program that disseminates financial information of its utility customers to marketers. In addition, Peoples Gas and North Shore Gas are placed in an uncomfortable position as an information gatekeeper, by forcing utilities to interpret contracts between the customer and its marketer. This is not a utility function. (Id., pp. 18-19) Finally, Staff believes that the Commission should be concerned that the information is not sold or used for any non-utility purpose. It is not clear what prevents marketers from reselling the information to other parties.

However, RGS points out that once customer approval is given, receiving the information only after the customer begins service defeats for purposes of receiving payment history information, since it is sensitive information. The value of the payment information is in its ability to let the marketer know whether it wants to retain the customer. Obviously, marketers want to avoid customers who are not likely to pay their bills. (RGS Ex. 2.0, pp. 23-24) Failing to provide this information will tend to raise the cost of gas to transportation customers. Vanguard points out that Nicor provides the information in a timely manner. (Vanguard Ex. 3, p. 3) Staff supports the early release of billing and usage information where specifically authorized by the customer. (ICC Staff Exhibit 24.0 Corrected, p. 19)

b. Evidence of Customer Consent

Under cross, Staff witness Rearden offered several examples about what might constitute explicit customer approval for the release of customer payment information. Several options could accomplish this task. There could be a specific contract element between the supplier and customer that explicitly authorizes, in clear, non-technical terms, the marketer to have this information. Another method that could accomplish this is through a conversation, such as with a third party vendor that verifies the agreement of the customer that it allows release of this data to marketers. Finally, electronic methods might be suitable if they are sufficiently secure and auditable. (Tr., pp. 687-693; 694) Several marketers offer Nicor's program, which uses a system that has not drawn many complaints. (Tr., pp. 703-704) Staff does not object to modeling Peoples Gas method on Nicor's, if it is explicit.

c. Minimum Stay Requirement

3. Rider SBO

a. Billing Credit

The Supplier Billing Option Service ("SBO") is a rider governing when the supplier sends one bill for both the utility and supplier charges. Nicor Advanced Energy ("NAE") witness Pishevar argues that suppliers using SBO should receive a billing credit in return for saving the Companies money and to avoid double billing transportation customers. (NAE Ex. 1.0, pp. 8-9) However, the Companies argue that it is not appropriate to grant a credit to suppliers, because there are no costs are avoided, except for printing and mailing a bill. And even those costs are not entirely avoided, since the Companies may need to periodically communicate directly with their customers. (North Shore/Peoples Gas Ex. TZ-2.0, pp. 58-59) Staff agrees with NAE that suppliers opting for SBO should receive a credit at least equal to the paper and postage costs, since the Companies avoid those costs and the costs are recovered from rates elsewhere in the tariffs. (ICC Staff Exhibit 24.0 Corrected, p. 23)

b. Order of Payments

c. NSF Checks

4. Purchase of CFY Supplier Receivables

Purchase of Receivables ("POR") is a program in which the utility, in essence, buys a marketer's charges issued to customers (the receivables). The utility then assumes the responsibility for collecting the marker's charges from the customer. To compensate it for the risk that the bills can not be collected and to cover its collection costs, the utility pays the marketers less than the full amount of the receivable. The marketers argue that the utility has better leverage to induce payment than the marketer. If the customer does not pay the bill, the utility can shut the customer off where there is a POR program. Marketers lack the ability to shut customers off. Leveraging the utility's ability to more economically recover arrearages, the utility and marketer can make a mutually beneficial trade.(ICC Staff Exhibit 24.0 Corrected, p. 23)

Staff does not recommend that the Commission order the Companies to initiate a POR program. One problem with this proposal is that it may alter the utility's regulated costs. This could happen if the discount rate in the POR does not correspond to the amount of risk assumed by the utility and revenue streams are changed. The utility business may become more risky if the POR induces marketers to target customers that are at high risk of default. Finally, Staff is concerned about the legitimacy of holding utility service hostage to payment of a bill for a competitive service. Therefore, Staff recommends that the Commission reject a POR for Peoples Gas and North Shore Gas (Id., p. 24)

5. PEGASys™ and Customer Information

E. Tariff Corrections and Clarifications

1. Rider SST, Section F

2. Rider TB, Section A

3. Rider LST-T

4. Rider SST, Section H

5. Rider SST, Section K

6. Rider TB, Section H and Rider P, Section G

7. Terms and Conditions of Service

The Companies proposed to restructure the Service Activation Charges to include activating up to four appliances for a straight turn-on and assess an additional charge for each extra appliance that needs to be activated. (North Shore Ex. VG-1.0 3REV, p. 26 and Peoples Gas Ex. VG-1.0 2REV, p. 29) The Companies provided studies with higher costs then that proposed by the Companies. Staff agrees with the Companies proposed changes and charges. (ICC Staff Exhibit 9.0, pp. 7-8)

The Companies proposed to restructure the Service Reconnection Charge in the same manner as the Service Activation Charge as well as a slight increase in the charge. (North Shore Ex. VG-1.0 3REV, p. 27 and Peoples Gas Ex. VG-1.0 2REV, p. 31) Staff agrees with the increase in the Service Reconnection Charge as well as the restructuring of charge to more specifically assign cost responsibility. (ICC Staff exhibit 9.0, p.10)

The Companies propose to charge a monthly fee for the Second Pulse Data Capability service. The Companies provided supporting documentation for this charge and Staff agrees with the proposed change. (ICC Staff Exhibit 9.0, p. 12) In Surrebuttal testimony the Companies proposed additional language revisions to the first sentence of the second paragraph to allow this tariff provision to roll over from year-to-year based on a common rollover date of May 1. (North Shores/Peoples Gas Ex. VG-3.0, p. 29) Staff recommends approval of this tariff language change to remain consistent with other Company tariffs.

Staff requested additional support and/or explanation for proposed language changes to Terms and Conditions titled "Company's Property and Protection Thereof". Staff posed several questions to the Company in relation to the proposed language for this tariff. (ICC Staff Exhibit 9.0, p. 13) Staff was not satisfied by the additional information in the Companies Rebuttal testimony (North Shore/Peoples Gas Ex. ED-2.0, p. 16) and continued to object to the proposed language of "lost margin". (ICC Staff Exhibit 21.0, p. 9) In surrebuttal testimony the Companies agreed to remove the "lost margin" language from the tariff. (North Shore/Peoples Gas Ex. ED-3.0, p. 3)

Staff requested additional support and/or explanation for proposed language changes to Terms and Conditions titled "Equipment Furnished and Maintained by Customer". (ICC Staff Exhibit 9.0, pp. 14-16) The Companies submitted additional information and modified language in rebuttal testimony. (North Shore/Peoples Gas Ex. ED-2.0, p. 14) After reviewing Mr. Doerk's rebuttal testimony, Ms. Harden testified that the language changes proposed by Mr. Doerk in his rebuttal testimony made it clear that the provisions in this section do not apply to Company-owned equipment, including the limitation of liability provision. With that revised language Staff witness Harden did not object to the proposed language, as modified by Mr. Doerk in his rebuttal testimony, in the tariff under its Terms and Conditions of Service. Therefore, Staff recommended approval of the alternate language set forth in the Companies' rebuttal testimony. (ICC Staff Exhibit 21.0, p. 9)

XI. UNION PROPOSALS

XII. CONCLUSION

Staff respectfully requests that the Illinois Commerce Commission approve Staff's recommendations in this docket.

Respectfully submitted,

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Counsel for the Staff of the
Illinois Commerce Commission

October 12, 2007

The Peoples Gas Light and Coke Company
Statement of Operating Income with Adjustments
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Company Pro Forma Present Adjusted for Rebuttal (Exhibit SF-2.5P)	Staff Adjustments (App. A p. 3)	Staff Pro Forma Present (Cols. b+c)	Company Proposed Increase (Exhibit SF-2.5P Col. F + G)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	$ 374,901	$ -	$ 374,901	$ 98,999	$ 1	$ 473,901	$ (45,427)	$ 428,474
2	PGA Revenues	1,084,326	(1,084,326)	-	-	-	-	-	-
3	Coal Tar Revenues	31,588	(31,588)	-	-	-	-	-	-
4	Other Revenues	15,688	-	15,688	-	-	15,688	-	15,688
5	Total Operating Revenue	1,506,503	(1,115,914)	390,589	98,999	1	489,589	(45,427)	444,162
6	Uncollectibles Expense	37,493	-	37,493	2,514	1	40,008	(1,154)	38,854
7	Cost of Gas	1,084,326	(1,084,326)	-	-	-	-	-	-
8	Other Production	557	-	557	-	-	557	-	557
9	Distribution	63,466	(1,620)	61,846	-	-	61,846	-	61,846
10	Customer Accounts	35,996	(1,765)	34,231	-	-	34,231	-	34,231
11	Customer Service and Informational Services	363	-	363	-	-	363	-	363
12	Sales	1,355	-	1,355	-	-	1,355	-	1,355
13	Administrative and General	131,923	(38,803)	93,120	-	-	93,120	-	93,120
14	Depreciation and Amortization	59,405	(722)	58,683	-	-	58,683	-	58,683
15	Storage	9,993	(1,648)	8,345	-	-	8,345	-	8,345
16	Transmission	2,568	-	2,568	-	-	2,568	-	2,568
17	Taxes Other than Income	18,827	(291)	18,536	-	-	18,536	-	18,536
18	Total Operating Expense								
19	Before Income Taxes	1,446,272	(1,129,175)	317,097	2,514	1	319,612	(1,154)	318,458
20	State Income Tax	4,747	1,166	5,913	7,043	-	12,956	(3,232)	9,724
21	Federal Income Tax	37,829	5,182	43,011	31,305	-	74,316	(14,364)	59,952
22	Deferred Taxes and ITCs Net	(31,363)	-	(31,363)	-	-	(31,363)	-	(31,363)
23	Total Operating Expenses	1,457,485	(1,122,827)	334,658	40,862	1	375,521	(18,750)	356,771
24	NET OPERATING INCOME	$ 49,018	$ 6,913	$ 55,931	$ 58,137	$ -	$ 114,068	$ (26,677)	$ 87,391
25	Staff Rate Base (Appendix A page 4 column (d), line 23)								$ 1,168,331
26	Staff Overall Rate of Return (ICC Staff Exhibit 17.0, Schedule 17.1)								7.48%
27	Revenue Change (column (i), line 5 minus column (d), line 5)								$ 53,573
28	Percentage Change (column (i), line 27 divided by column (d), line 5)								13.72%

The Peoples Gas Light and Coke Company
Adjustments to Operating Income
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Interest Synchronization (App. A p. 7)	Non-Base Rate Revs. & Exps. (Sch. 13.7 P)	Collection Agency Fees (Sch. 13.8 P)	PEC Officer Costs (Sch. 13.9 P)	Incentive Compensation (Sch. 14.1 P)	Capital Additions (Ex. SF 4.7P)	Rate Case Expense (Sch. 16.1 P)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	PGA Revenues	-	(1,084,326)	-	-	-	-	-	(1,084,326)
3	Coal Tar Revenues	-	(31,588)	-	-	-	-	-	(31,588)
4	Other Revenues	-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	(1,115,914)	-	-	-	-	-	(1,115,914)
6	Uncollectibles Expense	-	-	-	-	-	-	-	-
7	Cost of Gas	-	(1,084,326)	-	-	-	-	-	(1,084,326)
8	Other Production	-	-	-	-	-	-	-	-
9	Distribution	-	-	-	-	-	-	-	-
10	Customer Accounts	-	-	(1,770)	-	-	-	-	(1,770)
11	Customer Service and Informational Services	-	-	-	-	-	-	-	-
12	Sales	-	-	-	-	-	-	-	-
13	Administrative and General	-	(31,588)	-	(702)	(5,121)	-	(136)	(37,547)
14	Depreciation and Amortization	-	-	-	-	-	(202)	-	(202)
15	Storage	-	-	-	-	-	-	-	-
16	Transmission	-	-	-	-	-	-	-	-
17	Taxes Other than Income	-	-	-	-	(255)	-	-	(255)
18	Total Operating Expense								
19	Before Income Taxes	-	(1,115,914)	(1,770)	(702)	(5,376)	(202)	(136)	(1,124,100)
20	State Income Tax	198	-	129	51	392	15	10	795
21	Federal Income Tax	879	-	574	228	1,744	66	44	3,535
22	Deferred Taxes and ITCs Ne	-	-	-	-	-	-	-	-
23	Total Operating Expenses	1,077	(1,115,914)	(1,067)	(423)	(3,240)	(121)	(82)	(1,119,770)
24	NET OPERATING INCOME	$ (1,077)	$ -	$ 1,067	$ 423	$ 3,240	$ 121	$ 82	$ 3,856

The Peoples Gas Light and Coke Company
Adjustments to Operating Income
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Injuries & Damages (Sch. 16.2 P)	Non-Recurring Compressor Expense (Staff Ex. 23.0)	Hub Services (Staff Ex. 24.0)	City of Chicago Restoration Costs (GCI Sch. C-2.1)	Invested Capital Tax (App. A p. 9)	(Source)	Total Operating Statement Adjustments
	(a)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Base Rate Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	PGA Revenues	(1,084,326)	-	-	-	-	-	-	(1,084,326)
3	Coal Tar Revenues	(31,588)	-	-	-	-	-	-	(31,588)
4	Other Revenues	-	-	-	-	-	-	-	-
5	Total Operating Revenue	(1,115,914)	-	-	-	-	-	-	(1,115,914)
6	Uncollectibles Expense	-	-	-	-	-	-	-	-
7	Cost of Gas	(1,084,326)	-	-	-	-	-	-	(1,084,326)
8	Other Production	-	-	-	-	-	-	-	-
9	Distribution	-	-	-	-	(1,620)	-	-	(1,620)
10	Customer Accounts	(1,770)	-	-	5	-	-	-	(1,765)
11	Customer Service and Informational Services	-	-	-	-	-	-	-	-
12	Sales	-	-	-	-	-	-	-	-
13	Administrative and General	(37,547)	(750)	-	(506)	-	-	-	(38,803)
14	Depreciation and Amortization	(202)	-	-	(520)	-	-	-	(722)
15	Storage	-	-	(136)	(1,512)	-	-	-	(1,648)
16	Transmission	-	-	-	-	-	-	-	-
17	Taxes Other than Income	(255)	-	-	-	-	(36)	-	(291)
18	Total Operating Expense								
19	Before Income Taxes	(1,124,100)	(750)	(136)	(2,533)	(1,620)	(36)	-	(1,129,175)
20	State Income Tax	795	55	10	185	118	3	-	1,166
21	Federal Income Tax	3,535	243	44	822	526	12	-	5,182
22	Deferred Taxes and ITCs Ne	-	-	-	-	-	-	-	-
23	Total Operating Expenses	(1,119,770)	(452)	(82)	(1,526)	(976)	(21)	-	(1,122,827)
24	NET OPERATING INCOME	$ 3,856	$ 452	$ 82	$ 1,526	$ 976	$ 21	$ -	$ 6,913

The Peoples Gas Light and Coke Company
Rate Base
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Company Rebuttal Adjusted Rate Base (Exhibit SF-2.1P)	Staff Adjustments (App. A p. 6)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Utility Plant	$ 2,439,299	$ (49,229)	$ 2,390,070
2	Accumulated Provision for Depreciation and Amortizatic	(934,421)	4,486	(929,935)
3		-	-	-
4	Net Plant	$ 1,504,878	$ (44,743)	$ 1,460,135
5	Additions to Rate Base:			
6	Materials and Supplies	8,796	-	8,796
7	Cash Working Capital	30,896	(14,315)	16,581
8	Gas in Storage	86,667	(40,277)	46,390
9	Budget Plan Balances	14,080	-	14,080
10	Unamortized Rate Case Expense	2,908	(2,908)	-
11		-	-	-
12	Deductions From Rate Base:			
13	Accumulated Deferred Income Taxes	(310,757)	25,803	(284,954)
14	Pre-1971 Investment Tax Credits	(54)	-	(54)
15	Reserve for Injuries and Damages	(4,422)	-	(4,422)
16	Customer Advances for Construction	(392)	-	(392)
17	Customer Deposits	(32,176)	-	(32,176)
18	Accrued Postretirement Benefits Other than Pensions ("OPEB")	-	(55,653)	(55,653)
19		-	-	-
20		-	-	-
21		-	-	-
22		-	-	-
23	Rate Base	$ 1,300,424	$ (132,093)	$ 1,168,331

The Peoples Gas Light and Coke Company

Adjustments to Rate Base

For the Test Year Ending September 30, 2006

(In Thousands)

Line No.	Description	Incentive Compensation (Sch. 14.1 P)	Cash Working Capital (Sch. 15.1 P)	Capital Additions (Ex. SF 4.7 P)	Gas in Storage Accts Payable (Sch. 15.3 P)	Rate Case Expense (Sch. 16.1 P)	Working Capital Allowance (Sch. 23.1 P)	Hub Services (Staff Ex. 24.0)	Subtotal Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Utility Plant	$ (303)	$ -	$ (8,827)	$ -	$ -	$ -	$ (39,019)	$ (48,149)
2	Accumulated Provision for Depreciation and Amortization	122	-	202	-	-	-	4,162	4,486
3		-	-	-	-	-	-	-	-
4	Net Plant	$ (181)	$ -	$ (8,625)	$ -	$ -	$ -	$ (34,857)	$ (43,663)
5	Additions to Rate Base:								
6	Materials and Supplies	-	-	-	-	-	-	-	-
7	Cash Working Capital	-	(14,315)	-	-	-	-	-	(14,315)
8	Gas in Storage	-	-	-	(26,727)	-	(13,550)	-	(40,277)
9	Budget Plan Balances	-	-	-	-	-	-	-	-
10	Unamortized Rate Case Expense	-	-	-	-	(2,908)	-	-	(2,908)
11		-	-	-	-	-	-	-	-
12	Deductions From Rate Base:	-	-	-	-	-	-	-	-
13	Accumulated Deferred Income Taxes	-	-	564	-	1,156	-	-	1,720
14	Pre-1971 Investment Tax Credits	-	-	-	-	-	-	-	-
15	Reserve for Injuries and Damages	-	-	-	-	-	-	-	-
16	Customer Advances for Construction	-	-	-	-	-	-	-	-
17	Customer Deposits	-	-	-	-	-	-	-	-
18	Accrued Postretirement Benefits Other than Pensions ("OPEB")	-	-	-	-	-	-	-	-
19		-	-	-	-	-	-	-	-
20		-	-	-	-	-	-	-	-
21		-	-	-	-	-	-	-	-
22		-	-	-	-	-	-	-	-
23	Rate Base	$ (181)	$ (14,315)	$ (8,061)	$ (26,727)	$ (1,752)	$ (13,550)	$ (34,857)	$ (99,443)

The Peoples Gas Light and Coke Company

Adjustments to Rate Base

For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Subtotal Rate Base Adjustments	OPEB Liability (Sch. 14.2 P)	City of Chicago Restoration Costs (GCI Sch. C-2.1)	(Source)	(Source)	(Source)	(Source)	Total Rate Base Adjustments
	(a)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Gross Utility Plant	$ (48,149)	$ -	$ (1,080)	$ -	$ -	$ -	$ -	$ (49,229)
2	Accumulated Provision for Depreciation and Amortization	4,486	-	-	-	-	-	-	4,486
3	-	-	-	-	-	-	-	-	-
4	Net Plant	(43,663)	-	(1,080)	-	-	-	-	(44,743)
	-								
5	Additions to Rate Base:								-
6	Materials and Supplies	-	-	-	-	-	-	-	-
7	Cash Working Capital	(14,315)	-	-	-	-	-	-	(14,315)
8	Gas in Storage	(40,277)	-	-	-	-	-	-	(40,277)
9	Budget Plan Balances	-	-	-	-	-	-	-	-
10	Unamortized Rate Case Expense	(2,908)	-	-	-	-	-	-	(2,908)
11	-	-	-	-	-	-	-	-	-
12	Deductions From Rate Base:	-	-	-	-	-	-	-	-
13	Accumulated Deferred Income Taxes	1,720	24,083	-	-	-	-	-	25,803
14	Pre-1971 Investment Tax Credits	-	-	-	-	-	-	-	-
15	Reserve for Injuries and Damages	-	-	-	-	-	-	-	-
16	Customer Advances for Construction	-	-	-	-	-	-	-	-
17	Customer Deposits	-	-	-	-	-	-	-	-
18	Accrued Postretirement Benefits Other than Pensions ("OPEB")	-	(55,653)	-	-	-	-	-	(55,653)
19	-	-	-	-	-	-	-	-	-
20	-	-	-	-	-	-	-	-	-
21	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
23	Rate Base	$ (99,443)	$ (31,570)	$ (1,080)	$ -	$ -	$ -	$ -	$ (132,093)

The Peoples Gas Light and Coke Company
Interest Synchronization Adjustment
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Amount	
	(a)	(b)	
1	Rate Base	$ 1,168,331	(1)
2	Weighted Cost of Debt	2.05%	(2)
3	Synchronized Interest Per Staff (Line 1 x Line 2)	$ 23,951	
4	Company Interest Expense	26,659	(3)
5	Increase (Decrease) in Interest Expense	$ (2,708)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.300%	$ 198	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 879	

(1) Source: Appendix A, page 4, column (d), line 23
(2) Source: ICC Staff Exhibit 17.0, Schedule 17.1
(3) Source: Company Exhibit SF-2.14 P, line 3

The Peoples Gas Light and Coke Company

Gross Revenue Conversion Factor

For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	1.000000
2	Uncollectibles	2.5400%	0.025400	
3	State Taxable Income		0.974600	
4	State Income Tax	7.3000%	0.071146	0.073000
5	Federal Taxable Income		0.903454	0.927000
6	Federal Income Tax	35.0000%	0.316209	0.324450
7	Operating Income		0.587245	0.602550
8	Gross Revenue Conversion Factor Per Staff (Line 1 / Line 7)		1.702867	1.659613

The Peoples Gas Light and Coke Company
Adjustment to Invested Capital Taxes
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	Net Operating Income Increase Per Staff Prior to ICT	$ 53,608	Appendix A Sch.1 prior to tax
2	Invested Capital Taxes Rate	0.8%	Staff Cross Fiorella Exhibit 1
3	Invested Capital Taxes per Staff Initial Brief	$ 429	Line 1 x line 2
4	Invested Capital Taxes per Staff Rebuttal Testimony	$ 465	See Notes 1 and 2
5	Adjustment to ICT	$ (36)	Line 3 - line 4

Note 1
See Exhibit SF-4.5 P. Staff Corrected Company Direct of $478,000 minus Company rebuttal adjustment of $13,000 from Exhibit SF-2.13P.

Note 2
This amount represents the Company's rebuttal ICT pro forma adjustment. It was inadvertantly not adjusted in Staff's contested rebuttal revenue requirement adjustments.

The Peoples Gas Light and Coke Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Thousands)

Line (A)	Item (B)	Amount (C)	Lag (Lead) (D)	CWC Factor (E) (D/365)	CWC Requirement (F) (C*E)	Column C Source (G)
1	Revenues	$ 1,382,012	49.44	0.13545	$ 187,196	Appendix A page 1
2	Pensions and Benefits	36,991	(28.50)	(0.07808)	(2,888)	Appendix A page 12
3	Payroll and Withholdings	94,128	(14.23)	(0.03899)	(3,670)	Appendix A page 12
4	Inter Company Billings	66,656	(36.22)	(0.09923)	(6,614)	Company Schedule C-13, Page 1 of 4, Column C, Line 14
5	Natural Gas	1,084,326	(42.05)	(0.11521)	(124,920)	ICC Staff Ex. 13.0, Sch. 13.7 P, Column B, Line 2
6	Other Operations and Maintenance	123,714	(49.51)	(0.13564)	(16,781)	Appendix A page 1
7	Taxes Other Than Income and Real Estate	17,019	(40.30)	(0.11041)	(1,879)	Appendix A page 11
8	Real Estate Taxes	1,517	(380.09)	(1.04134)	(1,580)	Appendix A page 11
9	Interest Expense	23,951	(76.99)	(0.21093)	(5,052)	Appendix A page 7
10	Federal Income Tax	59,952	(37.88)	(0.10378)	(6,222)	Appendix A page 1
11	State Income Tax	9,724	(37.88)	(0.10378)	(1,009)	Appendix A page 1
12	TOTAL				$ 16,581	Sum of Lines 1 through 11
13	Cash Working Capital per Staff		$ 16,581			Line 12
14	Cash Working Capital per Company		30,896			Company Exhibit SF-2.1P, Line 4
15	Difference -- Staff Adjustment		$ (14,315)			Line 13 minus Line 14

Note: Lag (Lead) is from Company Schedule B-1; except for Lines 7 & 8 which are from ICC Staff Ex. 15.0, Sch. 15.1 P, Page 4 of 4, Column J, Line 19 and Column E, Line 13, respectfully

The Peoples Gas Light and Coke Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Thousands)

Line (A)	Revenues (B)		Amount (C)	Source (D)
1	Total Operating Revenues	$	444,162	Appendix A page 1, Line 5
2	PGA Revenue		1,084,326	ICC Staff Ex. 13.0, Sch. 13.7 P, Column B, Line 2
3	Uncollectible Accounts		(38,854)	Appendix A page 1 Line 6
4	Depreciation & Amortization		(58,683)	Appendix A page 1 Line 14
5	Return on Equity		(48,939)	Line 9 below
6	Total Revenues for CWC calculation	$	1,382,012	Sum of Lines 1 through 5
7	Total Return on Rate Base	$	87,391	Appendix A page 1 Line 24
8	Percentage Equity		56.00%	ICC Staff Ex. 17.0, Schedule 17.1
9	Return on Equity	$	48,939	Line 7 times Line 8
10	O & M Expenses	$	318,458	Appendix A page 1 Line 19
11	Pensions and Benefits		(31,011)	Company Schedule B-8, Page 1 of 2, Column H, Line 1
12	Payroll and Withholdings		(58,223)	Company Schedule B-8, Page 1 of 2, Column H, Line 2
13	Uncollectible Accounts		(38,854)	Appendix A page 1 Line 6
14	Inter Company Billings		(66,656)	Company Schedule C-13, Page 1 of 4, Column C, Line 14
15	Other Operations & Maintenance	$	123,714	Sum of Lines 10 through 13
16	Taxes Other Than Income		18,536	Appendix A page 1 Line 17
17	Less Real Estate Tax		(1,517)	Company Schedule C-18, Page 4 of 4, Column F, Line 18
18	Taxes Other Than Income and Real Estate	$	17,019	Sum of Lines 16 and 17

The Peoples Gas Light and Coke Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Thousands)

Line (A)	Description (B)	Amount (C)	Source (D)
1	Pensions and Benefits per Company Filing	$ 34,835	Company Schedule C-11.3, Page 4 of 4, Column C, Line 7
2	Medical & Insurance Cost Adjustment	2,592	Company Schedule C-2.10, Line 11
3	Capitalized Portion of Line 2	475	Line 2 Divided by Percentage Expensed (84.52% from Company Schedule C-11.3, Page 4 of 4, Column G, Line 7) Less Line 2
4	Pension Cost Decrease	(770)	Company Schedule C-2.15, Line 11
5	Capitalized Portion of Line 4	(141)	Line 4 Divided by Percentage Expensed (84.52% from Company Schedule C-11.3, Page 4 of 4, Column G, Line 7) Less Line 4
6	Pensions and Benefits per Staff	$ 36,991	Sum of Lines 1 through 5
7	Direct Payroll per Company Filing	$ 96,587	Company Schedule C-11.1, Column B, Line 12
8	Annualize O&M Union Wage & Nonunion Merit Increases 2006	605	Company Schedule C-2.13, Line 11
9	Capitalized Portion of Line 8	138	Line 8 Divided by Percentage Expensed (81.42% from Company WPC-2.13.2) Less Line 8
10	Annualize O&M Union Wage & Nonunion Merit Increases 2007	1,550	Company Schedule C-2.14, Line 11
11	Capitalized Portion of Line 10	369	Line 10 Divided by Percentage Expensed (80.79% from Company WPC-2.14.2) Less Line 10
12	Staff Adjustment for Incentive Compensation	(5,121)	ICC Staff Ex. 14.0, Sch.14.1 P
13	Direct Payroll per Staff	$ 94,128	Sum of Lines 7 through 12

The Peoples Gas Light and Coke Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Dollars)

		Weighted Expense Lead Times per Company's WPB-8, Page 95 of 99				Weighted Expense Lead Times Restated by Staff without Real Estate Taxes				
Line	Tax	Amount	Percent of Total Amount	Lead	Weighted Lead	Amount	Percent of Total Amount	Lead	Weighted Lead	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			(C/sum(C))		(D * E)		(G/sum(G))		(H * I)	Company WPB-8, Taxes, Page 95 of 99:
1	FICA	14,046,840	6.27%	15.88	1.00	14,046,840	6.33%	15.88	1.01	Line 1
2	FUTA	91,640	0.04%	76.38	0.03	91,640	0.04%	76.38	0.03	Line 2
3	SUTA	1,095,706	0.49%	73.38	0.36	1,095,706	0.49%	73.38	0.36	Line 3
4	ICC Gas Rev. (PUF)	1,660,000	0.74%	(32.52)	(0.24)	1,660,000	0.75%	(32.52)	(0.24)	Line 4
5	Invested Capital	8,596,416	3.84%	30.06	1.15	8,596,416	3.88%	30.06	1.17	Line 5
6	Federal Excise	15,701	0.01%	73.27	0.01	15,701	0.01%	73.27	0.01	Line 6
7	GRS Receipts/MUT	121,735,397	54.34%	52.88	28.74	121,735,397	54.89%	52.88	29.02	Line 7
8	Energy Assistance	9,342,547	4.17%	42.65	1.78	9,342,547	4.21%	42.65	1.80	Line 8
9	Corp. Franchise	165,306	0.07%	184.86	0.14	165,306	0.07%	184.86	0.14	Line 9
10	Gas Rev./ Pub. Util.	38,732,399	17.29%	5.45	0.94	38,732,399	17.46%	5.45	0.95	Line 10
11	Illinois Gas Use	270,100	0.12%	42.64	0.05	270,100	0.12%	42.64	0.05	Line 11
12	Illinois Motor Fuel	50,244	0.02%	42.65	0.01	50,244	0.02%	42.65	0.01	Line 12
13	Property/R. E.	2,215,342	0.99%	**380.09**	3.76					Line 13
14	Chicago Payroll	70,244	0.03%	79.29	0.02	70,244	0.03%	79.29	0.03	Line 14
15	Chicago Use	188,191	0.08%	235.86	0.20	188,191	0.08%	235.86	0.20	Line 15
16	Chicago Gas Use	25,720,198	11.48%	49.78	5.72	25,720,198	11.60%	49.78	5.77	Line 16
17	Chicago Gas Lease	1,507	0.00%	49.78	0.00	1,507	0.00%	49.78	0.00	Line 17
18	Chicago Cars/MV	11,292	0.01%	52.82	0.00	11,292	0.01%	52.82	0.00	Line 18
19	**Totals**	224,009,070	100.00%		43.66	221,793,728	100.00%		**40.30**	

North Shore Gas Company
Statement of Operating Income with Adjustments
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Company Pro Forma Present Adjusted for Rebuttal (Exhibit SF-2.5N)	Staff Adjustments (App. B p. 3)	Staff Pro Forma Present (Cols. b+c)	Company Proposed Increase (Exhibit SF-2.5N Col. F + G)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	$ 62,013	$ -	$ 62,013	$ 4,245	$ -	$ 66,258	$ (5,683)	$ 60,575
2	PGA Revenues	226,316	(226,316)	-	-	-	-	-	-
3	Coal Tar Revenues	2,065	(2,065)	-	-	-	-	-	-
4	Other Revenues	1,639	-	1,639	-	-	1,639	-	1,639
5	Total Operating Revenue	292,033	(228,381)	63,652	4,245	-	67,897	(5,683)	62,214
6	Uncollectibles Expense	1,982	-	1,982	30	-	2,012	(40)	1,972
7	Cost of Gas	226,316	(226,316)	-	-	-	-	-	-
8	Other Production	170	-	170	-	-	170	-	170
9	Distribution	7,615	-	7,615	-	-	7,615	-	7,615
10	Customer Accounts	6,308	(76)	6,232	-	-	6,232	-	6,232
11	Customer Service and Informational Services	40	-	40	-	-	40	-	40
12	Sales	35	-	35	-	-	35	-	35
13	Administrative and General	21,249	(2,959)	18,290	-	-	18,290	-	18,290
14	Depreciation	6,166	(72)	6,094	-	-	6,094	-	6,094
15	Storage	-	-	-	-	-	-	-	-
16	Transmission	95	-	95	-	-	95	-	95
17	Taxes Other than Income	2,074	(55)	2,019	-	-	2,019	-	2,019
18	Total Operating Expense								
19	Before Income Taxes	272,050	(229,478)	42,572	30	-	42,602	(40)	42,562
20	State Income Tax	3	106	109	308	-	417	(412)	5
21	Federal Income Tax	2,195	473	2,668	1,367	1	4,036	(1,831)	2,205
22	Deferred Taxes and ITCs Net	3,497	-	3,497	-	-	3,497	-	3,497
23	Total Operating Expenses	277,745	(228,899)	48,846	1,705	1	50,552	(2,283)	48,269
24	NET OPERATING INCOME	$ 14,288	$ 518	$ 14,806	$ 2,540	$ (1)	$ 17,345	$ (3,400)	$ 13,945
25	Staff Rate Base (Appendix B page 4, column (d), line 23)								$ 181,332
26	Staff Overall Rate of Return (ICC Staff Exhibit 17.0, Schedule 17.1)								7.69%
27	Revenue Change (column (i), line 5 minus column (d), line 5)								$ (1,438)
28	Percentage Change (column (i), line 27 divided by column (d), line 5)								-2.26%

North Shore Gas Company
Adjustments to Operating Income
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Interest Synchronization (App. B p. 6)	Non-Base Rate Revs. & Exps. (Sch. 13.7 N)	Collection Agency Fees (Sch. 13.8 N)	PEC Officer Costs (Sch. 13.9 N)	Incentive Compensation (Sch. 14.1 N)	Capital Additions (Sch. 15.2 N)	Rate Case Expense (Sch. 16.1 N)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	PGA Revenues	-	(226,316)	-	-	-	-	-	(226,316)
3	Coal Tar Revenues	-	(2,065)	-	-	-	-	-	(2,065)
4	Other Revenues	-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	(228,381)	-	-	-	-	-	(228,381)
6	Uncollectibles Expense	-	-	-	-	-	-	-	-
7	Cost of Gas	-	(226,316)	-	-	-	-	-	(226,316)
8	Other Production	-	-	-	-	-	-	-	-
9	Distribution	-	-	-	-	-	-	-	-
10	Customer Accounts	-	-	(76)	-	-	-	-	(76)
11	Customer Service and Informational Services	-	-	-	-	-	-	-	-
12	Sales	-	-	-	-	-	-	-	-
13	Administrative and General	-	(2,065)	-	(100)	(552)	-	(138)	(2,855)
14	Depreciation	-	-	-	-	-	(72)	-	(72)
15	Storage	-	-	-	-	-	-	-	-
16	Transmission	-	-	-	-	-	-	-	-
17	Taxes Other than Income	-	-	-	-	(24)	-	-	(24)
18	Total Operating Expense								
19	Before Income Taxes	-	(228,381)	(76)	(100)	(576)	(72)	(138)	(229,343)
20	State Income Tax	26	-	6	7	42	5	10	96
21	Federal Income Tax	117	-	25	32	187	23	45	429
22	Deferred Taxes and ITCs Ne	-	-	-	-	-	-	-	-
23	Total Operating Expenses	143	(228,381)	(45)	(61)	(347)	(44)	(83)	(228,818)
24	NET OPERATING INCOME	$ (143)	$ -	$ 45	$ 61	$ 347	$ 44	$ 83	$ 437

North Shore Gas Company
Adjustments to Operating Income
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Injuries & Damages (Sch. 16.2 N)	Invested Capital Tax (App. B p. 9)	(Source)	(Source)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Base Rate Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	PGA Revenues	(226,316)	-	-	-	-	-	-	(226,316)
3	Coal Tar Revenues	(2,065)	-	-	-	-	-	-	(2,065)
4	Other Revenues	-	-	-	-	-	-	-	-
5	Total Operating Revenue	(228,381)	-	-	-	-	-	-	(228,381)
6	Uncollectibles Expense	-	-	-	-	-	-	-	-
7	Cost of Gas	(226,316)	-	-	-	-	-	-	(226,316)
8	Other Production	-	-	-	-	-	-	-	-
9	Distribution	-	-	-	-	-	-	-	-
10	Customer Accounts	(76)	-	-	-	-	-	-	(76)
11	Customer Service and Informational Services	-	-	-	-	-	-	-	-
12	Sales	-	-	-	-	-	-	-	-
13	Administrative and General	(2,855)	(104)	-	-	-	-	-	(2,959)
14	Depreciation	(72)	-	-	-	-	-	-	(72)
15	Storage	-	-	-	-	-	-	-	-
16	Transmission	-	-	-	-	-	-	-	-
17	Taxes Other than Income	(24)	-	(31)	-	-	-	-	(55)
18	Total Operating Expense								
19	Before Income Taxes	(229,343)	(104)	(31)	-	-	-	-	(229,478)
20	State Income Tax	96	8	2	-	-	-	-	106
21	Federal Income Tax	429	34	10	-	-	-	-	473
22	Deferred Taxes and ITCs Ne	-	-	-	-	-	-	-	-
23	Total Operating Expenses	(228,818)	(62)	(19)	-	-	-	-	(228,899)
24	NET OPERATING INCOME	$ 437	$ 62	$ 19	$ -	$ -	$ -	$ -	$ 518

North Shore Gas Company
Rate Base
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Company Rebuttal Adjusted Rate Base (Exhibit SF-2.1N)	Staff Adjustments (App. B p. 5)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Utility Plant	$ 380,084	$ (1,780)	$ 378,304
2	Accumulated Provision for Depreciation and Amortization	(148,643)	90	(148,553)
3		-	-	-
4	Net Plant	$ 231,441	$ (1,690)	$ 229,751
5	Additions to Rate Base:			
6	Materials and Supplies	1,539	-	1,539
7	Gas in Storage	10,507	(7,521)	2,986
8	Budget Plan Balances	849	-	849
9	Unamortized Rate Case Expense	2,290	(2,290)	-
10		-	-	-
11		-	-	-
12	Deductions From Rate Base:			
13	Accumulated Deferred Income Taxes	(45,325)	3,980	(41,345)
14	Customer Advances for Construction	(748)	-	(748)
15	Customer Deposits	(2,860)	-	(2,860)
16	Cash Working Capital	(1,124)	(622)	(1,746)
17	Accrued Postretirement Benefits Other than Pensions ("OPEB")	-	(7,094)	(7,094)
18		-	-	-
19		-	-	-
20		-	-	-
21		-	-	-
22		-	-	-
23	Rate Base	$ 196,569	$ (15,237)	$ 181,332

North Shore Gas Company
Adjustments to Rate Base
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Incentive Compensation (Sch. 14.1 N)	Cash Working Capital (Sch. 15.1 N)	Capital Additions (Sch. 15.2 N)	Gas in Storage Accts Payable (Sch. 15.3 N)	Rate Case Expense (Sch. 16.1 N)	Working Capital Allowance (Sch. 23.1 N)	OPEB Liability (Sch. 14.2 N)	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Utility Plant	$ (46)	$ -	$ (1,734)	$ -	$ -	$ -	$ -	$ (1,780)
2	Accumulated Provision for Depreciation and Amortization	18	-	72	-	-	-	-	90
3		-	-	-	-	-	-	-	-
4	Net Plant	$ (28)	$ -	$ (1,662)	$ -	$ -	$ -	$ -	$ (1,690)
5	Additions to Rate Base:								
6	Materials and Supplies	-	-	-	-	-	-	-	-
7	Gas in Storage	-	-	-	(6,098)	-	(1,423)	-	(7,521)
8	Budget Plan Balances	-	-	-	-	-	-	-	-
9	Unamortized Rate Case Expense	-	-	-	-	(2,290)	-	-	(2,290)
10		-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-
12	Deductions From Rate Base:	-	-	-	-	-	-	-	-
13	Accumulated Deferred Income Taxes	-	-	50	-	910	-	3,020	3,980
14	Customer Advances for Construction	-	-	-	-	-	-	-	-
15	Customer Deposits	-	-	-	-	-	-	-	-
16	Cash Working Capital	-	(622)	-	-	-	-	-	(622)
17	Accrued Postretirement Benefits Other than Pensions ("OPEB")	-	-	-	-	-	-	(7,094)	(7,094)
18		-	-	-	-	-	-	-	-
19		-	-	-	-	-	-	-	-
20		-	-	-	-	-	-	-	-
21		-	-	-	-	-	-	-	-
22		-	-	-	-	-	-	-	-
23	Rate Base	$ (28)	$ (622)	$ (1,612)	$ (6,098)	$ (1,380)	$ (1,423)	$ (4,074)	$ (15,237)

North Shore Gas Company
Interest Synchronization Adjustment
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Amount
	(a)	(b)
1	Rate Base	$ 181,332 [1]
2	Weighted Cost of Debt	2.37% [2]
3	Synchronized Interest Per Staff (Line 1 x Line 2)	$ 4,298
4	Company Interest Expense	4,659 [3]
5	Increase (Decrease) in Interest Expense	$ (361)
6	Increase (Decrease) in State Income Tax Expense	
7	at 7.300%	$ 26
8	Increase (Decrease) in Federal Income Tax Expense	
9	at 35.000%	$ 117

(1) Source: Appendix B, page 4, column (d), line 23
(2) Source: ICC Staff Exhibit 17.0, Schedule 17.1
(3) Source: Company Exhibit SF-2.14 N, line 3

North Shore Gas Company
Gross Revenue Conversion Factor
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	1.000000
2	Uncollectibles	0.7000%	0.007000	
3	State Taxable Income		0.993000	
4	State Income Tax	7.3000%	0.072489	0.073000
5	Federal Taxable Income		0.920511	0.927000
6	Federal Income Tax	35.0000%	0.322179	0.324450
7	Operating Income		0.598332	0.602550
8	Gross Revenue Conversion Factor Per Staff (Line 1 / Line 7)		1.671313	1.659613

North Shore Gas Company
Adjustment to Invested Capital Taxes
For the Test Year Ending September 30, 2006
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	Net Operating Income Decrease Per Staff Prior to ICT	$ (1,407)	Appendix B Sch.1 prior to tax
2	Invested Capital Taxes Rate	0.8%	Staff Cross Fiorella Exhibit 1
3	Invested Capital Taxes per Staff Initial Brief	$ (11)	Line 1 x line 2
4	Invested Capital Taxes per Staff Rebuttal Testimony	$ 20	See Notes 1 and 2
5	Adjustment to ICT	$ (31)	Line 3 - line 4

Note 1
See Exhibit SF-4.5 N. Staff Corrected Company Direct of $30,000 minus Company rebuttal adjustment of $10,000 from Exhibit SF-2.13P.

Note 2
This amount represents the Company's rebuttal ICT pro forma adjustment. It was inadvertantly not adjusted in Staff's contested rebuttal revenue requirement adjustments.

North Shore Gas Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Thousands)

Line (A)	Item (B)	Amount (C)	Lag (Lead) (D)	CWC Factor (E) (D/365)	CWC Requirement (F) (C*E)	Column C Source (G)
1	Revenues	$ 272,655	41.08	0.11255	$ 30,687	Appendix B page 1
2	Pensions and Benefits	6,439	(40.92)	(0.11211)	(722)	Appendix B page 11
3	Payroll and Withholdings	11,381	(14.83)	(0.04063)	(462)	Appendix B page 11
4	Inter Company Billings	17,234	(36.78)	(0.10077)	(1,737)	Company Schedule C-13, Page 1 of 2, Column C, Line 14
5	Natural Gas	226,316	(41.84)	(0.11463)	(25,943)	ICC Staff Ex. 13.0, Sch. 13.7 N, Column B, Line 2
6	Other Operations and Maintenance	13,371	(55.35)	(0.15164)	(2,028)	Appendix B page 1
7	Taxes Other Than Income and Real Estate	1,981	(36.39)	(0.09969)	(197)	Appendix B page 10
8	Real Estate Taxes	38	(377.39)	(1.03395)	(39)	Appendix B page 10
9	Interest Expense	4,298	(91.25)	(0.25000)	(1,075)	Appendix B page 7
10	Federal Income Tax	2,205	(37.88)	(0.10378)	(229)	Appendix B page 1
11	State Income Tax	5	(37.88)	(0.10378)	(1)	Appendix B page 1
12	TOTAL				$ (1,746)	Sum of Lines 1 through 11
13	Cash Working Capital per Staff		$ (1,746)			Line 12
14	Cash Working Capital per Company		(1,124)			Company Exhibit SF-2.1N, Line 4
15	Difference -- Staff Adjustment		$ (622)			Line 13 minus Line 14

Note: Lag (Lead) is from Company Schedule B-1; except for Lines 7 & 8 which are from ICC Staff Ex. 15.0, Sch. 15.1 N, Page 4 of 4, Column J, Line 19 and Column E, Line 13, respectfully

North Shore Gas Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Thousands)

Line (A)	Revenues (B)	Amount (C)	Source (D)
1	Total Operating Revenues	$ 62,214	Appendix B page 1, Line 5
2	PGA Revenue	226,316	ICC Staff Ex. 13.0, Sch. 13.7 N, Column B, Line 2
3	Uncollectible Accounts	(1,972)	Appendix B page 1 Line 6
4	Depreciation & Amortization	(6,094)	Appendix B page 1 Line 14
5	Return on Equity	(7,809)	Line 9 below
6	Total Revenues for CWC calculation	$ 272,655	Sum of Lines 1 through 5
7	Total Return on Rate Base	$ 13,944	Appendix B page 1 Line 24
8	Percentage Equity	56.00%	ICC Staff Ex. 17.0, Schedule 17.1
9	Return on Equity	$ 7,809	Line 7 times Line 8
10	O & M Expenses	$ 42,562	Appendix B page 1 Line 19
11	Pensions and Benefits	(4,765)	Company Schedule B-8, Page 1 of 2, Column H, Line 1
12	Payroll and Withholdings	(5,220)	Company Schedule B-8, Page 1 of 2, Column H, Line 2
13	Uncollectible Accounts	(1,972)	Appendix B page 1 Line 6
14	Inter Company Billings	(17,234)	Company Schedule C-13, Page 1 of 2, Column C, Line 14
15	Other Operations & Maintenance	$ 13,371	Sum of Lines 10 through 13
16	Taxes Other Than Income	2,019	Appendix B page 1 Line 17
17	Less Real Estate Tax	(38)	Company Schedule C-18, Page 4 of 4, Column F, Line 18
18	Taxes Other Than Income and Real Estate	$ 1,981	Sum of Lines 16 and 17

North Shore Gas Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Thousands)

Line (A)	Description (B)	Amount (C)	Source (D)
1	Pensions and Benefits per Company Filing	$ 6,634	Company Schedule C-11.3, Page 4 of 4, Column C, Line 7
2	Medical & Insurance Cost Adjustment	144	Company Schedule C-2.10, Line 11
3	Capitalized Portion of Line 2	42	Line 2 Divided by Percentage Expensed (77.54% from Company Schedule C-11.3, Page 4 of 4, Column G, Line 7) Less Line 2
4	Pension Cost Decrease	(295)	Company Schedule C-2.15, Line 11
5	Capitalized Portion of Line 4	(85)	Line 4 Divided by Percentage Expensed (77.54% from Company Schedule C-11.3, Page 4 of 4, Column G, Line 7) Less Line 4
6	Pensions and Benefits per Staff	$ 6,439	Sum of Lines 1 through 5
7	Direct Payroll per Company Filing	$ 11,579	Company Schedule C-11.1, Column B, Line 12
8	Annualize O&M Union Wage & Nonunion Merit Increases 2006	93	Company Schedule C-2.13, Line 11
9	Capitalized Portion of Line 8	30	Line 8 Divided by Percentage Expensed (75.82% from Company WPC-2.13.2) Less Line 8
10	Annualize O&M Union Wage & Nonunion Merit Increases 2007	167	Company Schedule C-2.14, Line 11
11	Capitalized Portion of Line 10	65	Line 10 Divided by Percentage Expensed (72.06% from Company WPC-2.14.2) Less Line 10
12	Staff Adjustment for Incentive Compensation	(552)	ICC Staff Ex. 14.0, Sch. 14.2 N, Page 2
13	Direct Payroll per Staff	$ 11,381	Sum of Lines 7 through 12

North Shore Gas Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Dollars)

		Weighted Expense Lead Times per Company's WPB-8, Page 32 of 36				Weighted Expense Lead Times Restated by Staff without Real Estate Taxes				
Line	Tax	Amount	Percent of Total Amount	Lead	Weighted Lead	Amount	Percent of Total Amount	Lead	Weighted Lead	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			(C/sum(C))		(D * E)		(G/sum(G))		(H * I)	Company WPB-8, Taxes, Page 32 of 36:
1	FICA	$ 1,721,804	8.19%	16.70	1.37	$ 1,721,804	8.28%	16.70	1.38	Line 1
2	FUTA	11,996	0.06%	76.38	0.04	11,996	0.06%	76.38	0.04	Line 2
3	SUTA	61,774	0.29%	76.38	0.22	61,774	0.30%	76.38	0.23	Line 3
4	ICC Gas Rev. (PUF)	320,000	1.52%	(32.99)	(0.50)	320,000	1.54%	(32.99)	(0.51)	Line 4
5	Invested Capital	1,259,560	5.99%	30.03	1.80	1,259,560	6.06%	30.03	1.82	Line 5
6	Federal Excise	42	0.00%	73.27	0.00	42	0.00%	73.27	0.00	Line 6
7	GRS Receipts/MUT	7,476,564	35.56%	76.35	27.15	7,476,564	35.97%	76.35	27.46	Line 7
8	Energy Assistance	1,565,589	7.45%	42.18	3.14	1,565,589	7.53%	42.18	3.18	Line 8
9	Corp. Franchise	24,757	0.12%	179.39	0.21	24,757	0.12%	179.39	0.21	Line 9
10	Gas Rev./ Pub. Util.	8,337,399	39.65%	6.37	2.53	8,337,399	40.11%	6.37	2.56	Line 10
11	Illinois Gas Use	6,543	0.03%	42.55	0.01	6,543	0.03%	42.55	0.01	Line 11
12	Illinois Motor Fuel	110	0.00%	42.09	0.00	110	0.00%	42.09	0.00	Line 12
13	Property/R. E.	240,105	1.14%	**377.39**	4.31					Line 13
14	**Totals**	$ 21,026,243	100.00%		40.28	$ 20,786,138	100.00%		**36.39**	

The Peoples Gas Light and Coke Company
Comparison of Staff Cost of Service with Company Cost of Service Study
at Company-proposed Revenue Requirement

Line No.		SC 1N	SC 1H	SC 2	SC 3 and 4	SC 8	SC 6
1	Staff	$ 29,061,995	$ 297,526,159	$ 127,656,841	$ 15,858,630	$ 17,957	$ 59,119
2	Company, with Rider UBA	$ 27,845,018	$ 278,505,514	$ 123,175,002	$ 13,850,031	$ 16,658	$ 59,478
3	Plus: Uncollectible Gas Costs	$ 1,432,688	$ 21,033,253	$ 4,175,110	$ 88,207		
4	Total Company	$ 29,277,706	$ 299,538,767	$ 127,350,112	$ 13,938,238	$ 16,658	$ 59,478
5	Difference	$ (215,711)	$ (2,012,608)	$ 306,729	$ 1,920,392	$ 1,299	$ (359)

Sources:

Line No. 1: ICC Staff Exhibit 19.0, Schedule 19.2-PG, Total Revenue Requirement ***Sub-total***
Line No. 2: North Shore/Peoples Gas Ex. RJA-2.3, page 1 of 4, line no. 30
Line No. 3: North Shore/Peoples Gas Exhibit VG 2.3-PGL, line 2

North Shore Gas Company
Comparison of Staff Cost of Service with Company Cost of Service Study
at Company-proposed Revenue Requirement

Line No.		SC 1N	SC 1H	SC 2	SC 3	SC 5	
1	Staff	$ 498,735	$ 51,319,293	$ 14,748,077	$ 706,569	$ 41,212	
2	Company, with Rider UBA	$ 467,231	$ 50,545,695	$ 14,242,472	$ 475,167	$ 41,321	
3	Plus: Uncollectible Gas Costs	$ 30,379	$ 1,156,575	$ 355,146			
4	Total Company	$ 497,610	$ 51,702,270	$ 14,597,618	$ 475,167	$ 41,321	
5	Difference	$ 1,125	$ (382,977)	$ 150,459	$ 231,402	$ (109)	= Line No. 1 - Line No. 4

Sources:

Line No. 1: ICC Staff Exhibit 19.0, Schedule 19.2-NS, Total Revenue Requirement ***Sub-total***
Line No. 2: North Shore/Peoples Gas Ex. RJA-2.4, page 1 of 4, line no. 30
Line No. 3: North Shore/Peoples Gas Exhibit VG 2.3-NSG, line 2