STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

NORTH SHORE GAS COMPANY	:	
	:	
Proposed General Increase In Rates For Gas Service.	:	No. 07-0241
	:	and
THE PEOPLES GAS LIGHT AND COKE COMPANY	:	No. 07-0242
	:	Consol.
Proposed General Increase In Rates For Gas Service.	:	

INITIAL POST-HEARING BRIEF OF NORTH SHORE GAS COMPANY AND THE PEOPLES GAS LIGHT AND COKE COMPANY

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Dated: October 12, 2007

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PEOPLES GAS LIGHT AND COKE COMPANY**

North Shore Gas Company ("North Shore") and The Peoples Gas Light and Coke Company ("Peoples Gas") (together the "Utilities" or the "Companies"), by their counsel, pursuant to the Administrative Law Judges' Order for a Case Management Plan and Schedule of May 9, 2007, submit this Initial Post-Hearing Brief.

I. INTRODUCTION

A. Summary

These proceedings involve the first requests for general rate increases made by Peoples Gas and North Shore to the Illinois Commerce Commission (the "Commission" or "ICC") since 1995. The need to update the Utilities' rates and riders for the first time in over a decade is clear, proven, and undeniable. Their existing base rates significantly under-recover their prudent and reasonable operating expenses and capital investments incurred in order to provide adequate, safe, and reliable service to their retail customers. The Utilities also have proposed four new Riders and other tariff improvements that reflect their operating environment -- including changed business circumstances and public policy objectives -- and significantly benefit customers. The Commission should approve the Utilities' new and revised tariffs.

1. The Utilities' Existing Base Rates Under-Recover Their Actual Costs of Service

The evidence shows that the Utilities' existing base rates fall far short of allowing them to recover their prudent and reasonable actual costs of service. The Utilities presented the testimony of seven witnesses in support of their rate bases and operating expenses, and they presented the testimony of two additional witnesses to support their costs of capital. Their testimony showed that, based on the actual results from the historical test year used in these proceedings, fiscal year 2006, with appropriate adjustments, **Peoples Gas is experiencing an annual cost under-recovery under its existing base rates** (the "revenue deficiency") **of $94,872,000**, and **North Shore is experiencing an annual cost under-recovery of $3,548,000**. *See, e.g.*, Fiorella Surrebuttal ("Sur."), North Shore and Peoples Gas ("NS-PGL") Exhibit ("Ex.") SF-4.0, 4:68-73; NS-PGL Exs. SF-4.3P and SF-4.3N. (Copies of the latter two exhibits are attached in Appendix A hereto.)

The Commission's Staff ("Staff") and "GCI"[1] have proposed a large number of adjustments to the Utilities' **rate bases and operating expenses**. Peoples Gas and North Shore have agreed with, or, in order to narrow the issues, accepted 20 of those adjustments, and they already are reflected in the revenue deficiency figures set forth above.

The evidence shows that Staff's and GCI's remaining contested adjustments to rate bases and operating expenses are unjustified, and, in many instances, they also are improper,

[1] The Illinois Attorney General's Office (the "AG"), the Citizens Utility Board ("CUB"), and the City of Chicago (the "City") (collectively "GCI") jointly submitted the testimony of three witnesses, except that the City does not support a portion of the testimony of one of those witnesses. CUB and the City ("CUB-City") separately submitted the testimony of one witness that the AG does not sponsor.

inconsistent with recent Orders of the Commission, and/or miscalculated. If the contested adjustments were adopted, they would deny the Utilities' recovery of tens of millions of dollars of their prudent and reasonable annual costs of service. For example:

- Staff has proposed to subtract nearly $40 million from the gross plant in Peoples Gas' rate base based on the faulty premise that Peoples Gas' Hub services are imprudent due to costs exceeding revenues. Staff has miscalculated the costs, which actually are less than the revenues, and ignored that the revenues flow entirely to customers through credits against Peoples Gas' Rider 2 Gas Charges.

- GCI has proposed, and Staff has concurred, to subtract nearly $56 million from Peoples Gas' rate base, and over $7 million from North Shore's rate base, based on their respective "OPEB" (Post-Retirement Benefits Other Than Pensions) liabilities. Yet, they simultaneously refuse to take into account Peoples Gas' net pension asset of $110 million, to which Peoples Gas contributed over $15 million in the test year. The Commission approved recovery, at a debt rate of return, on a utility's recent contribution to a net pension asset in *In re Commonwealth Edison Co.*, ICC Docket No. 05-0597, pp. 28-29 (Order on Rehearing Dec. 20, 2006).

- GCI has proposed (but Staff opposes GCI here) to add a full year of depreciation expense to each utility's Accumulated Reserve for Depreciation, over $43 million as to Peoples Gas and nearly $6 million as to North Shore, thereby reducing their rate bases by the same amounts. The proposed adjustments are inconsistent with test year principles and the Commission's *pro forma* adjustments rule. 83 Ill. Adm. Code Part 287. Moreover, the Commission rejected adjustments like those that GCI proposes in *In re Commonwealth Edison Co.*, ICC Docket No. 05-0597, pp. 12-15 (Order, July 26, 2006), and *In re Commonwealth Edison Co.*, ICC Docket No. 01-0423, pp. 41-44 (Interim Order April 1, 2002) (carried forward to final Order of March 28, 2003).

- Staff has proposed to subtract from rate base nearly $27 million as to Peoples Gas and over $6 million as to North Shore for Gas in Storage for which, it is uncontested, the Utilities paid at least a year ago. These adjustments are based on Staff's unreasonable theory that the Utilities should not recover the amounts they paid because the vendors "financed" that storage gas. The vendors provided "financing" only in the sense that there was up to maximum of 16 days from when the Utilities received the vendors' invoices to when the Utilities paid them over a year ago.

- Staff has proposed to deduct nearly $15 million and over $600,000 of Cash Working Capital from the rate bases of Peoples Gas and North Shore, respectively. Staff's proposal, however, incorrectly and inconsistently treats certain capitalized and expense items.

- Staff has proposed to deduct from rate base over $13 million as to Peoples Gas and over $1 million as to North Shore for working capital in relation to Gas in Storage. The proposed adjustments are based on Staff's theories and calculations on storage volumes, which are inconsistent with the Utilities' actual storage inventory policies.

- Staff and GCI have proposed to disallow all test year employee incentive compensation program costs and expenses, which is $5,376,000 as to Peoples Gas and $576,000 as to North Shore. The evidence shows that all of these costs and expenses are prudent, reasonable in amount, and benefit customers. Staff and GCI propose special grounds for disallowing these prudent costs that do not withstand scrutiny. Moreover, even under their approaches, at a minimum, Peoples Gas and North Shore should be allowed to recover $1,635,000 and $147,000, respectively.

- Staff proposes to disallow collection agency fees of $1,770,000 and $76,000 as to Peoples Gas and North Shore, respectively, on the grounds that the test year levels of these expenses should be used, even though they were abnormally low due to the Gas Charge settlement. The Utilities reasonably propose to use a three year average of fiscal years 2003-2005, which is more representative of the levels of these expenses that will be experienced during the period in which the rates being set in these proceedings will be in effect.

- Staff proposes to disallow injuries and damages expenses of $750,000 and $104,000 as to Peoples Gas and North Shore, respectively, based on a complicated five-year average of accruals and payouts, but Staff did not show that the test year level was outside of the normal range of these expenses. Staff's approaches to normalization of expenses are inconsistent. Moreover, Staff did not justify using a five-year average. Using Staff's methodology, a four-year average would increase the levels of these expenses.

Staff's and GCI's contested adjustments lack merit and should be rejected.

The Utilities, in addition to correctly calculating their costs and expenses, also propose reasonable capital structures for ratemaking purposes, costs of long-term debt, rates of return on common equity ("ROE"), and **overall rates of return** (weighted average costs of capital) ("ROR"). Peoples Gas proposes an ROR of 8.24%, incorporating an ROE of 11.06%. *E.g.*, NS-PGL Ex. BAJ-2.1P. Those figures are reductions from the 9.19% and 11.10%, respectively, approved in Peoples Gas' 1995 rate case. North Shore proposes an ROR of 8.56% and an ROE of 11.06%. *E.g.*, NS-PGL Ex. BAJ-2.1N. Those figures are reductions from the 9.75% and

11.30%, respectively, approved in North Shore's 1995 rate case. The Utilities are entitled, as a matter of constitutional law, to reasonable rates of return of and on their capital investments. *E.g.*, *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1989).

Although there is agreement among the Utilities, Staff, and other parties, on the Utilities' capital structures and costs of long-term debt, Staff and CUB-City propose unreasonable ROEs, lower than any ROE that the Commission has approved for a gas utility in at least 30 years. Moul Sur., NS-PGL Ex. PRM-3.0, 12:255-260. CUB-City's proposed ROEs, in particular, are roughly two hundred basis points lower than those set for other utilities around the country in recent years. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 3:60 – 5:88. No valid application of the market-based cost of equity models can justify such ROEs, the unreasonableness of which is confirmed by comparison to the information relied upon by sophisticated investors.

Rates that do not allow Peoples Gas and North Shore a reasonable opportunity to recover their prudent and reasonable costs of service do not comport with the statutory mandate of just and reasonable rates. 220 ILCS 5/9-201(c); *Business and Professional People for the Pub. Interest v. Illinois Commerce Comm'n,* 146 Ill. 2d 175, 208 (1991) (under Section 9-201, the Commission must "set[] rates which are '*just and reasonable*' not only to the ratepayers but to the utility and its stockholders"). Moreover, the Utilities' continued operation under such rates would not be sustainable over time and, thus, is not in the long-term interests of their customers.

Accordingly, the Commission should establish just and reasonable updated base rates that allow Peoples Gas and North Shore a reasonable opportunity to recover their costs of service, including their operating expenses and reasonable RORs. The Commission should then appropriately allocate those costs among the Utilities' customer classes in a manner that reflects the causation of those costs. Peoples Gas and North Shore proposed such rates in their direct case, and they have improved and further updated them (and accepted certain positions in order to narrow the contested issues) in their rebuttal and surrebuttal testimony. The Commission should approve those rates, as so revised.

2. <u>The Utilities' Proposed New Riders Should Be Adopted</u>

While setting new cost-based rates is the core task in a rate case, the evidence shows that the Utilities' rates and riders also need to be updated because the Utilities and the Commission must address new and increased challenges from the changing business environment for a local distribution company and evolving public policy and ratemaking objectives. These include: (1) weather trending warmer;[2] (2) continued reductions in natural gas usage per customer that accompany warmer weather, the greater emphasis on energy efficiency and conservation measures, and higher gas prices; (3) a volatile gas price environment (that also leads to increases and volatility in customers' bills and increased and uncontrollable uncollectible accounts expenses); (4) increased costs of doing business in an environment of rising costs that affects the Utilities' operating expenses and capital expenditures; and (5) a need to balance the recovery of the Utilities' mostly fixed costs and customers' desire for low and stable bills. *E.g.*, Borgard Direct ("Dir."), PGL Ex. LTB-1.0 REV, 17:373-382; Borgard Dir., NS Ex. LTB-1.0 REV, 16:336-345; Feingold Dir., PGL Ex. RAF-1.0, 6:117 - 7:128; Feingold Dir., NS Ex. RAF-1.0, 5:111 – 6:123.

The continued declines in usage per customer are uncontested. *See, e.g.*,, PGL Ex. LTB-1.2 (residential customers); PGL Ex. LTB-1.3 (Rate 2 General Service customers); NS

[2] The Utilities appropriately have proposed billing determinants calculated using a ten year weather normalization period. They presented compelling supporting testimony regarding the accuracy of this approach, including statistical evidence (Marozas Dir., PGL Ex. BMM-1.0; Marozas Dir., NS Ex. BMM-1.0; Marozas Reb., NS-PGL Ex. BMM-2.0; Marozas Sur., NS-PGL Ex. BMM-3.0) and testimony regarding climate change in general, and the warming trend in the Utilities' service territories in particular, from an independent climate scientist, Dr. Eugene Takle (Takle Dir., PGL Ex. EST-1.0; Takle Dir., NS Ex. EST-1.0; Takle Reb., NS-PGL Ex. EST-2.0; Takle Sur., NS-PGL Ex. EST-3.0).

Ex. LTB-1.2 (residential customers). (Copies of these exhibits are attached in Appendix A hereto.) Moreover, "[e]ach of the [five major] challenges [discussed above] negatively impacts the Company's ability to earn its approved margin revenues, i.e. its cost of service exclusive of purchased gas and flow-through items." Borgard Dir., PGL Ex. LTB-1.0 REV, 17:380-382; Borgard Dir., NS Ex. LTB-1.0 REV, 16:343-345. The decline in the Utilities' margin revenues since 2003 is uncontested, although certain intervenors have presented confused testimony on the subject. *See* Feingold Reb., NS-PGL Ex. RAF-2.0, 8:154 – 10:182; NS-PGL Ex. RAF-2.1 (a copy of the latter exhibit is attached in Appendix A hereto).

Peoples Gas and North Shore have proposed four new riders to address these new and increased challenges. First, they each have proposed a new rider, "Rider VBA", based on their recognition of changed environmental and economic realities, public policy and ratemaking objectives, and the impact of those factors on the gas utility business and the regulatory process. Rider VBA provides for revenue "decoupling" in relation to the Utilities' volumetric charges and thus to the portions of their margin revenues that are intended to be recovered through those charges. Decoupling increasingly is advocated and is being adopted across the country in order to align ratemaking with energy efficiency through the elimination of the incentive utilities have to increase sales and to remove the disincentive they have to decrease sales. The Utilities also have proposed, in the alternative, a new rider, "Rider WNA", that provides for weather normalization in relation to the Utilities' volumetric charges. Rider VBA effectively takes into account all of the factors that affect customer usage and, thus, the amounts recovered per customer on the volumetric charges. Rider WNA only accounts for the effects of weather on customer usage and, thus, for a portion of the amounts recovered per customer through those charges. The Utilities have provided compelling evidence, including testimony from an independent expert, Russell Feingold, a Managing Director of Navigant Consulting (Feingold Dir., PGL Ex. RAF-1.0; Feingold Dir., NS Ex. RAF-1.0; Feingold Reb., NS-PGL Ex. RAF-2.0; Feingold Sur., NS-PGL Ex. RAF-3.0), that supports each of these Riders.

Riders VBA and WNA work fairly in both directions. If usage / weather for the month is more favorable to the Utilities than the baseline levels incorporated into the riders, then customers receive credits on the applicable month's bills. If usage / weather is less favorable, then customers receive appropriate charges.

Staff and certain intervenors oppose both Rider VBA and the alternative Rider WNA, but their arguments amount to little more than urging "traditional ratemaking" for its own sake and claiming that the riders would introduce an incremental measure of complexity and administrative burden for Staff and the Commission. Those arguments do not warrant preserving the *status quo* in the face of the overwhelming evidence, including evidence regarding adoption of such riders in numerous other jurisdictions, that the riders will benefit customers and the Utilities. The Commission should approve Rider VBA or, in the alternative, Rider WNA.

The second rider, "Rider ICR", provides a mechanism for Peoples Gas to recover the costs incurred to accelerate the upgrading of the natural gas infrastructure in the City of Chicago. Peoples Gas has demonstrated the benefits of accelerating the replacement of cast iron and ductile iron main in the City of Chicago. Rider ICR is necessary for Peoples Gas to recover the costs of this valuable infrastructure project.

The third rider, "Rider EEP", also addresses environmental issues by providing a mechanism to recover the costs of an energy efficiency program . The program is developed in collaboration with several intervenors in these proceedings. The program establishes a mechanism to encourage the Utilities' customers to use natural gas more efficiently.

Finally, the Utilities also proposed "Rider UBA". Rider UBA provides for appropriate tracking and recovery of the gas cost portion of the Utilities' uncollectible account expenses.

The evidence, including the testimony of James Schott, Vice President – Regulatory Affairs, Peoples Gas (Schott Dir., PGL Ex. JFS-1.0; Schott Reb., NS-PGL Ex. JFS-2.0; Schott Sur., NS-PGL Ex. JFS-3.0 2REV), regarding Rider ICR, and the testimony of Mr. Feingold, regarding Riders EEP, ICR, and UBA, warrants the approval of these Riders, each of which benefits customers as well as the Utilities. The opposition to these three Riders lacks substance.

3. <u>Other Tariff and Terms and Conditions Issues</u>

The Utilities, in their original filings and over the course of these cases, have proposed and agreed to rate designs and terms and conditions that allocate costs in a manner that appropriately reflects cost-causation, take into account customer bill impacts, are consistent with the safe operation of their systems, and provide for high quality service on just and reasonable terms. North Shore proposed to continue to set all of its service classifications at cost. Grace Dir., NS Ex. VG-1.0 3REV, 5:110 – 6:118. Peoples Gas proposed to continue to set its large volume service classifications at cost and gradually to move its small residential and general service rates toward cost. Grace Dir., PGL Ex. VG-1.0 2REV, 6:111 – 7:158. Both Utilities propose to recover larger portions of their fixed costs (which comprise the vast majority of their non-gas supply costs) through fixed charges than under their existing rates, although very large parts of their fixed costs still will be recovered through volumetric charges, Grace Dir., PGL Ex. VG-1.0 2REV, 8:168 – 9:184; Grace Dir., NS Ex. VG-1.0 3REV, 6:128 – 7:144. The resulting customer charge increases appropriately balance the need for greater recovery of fixed costs through fixed charges with customer bill impacts, *See, e.g.*, Grace Reb., NS-PGL Ex. VG-2.0, 23:480 – 500, 37:807 – 39:857. The Utilities also have proposed significant changes to their small and large volume transportation programs to balance more equitably the rights and obligations of sales and transportation customers. Zack Dir., PGL Ex. TZ-1.0 2REV; Zack Dir., NS Ex. TZ-1.0 REV. In response to comments received from Staff and various intervenors, the Utilities modified some of their more significant changes to ameliorate the effects of the changes on their transportation customers while trying to preserve the more equitable balance they sought to achieve in their original proposals. Zack Reb., NS-PGL Ex. TZ-2.0; Zack Sur., NS-PGL Ex. TZ-3.0.

These proceedings involve a number of contested issues regarding rate design and terms and conditions of service issues, especially, as regards transportation service. Staff, in some instances, and a number of intervenors, in many instances, have proposed other, contested rate design and terms and conditions modifications, changes which lack justification and which, especially as to those intervenors, often come at the expense of other customers. The Commission should not adopt those unwarranted and one-sided proposals.

In connection with its large volume transportation program, Peoples Gas originally proposed the elimination of Rider FST, changes to Rider SST, the merging of Rider LST into Rider SST, and changes to Rider TB and Rider P (Zack Dir., PGL Ex. TZ-1.0 2REV, 1:17-20), and North Shore proposed substantially similar revisions to its large volume transportation program (Zack Dir., NS Ex. TZ-1.0, 1:18-21). However, the underlying reason for each Utility's original proposal was the same: the storage and standby rights of each Utility's transportation customers need to be shaped to be consistent with each Utility's gas supply portfolio. Zack Dir., PGL Ex. TZ-1.0 2REV, 3:49-52; Zack Dir., NS Ex TZ-1.0, 3:50-53. While the Utilities have modified their proposals to some extent as a result of comments from other parties, the underlying reason for each Utility's proposals remains valid.

Each Utility also proposed revisions to its small volume transportation program, now commonly known as Choices For You℠ ("CFY"). Each Utility proposed to eliminate enrollment limitations associated with the CFY program, to simplify enrollment, to increase Rider CFY's monthly delivery tolerance, to move the billing of the Aggregation Balancing Gas Charge from the supplier to the customer at the account level, and to incorporate certain other program enhancements that will be described in more detail below. Zack Dir., PGL Ex. TZ-1.0 2REV, 23:527-532, 31:717-32:725; Zack Dir., NS. Ex. TZ-1.0, 22:500-505, 690-698.

The Commission should approve Peoples Gas' and North Shore's proposed new and revised rates and riders, subject to the modifications they proposed or accepted in rebuttal and surrebuttal testimony. The Utilities' proposals are just and reasonable.

B. Nature of Operations

1. Peoples Gas

Peoples Gas is a local distribution company engaged in the business of transporting, purchasing, storing, distributing, and selling natural gas at retail to approximately 840,000 residential, commercial, and industrial customers within the City of Chicago. Borgard Dir., Peoples Gas Ex. LTB-1.0 REV, 4:90 - 5:92; Doerk Dir., Peoples Gas Ex. ED-1.0, 3:53-54. This service territory covers an area of about 228 square miles and has a population of approximately three million people. Borgard Dir., Peoples Gas Ex. LTB-1.0 REV, 5:92-93. Peoples Gas employs approximately 1,540 people, virtually all within the City of Chicago. *Id.* at 5:93-94. Peoples Gas is a wholly owned subsidiary of Peoples Energy Corporation, which in turn is a wholly owned subsidiary of Integrys Energy Group, Inc. ("Integrys") *Id.* at 5:95-96.

Peoples Gas' distribution system consists of approximately 4,025 miles of gas distribution mains. Doerk Dir., Peoples Gas Ex. ED-1.0, 3:54-56. It owns approximately

425 miles of gas transmission lines. *Id.* at 3:56. The distribution system is most commonly operated at a pressure range of 0.25 to 25 pounds per square inch, while the transmission system operates at pressures up to 300 pounds per square inch or more. *Id.* at 3:56-59. Peoples Gas also owns a storage field, Manlove Field. *Id.* at 3:59-60.

The physical configuration of Peoples Gas' system is a dispersed/multiple city gate, integrated transmission/distribution and multi pressure-backed system. Doerk Dir., Peoples Gas Ex. ED-1.0, 3:63-64. It is designed to provide gas service to all customers entitled to be attached to the system, to deliver volumes of natural gas to all sales and transportation customers, and to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day. *Id.* at 4:66-69. A gas utility system sized only to accommodate average gas demands would not be able to meet system peak demands. *Id.* at 4:69-71.

2. <u>North Shore</u>

North Shore is a local distribution company engaged in the business of transporting, purchasing, storing, distributing and selling natural gas at retail to approximately 158,000 residential, commercial, and industrial customers within fifty-four communities in Lake and Cook Counties, Illinois. Borgard Dir., North Shore Ex. LTB-1.0 REV, 4:87-90; Doerk Dir., North Shore Ex. ED-1.0, 3:47-49. North Shore employs approximately 200 people, while sharing many administrative facilities owned by Peoples Gas. Borgard Dir., North Shore Ex. LTB-1.0 REV, 4:90-4:92. North Shore is a wholly owned subsidiary of Peoples Energy Corporation, which in turn is a wholly owned subsidiary of Integrys. *Id.* at 5:92-94.

North Shore's distribution system consists of approximately 2,270 miles of gas distribution mains. Doerk Dir., North Shore Ex. ED-1.0, 3:49-50. North Shore owns approximately 95 miles of gas transmission lines. *Id.* at 3:50-51. Its distribution system is most commonly operated at a pressure of 45 pounds per square inch, while the transmission system operates at a pressure of 250 pounds per square inch. *Id.* at 3:51-53. While North Shore does not own any storage fields, it does purchase storage services from Peoples Gas, pursuant to the a storage services agreement, approved by the Commission, and from two interstate pipelines. *Id.* at 3:53-59. In addition, North Shore owns a liquid propane production facility used for peaking purposes. *Id.* at 3:59-60.

The physical configuration of North Shore's system is a dispersed/multiple city-gate, integrated transmission/distribution and multi pressure-based system. Doerk Dir., North Shore Ex. ED-1.0, 3:62-63. It is designed to provide gas service to all customers entitled to be attached to the system, to deliver volumes of natural gas to all sales and transportation customers, and to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day. *Id.* at 4:65-68. A gas utility system sized only to accommodate average gas demands would not be able to meet system peak demands. *Id.* at 4:68-70.

C. <u>Test Year (Uncontested)</u>

The Utilities each proposed their fiscal year 2006, i.e., the twelve months ending September 30, 2006, as their test year. Fiorella Dir., Peoples Gas Ex. SF-1.0, 5:98-99; Fiorella Dir., North Shore Ex. SF-1.0, 5:102-103. The 2006 test year data were based on the Utilities' actual 2006 revenues, expenses, and rate base items, subject to appropriate adjustments. Fiorella Dir., Peoples Gas Ex. SF-1.0, 6:118-120, 7:140-141; Fiorella Dir., North Shore Ex. SF-1.0, 6:122-124, 7:144-145. No party contested the proposed test year, which was ordered by the Commission in *In re WPS Resources Corp., et al.*, ICC Docket No. 06-0540, Appendix, Condition of Approval No. 13 (Order Feb. 7, 2007).

II. RATE BASE

A. Overview

Peoples Gas' final proposed rate base of $1,289,531,000 and North Shore's final proposed rate base of $193,577,000 should be approved by the Commission. The Utilities' rate base figures appropriately and correctly reflect the prudent, reasonable cost, and used and useful investments that they have made in their systems in order to serve their customers.

Peoples Gas, in its rebuttal and surrebuttal testimony, agreed with or, in order to narrow the issues, accepted a number of rate base adjustments proposed by Staff and GCI, resulting in Peoples Gas' final rate base figure of $1,289,531,000. That figure consists of:

- $1,495,173,000 of net plant ($2,429,392,000 of Gross Utility Plant less $934,219,000 of Accumulated Provision for Depreciation and Amortization or "Depreciation Reserve");
- $126,359,000 for three additional items, i.e., Gas in Storage, Materials and Supplies, and Cash Working Capital; and
- $332,001,000 for reductions, mainly Accumulated Deferred Income Taxes.

E.g., NS-PGL Exhibit ("Ex.") SF-4.1P. In its direct case, Peoples Gas had proposed a rate base of $1,308,007,000, consisting of $1,500,600,000 of net plant ($2,434,914,000 of gross plant less $934,314,000 of Depreciation Reserve), plus $126,359,000 for the three items above increasing rate base, less $318,952,000 for items reducing rate base. *E.g.*, PGL Ex. SF-1.1 at Schedule ("Sched."). B-1.

North Shore, in its rebuttal and surrebuttal testimony, also agreed with or, in order to narrow the issues, accepted a number of rate base adjustments proposed by Staff and GCI, resulting in North Shore's final rate base figure of $193,577,000. That figure consists of:

- $229,779,000 of net plant ($378,350,000 of gross plant less $148,571,000 of Depreciation Reserve);
- $10,922,000 for three additional items, i.e., Gas in Storage, Materials and Supplies, and Cash Working Capital; and
- $47,124,000 for reductions, mainly Accumulated Deferred Income Taxes.

E.g., NS-PGL Ex. SF-4.1N. In its direct case, North Shore had proposed a rate base of $197,107,000, consisting of $231,444,000 of net plant ($380,087,000 of gross plant less $148,643,000 of Depreciation Reserve), plus $10,922,000 for the three items increasing rate base, less $45,259,000 for items reducing rate base. *E.g.*, NS Ex. SF-1.1 at Sched. B-1.

Staff and GCI propose lower rate base figures for the Utilities, but their numbers are the products of their respective underlying contested rate base adjustments, which lack merit and should not be approved. Staff proposes Peoples Gas and North Shore rate bases of $1,170,329,000 and $181,328,000, while GCI proposes Peoples Gas and North Shore rate bases of $1,215,362,000 and $184,880,000, respectively. Hathhorn Reb., Staff Ex. 13.0, Scheds. 13.3 P and 13.3 N; GCI Ex. 5.1, Sched. B Rev.; GCI Ex. 5.2, Sched. B Rev.[3] Staff's and GCI's contested rate base adjustments are incorrect and, in some instances, also are improper, one-sided, or seriously miscalculated, and, therefore, should not be approved, as is shown in Sections II(C) through II(G), III(C)(3)(b), and V of this Initial Brief, *infra*. Accordingly, the Commission should approve a rate base of $1,289,531,000 for Peoples Gas and a rate base of $193,577,000 for North Shore.

[3] The referenced Staff exhibit actually states a rate base figure of $1,159,924,000 as to Peoples Gas, but that figure does not reflect an additional uncontested amount of $10,405,000, and, therefore, the Staff rate base figure for Peoples Gas in the text above has been updated by adding that $10,405,000. See Section II(B)(2) of this Initial Brief, *infra*; NS-PGL Ex. SF-4.7P (Staff response to NS-PGL data request 8.08) The referenced GCI exhibits state rate base figures for the Utilities that need to updated for similar reasons, but the GCI rate base figures in the text above have not been updated because the differences are much smaller. See Section II(B)(2).

B. Uncontested Issues

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

Staff witness Mr. Kahle's proposal, that the Commission's final Order include an original cost determination as to each utility, is uncontested. Mr. Kahle proposed that the Order make such determinations, pursuant to 83 Ill. Adm. Code Part 510 and its Appendix A, regarding Peoples Gas' and North Shore's Gross Utility Plant balances as of the end of the test year, fiscal year 2006, i.e., as of September 30, 2006. Kahle Corr. Reb., Staff Ex. 15.0, 21:443 – 22:459, 22:473-479. He recommended that the Order state in part:

> It is further ordered that the $2,327,990,00 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.

Kahle Corr. Reb., Staff Ex. 15.0, 21:455 – 22:459, 22:473-479. The Utilities submitted testimony agreeing with Mr. Kahle's proposal. Kallas Sur., NS-PGL Ex. LMK-3.0, 5:109 – 6:114. No witness opposed it. Mr. Kahle's proposed language should be included in the Findings and Ordering section of the final Order.

2. *Pro Forma* Capital Additions[4]

Staff witness Mr. Kahle's final revised figures for the amounts of the Utilities' *pro forma* adjustments to rate base for post-test year capital additions are uncontested. Peoples Gas and North Shore originally proposed *pro forma* adjustments, for post-test year capital additions reasonably expected to be placed in service no later than February 2008, in the gross amounts of $104,524,000 and $10,645,000, respectively. *E.g.*, Fiorella Dir., PGL Ex. SF-1.0, 18:384 –

[4] As indicated above, the Utilities agreed with or, in order to narrow the issues, accepted the Staff and GCI proposed adjustments discussed in Section II(B)(2) through II(B)(5) of this Initial Brief, *infra*. The Utilities have not waived their right to pursue these issues in future rate proceedings.

19:402; PGL Ex. SF-1.1, Schedules ("Scheds.") B-1, column [E], B-2, column [B], and B-2.1; Fiorella Dir., NS Ex. SF-1.0, 17:373 – 18:391; NS Ex. SF-1.1, Scheds. B-1, column [E], B-2, column [B], and B-2.1. Mr. Kahle's final revised figures for the *pro forma* adjustments for capital additions consist of the amounts he suggested in his rebuttal testimony plus an additional $10,405,000 of Peoples Gas' cushion gas additions he supported in a subsequent data request response (in evidence), i.e., gross amounts of $95,697,000 as to Peoples Gas and $8,908,000 as to North Shore. Kahle Corr. Reb., Staff Ex. 15.0, 14:291 – 16:335; Fiorella Sur., NS-PGL Ex. SF-4.0, 5:108 – 6:124; NS-PGL Ex. SF-4.7P. The Utilities do not contest Mr. Kahle's final revised figures. Fiorella Sur., NS-PGL Ex. SF-4.0, 5:108 – 6:124. The Utilities' understanding is that GCI, which supported somewhat higher figures here of $96,411,000 and $10,116,000, respectively (Effron Reb., GCI Ex. 5.0, 2:45 – 3:59; GCI Ex. 5.1, Sched. B-1 Rev.; GCI Ex. 5.2, Sched. B-1 Rev.), does not contest Mr. Kahle's final revised figures. No other witness presented any other figures. Mr. Kahle's final revised figures should be approved.[5]

3. <u>Capitalized Lobbying Expenses</u>

Please see Section III(B)(5)(d) of this Initial Brief, *infra*.

4. <u>Capitalized City of Chicago Resurfacing Costs (PGL)</u>

Please see Section III(B)(2)(c) of this Initial Brief, *infra*.

5. <u>ADIT - Gas Cost Reconciliation</u>

GCI witness Mr. Effron's proposed adjustments to Accumulated Deferred Income Taxes ("ADIT") related to gas cost reconciliation are uncontested. The proposed adjustments increase

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[5] As noted in Section II(A) of this Initial Brief, *supra*, Staff's overall rate base figure for Peoples Gas, and GCI's overall rate base figures for Peoples Gas and North Shore, as presented in their respective rebuttal testimony, do not reflect Mr. Kahle's final revised figures for the two *pro forma* adjustments discussed here and, therefore, those three overall rate base figures need to be updated.

ADIT, and thus reduce rate base, by the amounts of $5,748,000 as to Peoples Gas and $1,142,000 as to North Shore. Effron Dir., GCI Ex. 2.0, 14:295-312, 16:350 – 17:379 and Sched. B-2. The Utilities do not contest the proposed adjustments. Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:109; PGL Ex. SF-2.2P, column [E]; NS Ex. SF-2.2N, column [D]. No witness opposed the proposed adjustments.

6. [ADIT -] AMT - Gas Charge Settlement

GCI witness Mr. Effron's proposed adjustments to Alternative Minimum Taxes ("AMT"), and thus to ADIT, related to the gas charge settlement are uncontested. The proposed adjustments increase ADIT, and thus reduce rate base, by $7,820,000 as to Peoples Gas and $773,000 as to North Shore. Effron Dir., GCI Ex. 2.0, 14:298-312, 14:314 – 16:348 and Sched. B-2. The Utilities do not contest the proposed adjustments. Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:110; PGL Ex. SF-2.2P, column [F]; NS Ex. SF-2.2N, column [E]. No witness opposed the proposed adjustments.

C. Plant

1. Capitalized Incentive Compensation

Please see Section III(C)(3)(b) of this Initial Brief, *infra*.

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

D. Reserve for Accumulated Depreciation and Amortization

1. GCI's Proposed Adjustments

Peoples Gas and North Shore correctly calculated the amounts for their Depreciation Reserves that should be subtracted from gross plant when calculating their rate bases. They properly started with the Depreciation Reserve amounts as of the end of the test year, fiscal year 2006, i.e., as of September 30, 2006, and then made the correct adjustments needed to reflect the impacts of their proposed adjustments to plant, including their *pro forma* adjustments for post-test year capital additions.[6] Fiorella Dir., PGL Ex. SF-1.0, 9:192-197, 14:306 – 15:321, 18:377-394; PGL Ex. SF-1.1, Sched. B-1, line 2, Sched. B-2, column [B], Sched. B-2.1, Sched. B-6; Fiorella Dir., NS Ex. SF-1.0, 9:196-201, 14:304 – 15:318, 17:366 – 18:383; NS Ex. SF-1.1, Sched. B-1, line 2, Sched. B-2, column [B], Sched. B-2.1, Sched. B-6.

The Commission should reject the adjustments to the Depreciation Reserves proposed by GCI witness Mr. Effron. Effron Dir., GCI Ex. 2.0, 5:96 – 8:176, 10:210 – 12:252; Effron Reb., GCI Ex. 5.0, 3:62 – 6:142. While he asserts that his proposed adjustments somehow are justified by the Utilities' proposed *pro forma* adjustments for post-test year capital additions, he does not and cannot claim that the Utilities have incorrectly calculated the impacts of those adjustments on the Depreciation Reserves. Rather, he inappropriately and incorrectly seeks to use those adjustments as an excuse to add another year of depreciation to the Depreciation Reserve. The additional full year of depreciation applies to all utility gas plant in service, not just the depreciation applicable to the *pro forma* capital additions for which the Utilities already correctly have accounted, as noted above. Fiorella Reb., NS-PGL Ex. SF-2.0, 9:196 – 11:227; Fiorella Sur., NS-PGL Ex. SF-4.0, 8:163 – 9:187. Staff agrees with the Utilities that Mr. Effron's proposed adjustments are inappropriate and incorrect for that reason, i.e., switching test years for the Depreciation Reserve values. Kahle Corr. Reb., Staff Ex. 15.0, 17:346-359.

Mr. Effron's proposal also is unfair, because it does not move forward to a 2007 value, rather than a test year value, other items which would increase the Utilities' revenue requirements. Fiorella Reb., NS-PGL Ex. SF-2.0, 10:214-222. Mr. Effron's rejoinders, that the ADIT value likely would increase in 2007 and "there is no reason to believe that the other

[6] The Utilities' *pro forma* adjustments for post-test year capital additions are discussed in Section II(B)(2) of this Initial Brief, *supra*.

components [of rate base besides net plant and ADIT] would change materially from the test year to 2007" (Effron Reb., GCI Ex. 5.0, 3:78 - 4:83), miss the point about inappropriately and unfairly deviating from test year principles.

Mr. Effron's proposed adjustment, which is based on adding another year of depreciation expense to the Depreciation Reserves, also should be rejected because it fails to meet the criteria for *pro forma* adjustments. The proposal does not meet the "known and measurable" criteria of 83 Ill. Adm. Code § 287.40, as Staff's witness also pointed out. Kahle Corr. Reb., Staff Ex. 15.0, 17:355-357. The proposal also is based on attrition, contrary to the attrition and inflation language of 83 Ill. Adm. Code § 287.40, which Mr. Effron himself invoked when opposing the Utilities' proposed *pro forma* adjustments for inflation in non-payroll expenses, which the Utilities later withdrew. Effron Dir., GCI Ex. 2.0, 26:586 – 27:595 (mistakenly citing the predecessor provision of 83 Ill. Adm. Code § 287.40 in Part 285 of the Commission's rules prior to the 2003 amendments); *see also* Section III(B)((2)(a) of this Initial Brief, *infra*.

The Commission rejected adjustments like those that Mr. Effron proposes in *In re Commonwealth Edison Co.*, ICC Docket No. 05-0597 (Order, July 26, 2006), at pp. 12-15, and *In re Commonwealth Edison Co.*, ICC Docket No. 01-0423 (Interim Order April 1, 2002), at pp. 41-44) (carried forward to final Order of March 28, 2003)). While Mr. Effron claimed that his proposal finds support in other Commission Orders, the facts of the instant proceeding are like those of the two cases cited above, not like the ones that Mr. Effron cites where the Utilities had no increase in net plant. *E.g.*, Fiorella Reb., NS-PGL Ex. SF-2.0, 10:220-227; Fiorella Sur., NS-PGL Ex. 4.0, 8:163-182.

While the Commission should reject Mr. Effron's proposed adjustments to the Depreciation Reserves in their entirety, it also should be noted that his proposal miscalculates the

Utilities' costs of removal, because it does not comport with how the Utilities account for these costs. He erroneously proposes to deduct amounts for costs of removal from the Depreciation Reserves when, instead, they should be added to depreciation expenses, which would increase the revenue requirements, and he also has his figures wrong. Fiorella Reb., NS-PGL Ex. SF-2.0, 11:228 – 12:249; Fiorella Sur., NS-PGL Ex. SF-4.0, 9:188 – 10:209 (also noting that the Commission has accepted the Utilities' accounting for costs of removal over several decades).

2. Derivative Adjustments

Other than GCI's incorrect proposed adjustments to the Utilities' Depreciation Reserves, discussed in Section II(D)(1) of this Initial Brief, *supra*, Staff and intervenors have not proposed any independent adjustments to the Depreciation Reserves as such. All of Staff's proposed adjustments to the Depreciation Reserves are entirely derivative of Staff's proposed adjustments to plant and to the now uncontested revised *pro forma* adjustments for post-test year capital additions, as is shown in Staff's Schedules. Hathhorn Reb., Staff Ex. 13.0, Sched. 13.4 N, line 2, and Sched. 13.4 P, line 2. GCI's only other proposed adjustments to the Depreciation Reserves also are based on the now uncontested *pro forma* adjustments for post-test year capital additions, as is shown in GCI's Schedules. GCI Ex. 5.1, Sched. B-1 Rev. and Sched. B-2 Rev.; GCI Ex. 5.2, Sched. B-1 Rev. and Sched. B-2 Rev. Accordingly, the Commission's final Order, as to the Depreciation Reserves, need only make derivative calculations, if any, depending on whether it approves any of Staff's contested proposed adjustments to plant.

E. Cash Working Capital

North Shore and Peoples Gas propose that their cash working capital ("CWC") requirements be recalculated using the gross lag methodology and the revenue and expense levels the Commission approves in this consolidated docket. The Utilities further propose that the Commission should authorize them to: (i) exclude capitalized payroll and payroll-related expenses from their CWC calculations; (ii) uniformly consider all Taxes Other Than Income Taxes, dollar-weighting each such tax; (iii) use pass through taxes solely to calculate expense lead times; and (iv) incorporate into their calculations all uncontested, utility-sponsored methodological proposals.[7]

CWC, which is the amount of cash a company requires to finance its day-to-day operations, can be calculated using either of at least two methodologies: the net lag methodology or the gross lag methodology. Adams Dir., NS Ex. MJA-1.0, 3:54-56, 3:63 - 4:65, 18:372-374, 18:388-389; Adams Dir., PGL Ex. MJA-1.0, 3:63 - 4:66, 19:395-397 and 19:411-412; Adams, Transcript ("Tr.") at 282:6-19; Kahle Dir., Staff Ex. 3.0, 3:55 - 4:63; Kahle Corr. Reb., Staff Ex. 15.0, 10:197-198. Irrespective of the methodology utilized, calculating a utility's CWC requirement requires consideration of its cash transactions, more specifically, its revenues and expenses, and the timing differences between the utility's collection of revenues and its payment of expenses. *See* Adams Dir., NS Ex. MJA-1.0, 3:52-53 and 61-63; Adams Dir., PGL Ex. MJA-1.0, 3:52-53 and 3:61-63; Adams Reb., NS-PGL Ex. MJA-2.0, 4:82-84; Kahle Dir., Staff Ex. 3.0, 3:49 - 4:63. In these proceedings, the Utilities have agreed to calculate their CWC requirements using the gross lag methodology utilized by Staff (Kahle Dir., Staff Ex. 3.0, 4:66-68), rather than the net lag methodology they used to calculate the CWC requirements included in their initial filings. Adams Reb., NS-PGL Ex. MJA-2.0, 4:72-77; Adams Sur., NS-PGL Ex. MJA-3.0, 4:82-84 and 6:116-18; Adams, Tr. at 283:9-12.

[7] It is uncontested that the expense lead time associated with North Shore's payments for natural gas should be consistent with the expense lead time determined for North Shore, not that for Peoples Gas. Adams Reb., NS-PGL Ex. MJA-2.0, 12:248-260; Kahle Corr. Reb., Staff Ex. 15.0, 6:112-115, 13:270-274. The Utilities' proposed treatment of uncollectibles also is uncontested. *See* footnote 8, *infra*.

Using the gross lag methodology requires maintaining a balance between revenues and expenses. Adams Reb., NS-PGL Ex. MJA-2.0, 4:85 - 5:107; Adams Sur., NS-PGL Ex. MJA-3.0, 5:104-108, 7:138-141; *see* Adams, Tr. 299:17-21, 309:18 - 310:4. Absent such a balance, the result of the calculation will not accurately reflect a utility's daily cash requirements. *Id.*[8] Because Staff's analyses fail to maintain the required balance and include certain additional errors (Adams Reb., NS-PGL Ex. MJA-2.0, 2:25-29, 5:91-107, 10:208-215), the Commission should order the Utilities to recalculate their CWC requirements in accordance with the Utilities' proposed corrections to Staff's calculations. *See* Adams Sur., NS-PGL Ex. MJA-3.0, 6:120-122. Further, to ensure that the CWC calculations are based on appropriate cash transactions, the revenue and expense levels the Commission approves in this consolidated docket should be reflected in the calculations. Adams Reb., NS-PGL Ex. MJA-2.0, 2:29-31, 3:48-50.

1. <u>Exclusion of Capitalized Expenses</u>

Staff witness Mr. Kahle correctly defines a CWC requirement as "the amount of cash a company needs to keep on hand to meet its cash *operating expenses* after taking into account its cash revenues". Kahle Dir., Staff Ex. 3.0, 3:51-53 (emphasis added); *see* Adams Sur., NS-PGL Ex. MJA-3.0, 13:254-255 (CWC calculations are "intended to reflect the timing of receipt of revenues and payment of *operating expenses*") (emphasis added). Thus, capitalized expenses, which are separate and distinct from operating expenses, should not be included in CWC calculations. Adams Reb., NS-PGL Ex. MJA-2.0, 7:146-49; Adams Sur., NS-PGL Ex. MJA-3.0, 13:253, 13:270-272, 14:289-296. The Commission's decision in Illinois Power Company's

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[8] For example, excluding uncollectibles from revenues but not from expenses would result in an imbalance between the two and an inaccurate determination of the Utilities' true CWC requirements. *See* Adams Reb., NS-PGL Ex. MAJ-2.0, 9:188-192. Accordingly, Staff agreed that the Commission should adopt the Utilities' position that their CWC calculations should exclude uncollectibles. *See* Kahle Corr. Reb., Staff Ex. 15.0, 6:112-115, 13:270-274.

petition for approval of Delivery Services Implementation Plan and Delivery Services Tariffs, ICC Docket Nos. 99-0120/99-0134 (Cons.) (Order August 25, 1999), pp. 63-64, plainly illustrates this point. In those cases, which Staff here relied on, the Commission approved Staff's proposed adjustment to the inventory portion of materials and supplies (*i.e.*, the portion constituting a capitalized expense, Kahle, Tr. at 1159:9-13) only because it was not already reflected in the expense portion of materials and supplies (*i.e.*, the portion constituting an operating expense) and thus not included in the cash working capital allowance. Kahle, Corr. Supp. Dir., Staff Ex. 3.0, 4:76-81; Kahle, Tr. at 1160:10-21. As the Commission explained, if the adjustment had impacted operating expenses, it would have resulted in improper double counting. Kahle, Corr. Supp. Dir. Staff Ex. 3.0, 4:77-80.

Capitalized expenses also should be excluded from CWC calculations because including them in such calculations would improperly distort rates of return. To allow investors to earn a return on capital investments, capitalized expenses are included in rate base. *See* Adams Reb., NS-PGL Ex. MJA-2.0, 7:148-49 and 9:182-83. If capitalized expenses were also included in CWC calculations, such expenses would effectively be included in rate base twice since CWC requirements are used to adjust rate base. *See* Adams Reb., NS-PGL Ex. MJA-2.0, 9:182-84; Adams Sur., NS-PGL Ex. MJA-3.0, 13:255-256 ("Capital expenditures were not included in the [Companies' CWC] analyses because such costs were considered elsewhere in rate base."); Adams, Tr. at 301:5-10; Kahle, Corr. Supp. Dir., 4:64-67 (noting that cash working capital adjusts rate base but "does not affect the value of other components of rate base"); Kahle Corr. Reb., Staff Ex. 15.0, 10:199-200.

Further, including capitalized expenses in CWC calculations, without correspondingly increasing revenues, creates an imbalance between revenues and expenses. *See* Adams Reb., NS-PGL Ex. MJA-2.0, 5:99-104, 8:159-161; Adams Sur., NS-PGL Ex. MJA-3.0, 11:223-232 and 303-308 (*see also* footnote 8, *supra*, re uncollectibles). Thus, Staff's inclusion in its analyses of select capitalized expenses, *i.e.*, solely those capitalized expenses relating to payroll (Kahle, Tr. at 1156:8-22; Adams Reb., NS-PGL Ex. MJA-2.0, 8:171-175; Adams Sur., NS-PGL Ex. MJA-3.0, 13:265-269), is inappropriate. Adams Reb., NS-PGL Ex. MJA-2.0, 8:163-168. The mere fact that Staff perceives capitalized payroll-related expenses to have a short expense lead time is not an appropriate rationale for including those capitalized expenses in its CWC analyses. *See* Adams Reb., NS-PGL Ex. MJA-2.0, 8:175-177.

Accordingly, consistent with Staff's general recognition that CWC calculations should not include capitalized expenses (*see* Kahle, Tr. at 1156:8-22; Adams Reb., NS-PGL Ex. MJA-2.0, 8:171-175; Adams Sur., NS-PGL Ex. MJA-3.0, 13:265-269), the Commission should reject Staff's contention that the Companies' CWC calculations should include the capitalized portion of payroll and payroll-related expenses. *See* Kahle, Corr. Reb., Staff Ex. 15.0, 9:190-193; Kahle, Tr. at 1158:7-13.

2. **Real Estate Taxes**

The Utilities advocate consistent treatment of all Taxes Other Than Income Taxes. *See* Adams Sur., NS-PGL Ex. MJA-3.0, 18:365-170 and 19:398-401; Adams, Tr. at 302:20 - 303-18. With the exception of real estate taxes, the propriety of this principle is undisputed. Adams Reb., NS-PGL Ex. MJA-2.0, 11:226-233; Adams Sur., NS-PGL Ex. MJA-3.0, 15:365-370, 18:382-386, 19:392-394. Regarding real estate taxes, Staff argues that disparate treatment is appropriate because real estate taxes have a relatively longer lead time. Kahle Corr. Reb., Staff Ex. 15.0, 11:217-219. This, however, does not justify disparate treatment, which Staff implicitly recognizes by its failure to advocate such treatment for taxes with relatively short lead times.

Kahle, Tr. at 1168:7-16. Separating real estate taxes from other non-income taxes, and thereby failing to dollar weight them, inappropriately affords real estate taxes disproportionate impact on the CWC calculation as compared to all other dollar-weighted, non-income taxes. Adams Reb., NS-PGL Ex. MJA-2.0, 11:233-237; Adams Sur., NS-PGL Ex. MJA-3.0, 19:387-390; Adams, Tr. at 302:2 - 303:18, 305:3-8.

Notably, in prior proceedings where North Shore and Peoples Gas witness Mr. Adams appears, at least superficially, to have treated real estate taxes separately from other non-income taxes, closer examination shows that he did not in fact do so. Adams Sur., NS-PGL Ex. MJA-3.0, 18:371-376; Adams, Tr. at 287:5 - 288:10, 307:20 - 308:7. Rather, in those cases, Mr. Adams merely utilized a different manner of presenting his analyses of non-income taxes. *Id.* Mr. Adams' method of calculating and dollar-weighting such taxes was exactly the same in those proceedings as it is in this one. Adams Sur., NS-PGL Ex. 3.0, 18:371-381; Adams, Tr. at 307:20 - 308:7. The Commission should adopt the Companies' treatment of non-income taxes.

3. <u>Pass Through Taxes</u>

Because of the timing differences between the dates pass through taxes are assessed and the dates they are paid – and their consequent and indisputable impact on cash flow – it is clear that pass through taxes should be taken into account when determining the expense lead time of Taxes Other Than Income Taxes. Adams Sur., NS-PGL Ex. MJA-3.0, 20:413-417; Adams, Tr. at 290:7-15; *see* Kahle, Tr. at 1164:9-15. By using the same expense lead times that the Companies used, Staff implicitly recognizes this point. Adams, Tr. at 305:19-306:3. In contrast, because the Companies do not bear ultimate responsibility for pass through taxes, it is not appropriate to include the expense dollars represented by such taxes in CWC calculations, and, as Staff recognized, the Companies did not do so. *See* Adams, Tr. 290:10 -291:1 and 291:17-21;

Kahle, Corr. Reb., Staff Ex. 15.0, 11:230-233; Kahle, Tr. at 1165:5-15. Accordingly, the Commission should adopt the Companies' proposed treatment of pass through taxes.

As demonstrated above, using the gross lag methodology to calculate the Companies' CWC requirements, after implementing the foregoing corrections and incorporating the revenue and expenses levels the Commission approves in this docket, will result in an accurate determination of the CWC requirements. The Commission should adopt the Companies' recommendations regarding the recalculation of their CWC requirements.

F. **<u>Gas in Storage</u>**

The Utilities correctly calculated their Gas in Storage to be included in rate base. Peoples Gas correctly included $86,667,000 of Gas in Storage, and North Shore correctly included $10,507,000 of Gas in Storage, based on 13 month averages as of the end of the test year, fiscal year 2006, i.e., as of September 30, 2006. *E.g.,* Fiorella Dir., PGL Ex. SF-1.0, 15:322 – 16:334; PGL Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]; Fiorella Dir., NS Ex. SF-1.0, 15:319-332; NS Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]. Staff's proposed adjustments relating to Gas in Storage lack merit and should not be approved, as is shown below.

1. **<u>Working Capital</u>**

The cost of the Utilities' gas sold to customers is recovered through the purchased gas adjustment rider as the gas is withdrawn from the storage field and sold to customers. However, most stored gas is injected during the non-winter months, so there is a lag between the time the gas is purchased by the utility and injected into storage, and when it is sold. A utility, therefore, has a working capital allowance in rate base for the value of its working gas in storage. As noted above, Peoples Gas' working capital allowance for Gas in Storage is $86,667,000, and North Shore's is $10,507,000 based on the applicable 13 month averages as of the end of the test year.

Staff, through its witness, as revised in his rebuttal testimony, recommended a cost disallowance equivalent to about 6.9 Bcf of gas for Peoples Gas and about 0.9 Bcf for North Shore. Lounsberry Reb., Staff Ex. 23.0, Scheds. 23.1N and 23.1P. His primary argument was that because Peoples Gas had more gas in inventory at the end of the year than during the two prior years and also previous years, the difference should be disallowed, although he also asserted other grounds. *See* Lounsberry Dir., Staff Ex. 11.0, 6:107 – 7:121, *et seq*.

The difference between the test year and the previous two years was primarily weather. The winter in early 2006 was exceptionally warm, so Peoples Gas did not pull as much gas out of storage to meet customer needs. Zack Reb., 74:1636-1646. As Staff concedes, a utility does not necessarily cycle all of its working gas, depending on how cold the winter is. D. Anderson, Tr. at 473:11-18. If a utility injected more gas into an aquifer like Manlove field than it withdrew the previous season, then it would wind up with more gas underground than it had before. D. Anderson, Tr. at 473:19 - 474:1.

The discrepancy that Staff's witness perceived – that Peoples Gas had an inventory at Manlove higher than its planned withdrawals for the following season – is not a genuine issue. All gas stored underground is either base gas or top gas (or to use the alternative terms, all gas is either cushion gas or working gas). D. Anderson, Tr. at 469:14 - 470:5. It can be difficult at any particular time to determine how much is base gas versus top gas, and studies are occasionally done to make the determination. D. Anderson, Tr. at 472:7-15. However, all the gas stored underground is one or the other. Until the study is made, at which time a quantity of top gas is reclassified (and thus capitalized) as base gas, the Utilities record the gas on their books as part of their top gas, or working inventory. Zack Sur., PGL/NS Ex.-TEZ 3.0, 37:811-823.

The fact that they do not in fact cycle all of the gas does not mean the gas does not exist or that the Utilities should not recover a return of and on their investment in it. If it is top gas, then it is properly working capital and included in rate base; if it is base gas, then it is still properly part of rate base (as part of net plant in accordance with the Uniform System of Accounts). *See, e.g.*, Fiorella Dir., PGL Ex. SF-1.0, 11:224-236, Fiorella Dir., NS Ex. SF-1.0, 11:228-238. In no event, should it be a disallowance.

2. **Accounts Payable**

The Utilities correctly did not include any offset for accounts payable in their Gas in Storage figures. Staff's proposed adjustments to impose accounts payable offsets against the Gas in Storage in rate base are unjustified and should be rejected.

Staff's claim is that there should be deductions of $26,727,000 from Peoples Gas' Gas in Storage in rate base and $6,098,000 from North Shore's Gas in Storage in rate base, based on the theory that vendors "financ[ed] these purchases" and, therefore: "The storage gas included in each rate base should be reduced by the related amounts of accounts payable because the Companies should not earn a return on the storage gas until it has been funded by investors." Kahle Corr. Supplemental ("Supp.") Dir., Staff Ex. 3.0 Supp., 2:37-42.

Staff's claim is incorrect. North Shore and Peoples Gas witness Mr. Fiorella provided uncontradicted testimony that the Utilities paid for the Gas in Storage in rate base, and that there are no accounts payable for the Gas in Storage in rate base because, under the applicable standard contract, the Utilities paid for this storage gas within no more 16 days from the receipt of the invoices from the vendors. Fiorella Supp. Reb., NS-PGL Ex. 3.0, 2:22-42. Thus, quite simply: "The item in question, gas storage inventory balances, is based on historical costs, which have been paid for and financed by the Utilities." *Id.* at 4:71-73. As noted earlier, the Utilities'

Gas in Storage in rate base is based on 13 month averages as of the end of the test year, fiscal year 2006, i.e., as of September 30, 2006. *E.g.*, Fiorella Dir., PGL Ex. SF-1.0, 15:322 – 16:334; PGL Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]; Fiorella Dir., NS Ex. SF-1.0, 15:319-332; NS Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]. Hence, the accounts payable relating to the Gas in Storage in rate base were paid, at least, over a year ago, and in each instance they were paid no more 16 days from when the Utilities received the invoices from the vendors. As noted above, Staff's witness himself stated that "the Companies should not earn a return on the storage gas until it has been funded by investors." Kahle Corr. Supp. Dir., Staff Ex. 3.0 Supp., 2:40-42. The fact is, however, that the Gas in Storage in rate base is fully funded by investors -- it has been for over a year.

Staff's witness' rebuttal testimony does not deny that the accounts payable related to the Gas in Storage in rate base have been paid. Instead, Staff's witness offers the revised theory that his proposed adjustments should be approved because Gas in Storage purchased after the test year will be "financed" by vendors. Kahle Corr. Reb., Staff Ex. 15.0, 18:387 - 19:412. However, Staff's witness does not and cannot deny that that "financing" consists of nothing more than the fact that the Utilities pay vendors' invoices for storage gas in no more than 16 days. He does not and cannot deny that the Utilities must, and do, pay those invoices. Staff's position, therefore, unreasonably seeks to deny the Utilities recovery of and on substantial amounts of their actual historical investments in the Gas in Storage in rate base simply because the Utilities do not instantly pay for gas in storage.

Staff's witness cites five Commission Orders that he contends support his position, including the Utilities' 1995 rate cases, but, as he acknowledged, all five involved future test years. Kahle Corr. Reb., Staff Ex. 15.0, 20:413-438. Staff's position, and the application of those five Orders to the instant proceedings, which involve an historical test year, not a future test year, does not fit the facts, is inappropriate, and also unfairly fails to take into account regulatory lag (i.e., the delay between the large cost under-recovery experienced by the Utilities during the test year through the period when the rates will go into effect beginning in 2008). Fiorella Supp. Reb., NS-PGL Ex. SF-3.0, 3:43 – 4:73; Fiorella Sur., NS-PGL Ex. 4.0, 7:138 – 8:160. Staff's proposed adjustments to impose accounts payable offsets against the Gas in Storage in rate base lack merit and should not be approved.

G. OPEB Liabilities and Pension Asset/Liability

GCI's proposed adjustments to subtract other post-employment benefits ("OPEB") liabilities from the Utilities' rate bases, which Staff supported in rebuttal testimony, are incomplete and one-sided and, therefore, should not be approved. In the alternative, GCI's proposed adjustments, if they are approved, should be recalculated to reflect the pension asset of Peoples Gas and the pension liability of North Shore or, further in the alternative, to reflect the test year pension contributions of Peoples Gas and North Shore to the pension plan.

GCI, in direct testimony, proposed to subtract gross amounts of $55,563,000 and $7,094,000 for OPEB liabilities from the rate bases of Peoples Gas and North Shore, respectively, based on the theory that the Utilities' rates set in past cases included amounts intended to cover these expenses and, therefore, the liabilities represent "ratepayer supplied OPEB funds". Effron Dir., GCI Ex. 2.0, 13:272-292. Staff, in rebuttal testimony, subscribed to GCI's proposal and that theory. Pearce Reb., Staff Ex. 14.0, 21:470 – 22:484.

As pointed out by North Shore and Peoples Gas witness Ms. Kallas in her rebuttal testimony, GCI's proposal should not be adopted, because it is inconsistent and unfair in that it excludes Peoples Gas' net pension asset of $110,000,000 and North Shore's net pension liability of $24,000 (both figures are net of ADIT) in the calculation of the Utilities' rate bases. Kallas Reb., NS-PGL Ex. LK-2.0 REV, 13:272-280. GCI's witness, in his rebuttal testimony, included no discussion supporting his proposed OPEB liabilities adjustments or responding to Ms. Kallas's rebuttal testimony on this subject. Effron Reb., GCI Ex. 5.0.

Staff's witness, who addressed this subject for the first time in rebuttal testimony, opposed including the Peoples Gas / North Shore pension asset/liabilities in the calculation of rate base, based on the theory that the asset/liability "was not created with funds supplied by shareholders", but rather by ratepayers, stating that "[t]he related pension asset and liability did not result from any additional contributions on the part of shareholders; accordingly, they are not entitled to a return on these amounts." Pearce Reb., Staff Ex. 14.0, 22:486-502.

Staff's theory is incorrect. Ms. Kallas, in surrebuttal testimony, pointed out that Peoples Gas and North Shore already served a response to a Staff data request on this subject, noting in that response that in the test year, fiscal year 2006, Peoples Gas and North Shore contributed $15,278,614 and $1,862,247, respectively, to the pension plan. Kallas Sur., NS-PGL Ex. LMK-3.0, 3:55-57. Moreover, ratepayers have benefited from those contributions. In calculating their proposed revenue requirements, the levels of pension expense in the test year was reduced by the Utilities' *pro forma* adjustments to reflect the lower level in fiscal year 2007, in the gross amounts of $1,277,000 as to Peoples Gas and $490,000 as to North Shore. Fiorella Dir., PGL Ex. SF-1.0, 27:587-589; PGL Ex. SF-1.1, Sched. C-1, column [D], Sched. C-2, p. 1, line 15, and Sched. C-2.15; Fiorella Dir., NS Ex. SF-1.0, 25:556-558; NS Ex. SF-1.1, Sched. C-1, column [D], Sched. C-2, p. 2, line 15, and Sched. C-2.15. To ignore the Peoples Gas pension asset and the Utilities' pension plan contributions that were reflected in the calculation of the fiscal year 2006 and 2007 pension expense levels would be incomplete and one-sided.

Staff's witness also stated that, in *In re Commonwealth Edison Co.*, ICC Docket No. 05-0597, the Commission's Order of July 26, 2006, disallowed a pension asset in rate base (Pearce Reb., Staff Ex. 14.0, 24:532-535), but, while that statement is correct, it also is incomplete. In that rate case, while the pension asset was not included in rate base, the Commission's Order on Rehearing of December 20, 2006, at pp. 28-29, allowed the utility to recover a rate of return (based on the cost of long-term debt) on a pension plan contribution that it made shortly after the test year, that was funded by an equity contribution from the utility's ultimate parent company, and that was a major factor in a *pro forma* adjustment to reflect a lower level of pension expense in the year after the test year.[9]

GCI's and Staff's position, that OPEB liabilities should be deducted when calculating the Utilities' rate bases, should be rejected, for the reasons stated above. In the alternative, if the OPEB liabilities are to be deducted, then Peoples Gas' net pension asset of $110,000,000 and North Shore's net pension liability of $24,000 also should be incorporated in the calculation of the rate bases. Finally, further in the alternative, if the OPEB liabilities are to be deducted, then, at a minimum, Peoples Gas' contributions of $15,278,614 and North Shore's contributions of $1,862,247 to the pension plan also should be incorporated in the calculation of the rate bases.

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

Other than GCI's two uncontested proposed adjustments discussed in Section II(B)(5) and (6) of this Initial Brief, *supra*, Staff and intervenors have not proposed any independent adjustments to the ADIT as such. All of Staff's proposed adjustments to ADIT are entirely

[9] Staff's witness also noted that inclusion of a pension asset in rate base was denied in two Nicor Gas rate cases, but in both of those cases the pension asset was found to have arisen from appreciation of assets in the pension plan, without any recent contributions to the pension plan. *See* Pearce Reb., Staff Ex. 14.0, 23:515-525; *In re Northern Illinois Gas Co.*, ICC Docket No. 04-0779, pp. 22-23 (Order Sept. 20, 2005).

derivative of Staff's proposed adjustments to other items, as is shown in Staff's Schedules. Hathhorn Reb., Staff Ex. 13.0, Sched. 13.4 N, line 13, and Sched. 13.4 P, line 13. The same is true as to GCI's other proposed adjustments. GCI Ex. 5.1, Sched. B Rev. and Sched. B-2 Rev.; GCI Ex. 5.2, Sched. B Rev. and Sched. B-2 Rev. Accordingly, the Commission's final Order, as to ADIT, need only make derivative calculations, if any, depending on whether it approves any of Staff's or GCI's contested proposed adjustments that have derivative impacts on ADIT.

III. OPERATING EXPENSES

A. Overview

Peoples Gas' and North Shore's final proposed operating expenses figures as shown on their Revised Schedule C-1's (NS-PGL Ex. SF-4.3P and SF-4.3N), to the extent that these expenses are sought to be recovered through the base rate charges to be established in these proceedings, should be approved by the Commission. The Utilities have agreed to or accepted, in order to narrow the issues, a total 18 different adjustments to operating expenses proposed by Staff and GCI, as shown in Section III(B) of this Initial Brief, *infra*. The Utilities' final proposed operating expenses figures appropriately and correctly reflect the prudent and reasonable expenses that they have incurred in order to serve their customers.

Staff proposes five contested adjustments to operating expenses, consisting of their proposed adjustments relating to crankshaft repair expenses (Peoples Gas), Hub services (Peoples Gas), collection agency fees, injuries and damages expenses, and incentive compensation expenses. GCI proposes one contested adjustment to operating expenses, which is supported by cursory testimony that ultimately adopts Staff's contested proposed adjustment related to incentive compensation. There are no other GCI contested proposed adjustments. None of Staff's and GCI's contested proposed operating expenses adjustments are warranted.

All of those adjustments would incorrectly deny the Utilities recovery of expenses that they have incurred in order to serve and benefit their customers. They should be rejected.

B. <u>Uncontested Issues</u>

1. <u>Storage Expenses (Compressor Station Fuel Expenses) (PGL)</u>[10]

GCI witness Mr. Effron's recalculated proposed adjustment to Peoples Gas' operating expenses relating to compressor station fuel expenses is uncontested. Mr. Effron proposed an adjustment to these expenses in his direct testimony. Effron Dir., GCI Ex. 2.0, 31:689 – 32:719. Peoples Gas witness Ms. Kallas responded that Peoples Gas was willing to accept the proposal, but only if it were recalculated based on updated fuel prices and fiscal year 2006 volumes, which results in a $953,000 adjustment (gross amount). Kallas Reb., PG-NGL Ex. LK-2.0, 14:294-309; PGL Ex. LK-2.3. Mr. Effron agreed with that recalculated amount. Effron Reb., GCI Ex. 5.0, 12:283-294. No witness disagreed. Thus, the recalculated adjustment is uncontested.

2. <u>Distribution Expenses</u>

a. <u>Non-Payroll Expenses Inflation</u>

Staff witness Bonita Pearce's and GCI witness Mr. Effron's proposals, to reject the Utilities' *pro forma* adjustments for expected 2007 inflation in non-payroll expenses of $3,084,000 as to Peoples Gas and $542,000 as to North Shore (gross amounts), are uncontested. Ms. Pearce and Mr. Effron cited the Commission's rule regarding *pro forma* adjustments, 83 Ill. Adm. Code § 287.40 (Mr. Effron incorrectly cited the predecessor section of 83 Ill. Adm. Code Part 285 that was replaced in 2003 by 83 Ill. Adm. Code § 287.40), and argued that the proposed adjustments were inconsistent with that rule's provision regarding adjustments based on attrition

[10] As indicated above, the Utilities agreed with or, in order to narrow the issues, accepted the Staff and GCI proposed adjustments discussed in Section III(B)(1) through III(B)(5) and II(B)(7) of this Initial Brief, *infra.* The Utilities have not waived their right to pursue these issues in future rate proceedings.

and inflation factors and that the adjustments were insufficiently particularized to be known and measurable. Pearce Dir., Staff Ex. 2.0, 3:62 – 6:132 and Scheds. 2.1P and 2.1N; Effron Dir., GCI Ex. 2.0, 26:571 – 29:640. The Utilities responded that they were willing to withdraw the proposed *pro forma* non-payroll inflation adjustments as such, but that Peoples Gas was updating its operating expenses figures with new information regarding increases in City of Chicago restoration expenses and personal property taxes that were known and measurable. Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:103 and fn. 2, 12:264 – 13:279, 13:281-290; NS-PGL Exs. SF-2.3P, 2.7P, and 2.8P. The final amounts of those two updates are uncontested, as discussed in Sections III(B)(2)(c) and III(B)(6), *infra*. Accordingly, Staff's and GCI's proposals to reject the *pro forma* adjustments for non-payroll inflation now are uncontested.

b. **Customer Installation Expenses (NS)**

Staff witness Ms. Pearce's proposal, to remove $175,000 of customer installation expenses (gross amount) from North Shore's operating expenses, is uncontested. Pearce Dir., Staff Ex. 2.0, 19:477 – 20:490 and Sched. 2.4 N; Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:104.

c. **City of Chicago Resurfacing Expenses (PGL)**

Peoples Gas' updated *pro forma* adjustment for City of Chicago resurfacing expenses (which has rate base and operating expenses components), as modified by GCI witness Mr. Effron, is uncontested. Peoples Gas proposed the *pro forma* adjustment in direct testimony and updated it in rebuttal testimony. Fiorella Dir., PGL Ex. SF-1.0, 19:403-410, 30:659-667; PGL Ex. SF-1.1, Scheds. B-2.2, C-2.28; Fiorella Reb., NS-PGL Ex. SF-2.0, 12:264 – 13:279; NS-PGL Exs. SF-2.3P and 2.7P. Staff accepted the Peoples Gas rebuttal updates. Kahle Corr. Reb., Staff Ex. 15.0, 21:437-441. GCI proposed, however, to modify the Peoples Gas rebuttal updates. Effron Reb., CGI Ex. 5.0, 12:297 – 14:340. Using the Peoples Gas rebuttal updates as the starting point, the GCI modifications (in gross amounts) reduce rate base (gross plant) by $1,080,000 and operating expenses by $1,620,000. Effron Reb., GCI Ex. 5.0, 13:323 – 14:340 and GCI Ex. 5.1, Sched. C-2.1 Rev. Peoples Gas does not contest those modifications. Fiorella Sur., NS-PGL Ex. 4.0, 6:132-135.

3. <u>Customer Accounts Expenses (Uncollectible Accounts Expenses)</u>

GCI witness Mr. Effron's recalculated proposed adjustments to Peoples Gas' and North Shore's operating expenses relating to uncollectible accounts expenses are uncontested.[11] Mr. Effron proposed adjustments to these expenses in direct testimony. Effron Dir., GCI Ex. 2.0, 20:433-441. Peoples Gas witness Ms. Kallas responded that Peoples Gas was willing to accept the proposals, but only if they were recalculated based on updated fuel prices and fiscal year 2006 volumes, which results in adjustments of $3,283,000 as to Peoples Gas and $103,000 as to North Shore (gross amounts). Kallas Reb., NS-PGL Ex. LK-2.0 REV, 14:294 – 15:313; NS-PGL Ex. LK-2.3. Mr. Effron agreed with the recalculated amounts. Effron Reb., GCI Ex. 5.0, 9:225 – 10:240. No other witness differed. Thus, the recalculated adjustments are uncontested.

4. <u>Customer Service and Information Expenses</u>

a. <u>"Advertising" Expenses</u>

Staff witness Mr. Kahle's proposed adjustments, to remove what he contended were promotional, goodwill, or institutional advertising expenses from operating expenses, in the gross amounts of $308,000 as to Peoples Gas and $43,000 as to North Shore, are uncontested. Kahle Dir., Staff Ex. 3.0, 10:202 – 11:230, Sched. 3.2 P, p. 1, and Sched. 3.2 N, p. 1; Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:100.

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[11] Staff withdrew their proposed adjustment on this subject. Hathhorn Reb., Staff Ex. 13.0, 6:132 – 7:142.

b. Dues and Memberships Expenses (PGL)

Staff witness Mr. Kahle's proposed adjustment, to remove certain membership dues in the gross amount of $14,000 from Peoples Gas' operating expenses, is uncontested. Kahle Dir., Ex. 3.0, 12:251-263 and Sched. 3.4 P; Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:101.

5. Administrative & General Expenses

a. Civic, Political, and Related Activities Expenses

Staff witness Ms. Hathhorn's proposed adjustments, to remove expenses for civic, political and related activities in the gross amounts of $80,000 as to Peoples Gas and $11,000 as to North Shore from operating expenses, are uncontested. Hathhorn Dir., Staff Ex. 1.0, 12:255 – 13:265 and Scheds. 1.9 P and 1.9 N); Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:92.

b. Employee Recreation Expenses

Staff witness Ms. Hathhorn's proposed adjustments, to remove expenses for employee recreation in the gross amounts of $54,000 as to Peoples Gas and $7,000 as to North Shore from operating expenses, are uncontested. Hathhorn Dir., Staff Ex. 1.0, 18:366-376 and Scheds. 1.14 P and 1.14 N; Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:93.

c. Corporate Rebill of Income Tax Penalties

Staff witness Ms. Hathhorn's proposed adjustments, to remove the rebilling of income tax penalties from Peoples Energy Corporation to the Companies, in the gross amounts of $35,000 as to Peoples Gas and $5,000 as to North Shore, are uncontested. Hathhorn Dir., Staff Ex. 1.0, 17:355 – 18:363 and Scheds. 1.13 P and 1.13 N; Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:97.

d. Lobbying Expenses

Staff witness Mr. Kahle's proposed adjustments, to disallow lobbying expenses from rate base and operating expenses in the gross amounts of $12,000 (capitalized) and $67,000 (operating expenses) as to Peoples Gas and $3,000 (capitalized) and $13,000 (operating expenses) as to North Shore, are uncontested. Kahle Dir., Staff Ex. 3.0, 11:232 – 12:249 and Scheds. 3.3 P and 3.3 N; Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:99.

e. Executive Perquisites Expenses

Staff witness Ms. Pearce's proposed adjustments, removing executive perquisites in the gross amounts of $170,000 as to Peoples Gas and $15,000 as to North Shore from operating expenses, are uncontested. Pearce Dir., Staff Ex. 2.0, 18:454 – 19:474 and Scheds. 2.3 P and 2.3 N; Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:105.

f. Termination Costs (PGL)

Staff witness Ms. Pearce's proposed adjustment, removing a gross amount of $259,000 in termination costs from Peoples Gas' operating expenses, is uncontested. Pearce Dir., Staff Ex. 2.0, 20:492 – 21: 503 and Sched. 2.5 P; Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:106.

g. Salaries and Wages Expenses

Staff witness Ms. Pearce's proposed adjustments, reflecting the Utilities' corrections to errors in their underlying calculations supporting their *pro forma* adjustments for salaries and wage increases, reducing operating expenses by the gross amounts of $124,000 as to Peoples Gas and $25,000 as to North Shore, are uncontested. Pearce Dir., Staff Ex. 2.0, 21:506 – 22:523 and Scheds. 2.6 P and 2.6 N; Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:107.

h. **Medical and Insurance Expenses**

GCI witness Mr. Effron's proposed adjustments to operating expenses, reducing Peoples Gas' and North Shore's medical and insurance expenses by the gross amounts of $866,000 and $83,000, respectively, are uncontested. Effron Dir., GCI Ex. 2.0, 22:495 – 24:529 and Sched. C-2.1; Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:112.

i. **Rate Case Expenses**

Staff witness' Mr. Griffin's revised proposed adjustments to operating expenses, reducing Peoples Gas' and North Shore's rate case expenses as updated in rebuttal testimony by the gross amounts of $680,000 and $690,000, respectively, with all rate case expenses to be amortized over five years (based on the theory that that is a reasonable time to expect the rates set in these proceedings to remain in effect) with no carrying charges, are uncontested. Griffin Reb., Staff Ex. 16.0, 2:23 – 6:109 and Scheds. 16.1 P and 16.1 N; Effron Reb., GCI Ex. 5.0, 8:199 – 9:222; Fiorella Sur., NS-PGL Ex. SF-4.0, 5:97-107 (in rebuttal testimony, the Utilities requested carrying charges if a five year amortization period was used, rather than the three year period they originally proposed, but in surrebuttal testimony, the Utilities withdrew that request).

j. **Franchise Requirements Expenses (NS)**

GCI witness Mr. Effron's recalculated proposed adjustment to North Shore's operating expenses relating to franchise requirements expenses is uncontested. Mr. Effron proposed an adjustment to these expenses in his direct testimony. Effron Dir., GCI Ex. 2.0, 29:652 -31:686. North Shore and Peoples Gas witness Ms. Kallas responded that North Shore was willing to accept the proposal, but only if it were recalculated based on updated fuel prices and fiscal year 2006 volumes, which results in a $584,000 adjustment (gross amount). Kallas Reb., NS-PGL Ex. LK-2.0 REV, 14:294-309; NS-PGL Ex. LK-2.3. Mr. Effron agreed with that recalculated amount. Effron Reb., GCI Ex. 5.0, 11:269 – 12:280. No other witness disagreed. Thus, the recalculated adjustment is uncontested.

k. <u>PEC Officer Costs and Directors Fees</u>

Staff witness Ms. Hathhorn's revised proposed adjustments to operating expenses, removing Peoples Energy Corporation officer costs and directors fees that were allocated to the Utilities, in the gross amounts of $702,000 as to Peoples Gas and $100,000 as to North Shore, are uncontested. Hathhorn Reb., Staff Ex. 13.0, 11:227 – 12:261 and Scheds 13.9 P and 13.9 N; Fiorella Sur., NS-PGL Ex. SF-4.0, 6:126-130.

6. <u>Taxes Other Than Income Taxes (Personal Property Taxes)</u>

Peoples Gas' personal property taxes included in Taxes Other Than Income Taxes were updated to include a gross amount increase of $1,181,000, reflecting a court decision. Fiorella Reb., NS-PGL 2.0, 13:281-290; NS-PGL Ex. SF-2.8 P. No witness contested the update.

7. <u>Income Taxes (Interest Synchronization)</u>

The parties do not dispute that the Interest Synchronization component of income taxes should be recalculated, for purposes of final approved revenue requirement calculations, based on the final approved rate base times the weighted cost of debt. *E.g.*, Hathhorn Dir., Staff Ex. 1.0, 7:133-143 and Scheds. 1.5 P and 1.5 N; Effron Dir., GCI Ex. 2.0, Sched. C-4; Fiorella Reb., NS-PGL Ex. SF-2.0, 4:82-90, 5:94-95.

C. <u>Contested Issues</u>

1. <u>Storage Expenses</u>

a. <u>Crankshaft Repair Expenses (PGL)</u>

The Commission should approve GCI's proposed adjustment relating to Peoples Gas' crankshaft repair expenses. Peoples Gas' test year operating expenses incorporated in its original proposed revenue requirement included $546,000 for repair expenses related to failure of the crankshaft on the Manlove Field compressor. L. Kallas Dir., PGL Ex. LK-1.0, 13:282-288. GCI proposed that, because of the unusual nature of this failure, Peoples Gas should be allowed to recover these expenses, but only on an amortized basis over a four year period, which meant that the test year amount of $546,000 would be reduced by $410,000, i.e., to $136,000, in calculating the revenue requirement. Effron Dir., GCI Ex. 2.0, 32:722 – 33:738 and Sched. C-2 (Peoples Gas). Peoples Gas accepted GCI's proposed adjustment. Fiorella Reb., NS-PGL Ex. 2.0, 4:82-90, 5:111, 12:251-261.

In contrast, Staff proposed to completely deny any recovery of the $546,000, which would mean eliminating that $136,000 in the revenue requirement calculation. Lounsberry Dir., Staff Ex. 11.0, 32:605 – 34:643; Lounsberry Reb., Staff Ex. 23.0, 19:353 – 20:380.

GCI's proposal is a reasonable balance between the fact that Peoples Gas actually incurred these expenses in the test year and the fact that they were unusual. Staff's proposal is less reasonable, because it makes no such balance and instead denies all cost recovery. Moreover, Staff's proposal here is inconsistent with its position regarding collection agency fees, where Staff contends that a level of that expense in the test year that is much lower than the level in prior years should be used in calculating the revenue requirement, as is discussed in Section III(C)(2) of this Initial Brief, *infra*. GCI's proposal, not Staff's, should be adopted.

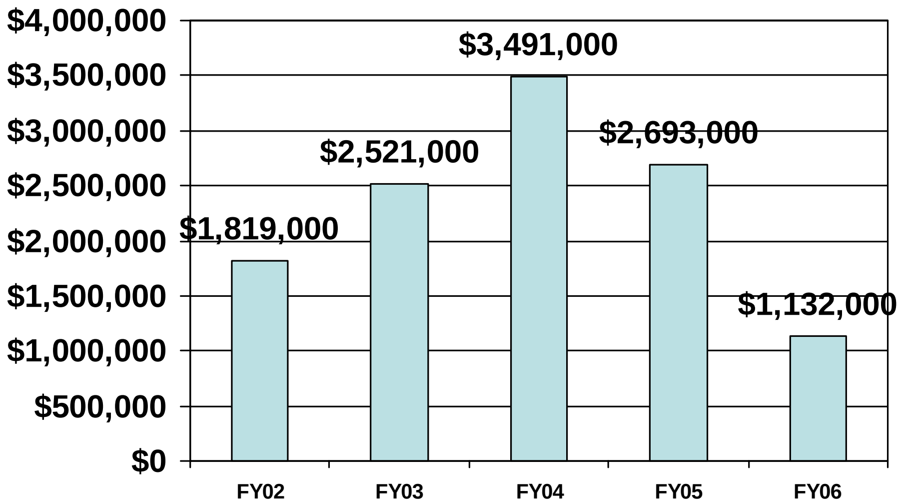
b. <u>Hub Services (PGL)</u> (To be addressed in Section V, below)

2. <u>Customer Accounts Expenses (Collection Agency Fees)</u>

In calculating their revenue requirements, the Utilities appropriately substituted three year averages of the collection agency fees incurred in fiscal years 2003 through 2005 for the level in the test year, fiscal year 2006, because the latter was abnormally low due to the 2006 Gas

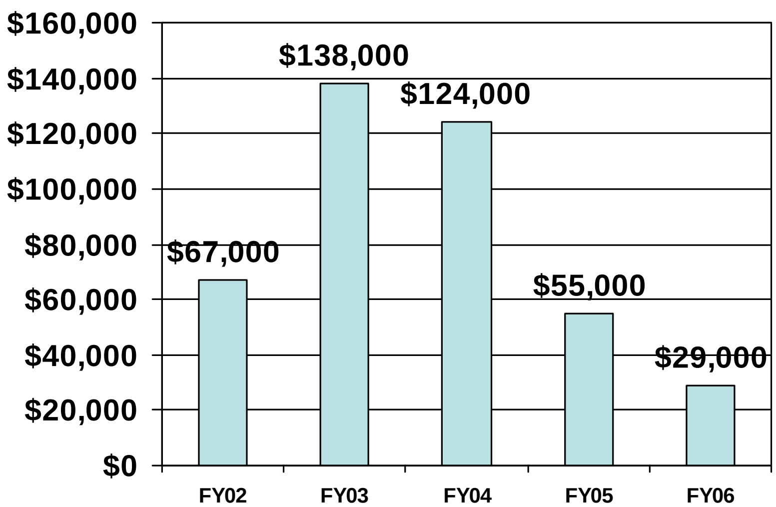
Charge settlement. Fiorella Dir., PGL Ex. SF-1.0, 28:603-607; PGL Ex. SF-1.1, Sched. C-2.19; Fiorella Dir., NS Ex. SF-1.0, 26:572-576; NS Ex. SF-1.1, Sched. C-2.19. The dramatic effect of the settlement on the test year level of the fees is apparent when compared to prior years.

Peoples Gas Collection Agency Fees



Source of data: Hathhorn Dir., Staff Ex. 1.0, Sched. 1.8 P, p. 2.

North Shore Collection Agency Fees



Source of data: Hathhorn Dir., Staff Ex. 1.0, Sched. 1.8 N, p. 2.

Staff's witness nonetheless proposed that the Utilities be required to use the test year level in calculating their revenue requirements, resulting in proposed disallowances in the gross amounts of $1,770,000 and $76,000 as to Peoples Gas and North Shore, respectively. Hathhorn Dir., Staff Ex. 1.0, 8:162 – 12:252, Sched. 1.8P, p. 1, Sched. 1.8N, p. 1. Staff's proposed adjustments, however, are unsound.

The three year average of fiscal years 2003 through 2005 should be used to set the level of collection agency fees included in the revenue requirements. As North Shore and Peoples Gas witness Ms. Kallas stated:

> Collection agencies are used to collect on older bad debt accounts. Therefore, fiscal years 2006 and 2007 amounts are artificially low due to the companies' agreement to not attempt to collect accounts that had been written-off and remained uncollected as of September 30, 2005. Accounts written off subsequent to September 30, 2005, however are not forgiven and have been and will be assigned to collection agencies for collection. This will result in collection agency fees being substantially more than experienced in the test year. A good estimate of the expected level of collection agency fees for the first year that the rates set in this proceeding will be in effect is the fiscal year 2003 through 2005 average used in Mr. Fiorella's proposed adjustment. In other words, the averaging of actual experience not affected by the agreement (i.e., fiscal years 2003 through 2005) is much more indicative of normal activity and cost for this account.

Kallas Reb., NS-PGL Ex. LK-2.0 REV, 5:93-104. Staff's proposed adjustments are unwarranted and should be rejected.

3. Administrative & General Expenses

a. Injuries and Damages Expenses

The Utilities incorporated their respective appropriate levels of injuries and damages expenses in calculating their revenue requirements. Peoples Gas appropriately used the test year level, adjusted for a highly unusual credit recorded in fiscal year 2006 relating to a major claim that occurred in fiscal year 2002. Fiorella Dir., PGL Ex. SF-1.0, 19:420 – 21:466, 23:496, 31:673-679; PGL Ex. SF-1.1, Sched. C-1, lines 13-14, Sched. C-2, line 30, and Sched. C-2.30. North Shore appropriately used its unadjusted test year level. Fiorella Dir., NS Ex. SF-1.0, 18:393 – 20:439; NS Ex. SF-1.1, Sched. C-1, lines 13-14; Sched. C-2.

Staff's proposed adjustments to injuries and damages expenses are unwarranted and arbitrary, and should be rejected. Staff's witness proposes to set the levels for these expenses using the following methodology:

(1) calculate the five year average of the accruals for these expenses over the period of fiscal years 2002 through 2006,

(2) calculate the five year average of actual payouts over that period,

(3) divide the latter by the former to develop a percentage, and

(4) multiply that percentage times the fiscal year 2006 accrual to obtain the allowed level to be included in the revenue requirement.

See Griffin Reb., Staff Ex. 16.0, Scheds. 16.2 P and 16.2 N. Staff's witness, in his direct testimony, contended that the levels of injuries and damages expenses fluctuate and therefore should be normalized; proposed the above methodology to set the levels; and cited *In re Central Illinois Light. Co.*, et al., ICC Docket Nos. 06-0070, 06-0071, 06-0072 Cons., pp. 48-49 (Order Nov. 21, 2006). Griffin Dir., Staff Ex. 4.0, 8:136 – 9:159. He offered no reason for selecting a five year normalization methodology, as opposed to some other period, apart from that citation.

North Shore and Peoples Gas witness Ms. Kallas, in her rebuttal testimony, noted data errors made by Staff's witness, and pointed out that normalization was unwarranted here. Kallas Reb., NS-PGL Ex. LK-2.0 REV, 9:198 – 11:226.

Staff's witness, in his rebuttal testimony, corrected his data errors, but expressed the view that the differences between his corrected averages and the Utilities' proposed levels, 14% as to Peoples Gas and 22% as to North Shore, were significant enough that his proposed adjustments should be made. Griffin Reb. Staff Ex. 16.0, 7:128-139. He still did not provide any specific support for his choice of the five year period that yielded those percentages.

Ms. Kallas, in her surrebuttal testimony again disagreed that normalization is warranted, pointed out that Staff's witness still had not provided any specific support for his choice of a five year period, and further pointed out that using four and three year periods would not support Staff's proposed adjustments, and, in fact, a four year average would increase the levels of injuries and damages expenses included in the revenue requirements of both of the Utilities:

> Considering the relative closeness of this expense in the test year to the five year period chosen by Mr. Griffin, there is no good reason this expense should be normalized. Moreover, Mr. Griffin does not explain why he chose to use five years. If four years were used for Peoples Gas (fiscal years 2003 through 2006), it would indicate a higher "normalized" expense than actual fiscal year 2006. If a three year period is chosen for Peoples Gas, the "normalized" expense would almost equal the fiscal year 2006 accrual. The results are even more significant for North Shore where excluding fiscal 2002 in the calculation results in cash payments much higher than accruals.

L. Kallas Sur., NS-PGL Ex. LMK-3.0, 5:93-100.

In *In re Central Illinois Light. Co.*, et al., ICC Docket Nos. 06-0070, 06-0071, 06-0072 Cons., pp. 48-49 (Order Nov. 21, 2006), the case cited by Staff's witness, Staff looked at five years of data, but then discarded, in each instance, data from one year that Staff considered unrepresentative, resulting in Staff's use of four-year averages. Here, the fiscal year 2002 data that Staff uses is very different from the data for the other four years (*see* Griffin Reb., Staff Ex. 16.0, Scheds. 16.2 P and 16.2 N), and, as indicated above, excluding that one year would result in increases, not decreases, in the levels of injuries and damages expenses included in the revenue requirements of both of the Utilities. The Commission should not adopt Staff's proposed adjustments. There is no significant reason to normalize these expenses, and it is evident that the arbitrary choice of a five year period is not warranted.

b. Incentive Compensation Expenses

(i) The Utilities Are Entitled to Recover All of the Challenged Incentive Compensation Costs

Peoples Gas and North Shore seek to recover $5,376,000 and $576,000, respectively, of incentive compensation program costs (gross amounts, including capitalized expense amounts and operating expenses (including associated payroll taxes in Taxes Other Than Income Taxes)) in their revenue requirements. Pearce Dir., Staff Ex. 2.0, Scheds. 2.2P and 2.2N. These costs are prudent and reasonable in amount, and the Utilities should be allowed to recover them. Staff and GCI propose to disallow all of these costs, but their proposals are erroneous and unreasonable, and should be rejected. In the alternative, at a minimum, certain costs should be allowed, as discussed further below, that is (1) Peoples Gas and North Shore should be allowed to recover $1,009,240 and $94,204, respectively, under the Team Incentive Award ("TIA)" plan; and (2) $625,791 and $53,107 under the Individual Performance Bonus ("IPB") plan, respectively.

Like other large companies, Peoples Gas and North Shore include incentive compensation as part of their overall employee compensation packages. James Hoover, Director of Compensation for Integrys, testified that the Utilities must offer incentive compensation in order to provide the competitive compensation package necessary to attract and to retain high-quality employees: "The Utilities and other large businesses seek to design employee compensation in order to attract and retain a sufficient, qualified, and motivated work force. Incentive compensation programs are a common method to help achieve those objectives." Hoover Reb., NS-PGL Ex. JCH-1.0, 3:55-57. No witness challenged this testimony.

Incentive compensation plainly qualifies as a prudent expense. As Mr. Hoover explained, "[t]he Utilities compete in the labor market with other utilities and other businesses that offer incentive compensation.... [T]he programs are the product of careful decisions about what types and levels of incentive compensation are needed in order to attract and retain a sufficient, qualified, and motivated work force...." Hoover Reb., NS-PGL Ex. JCH-1.0, 3:57-59, 8:150-153. Furthermore, incentive compensation for that reason benefits a utility's customers: "A utility's attracting and retaining a sufficient, qualified, and motivated work force benefits its customers, by making sure there are enough employees to perform needed work, by maintaining and improving the productivity and quality of work, and by reducing the expenses associated with recruiting and training new employees." *Id*. at 3:63-4:66. Again, no witness challenged this testimony, although two witnesses did claim that such customer benefits should be disregarded under their understandings of the Commission's past approaches to the subject of incentive compensation, as discussed further below.

The record also contains further evidence of more specific, tangible customer benefits. For instance, Mr. Hoover and Mr. Volante, until recently Manager of Compensation for Peoples Energy Corporation, testified in their Surrebuttal Testimony that the incentive compensation programs were a contributing factor in Peoples Gas and North Shore's reduction of O&M expenses below target levels. Hoover / Volante Sur., NS-PGL Ex. JCH/FLV-2.0, 6:112-117. The Commission has recognized that incentive compensation programs that reward employees for lowering operating costs benefit customers. *See In re Commonwealth Edison Co.*, ICC Docket No. 01-0423, at 129 (Order, March 28, 2003); *In re Consumers Illinois Water Co.*, ICC Docket No. 03-0403, at 14-15 (Order, April 13, 2004); *In re Northern Illinois Gas Co.*, ICC Docket No. 95-0219, at 27 (Order, April 3, 1996). While Staff's witness suggests that controlling and reducing costs do not count as benefiting customers, that is illogical and is inconsistent with Commission orders she herself relies upon. Hoover / Volante Sur., NS-PGL Ex. JCH/FLV-2.0, 4:72 – 5:92. Staff's claims about what does not count as benefiting customers are inconsistent and unreasonable. *Id.* Ms. Pearce admits that measures tied to customer satisfaction (discussed below) directly benefit ratepayers. Pearce Dir., Staff Ex. 2.0, 19:430-432.

No witness has challenged Peoples Gas' and North Shore's total compensation to employees, or, in particular, the incentive compensation portions, as imprudent or excessive. No witness testified that their incentive compensation programs and payouts thereunder are not prudent and reasonable from the perspective of managing their human resources. Hoover Reb., NS-PGL Ex. JCH 1.0, 4:67-70. Indeed, it is clear that under the Staff and GCI positions, the amounts of incentive compensation that they challenge would not be challenged if the Utilities had paid the exact same amounts of total compensation but had made the incentive compensation amounts part of base pay. *See, e.g.*, Effron Tr., 1196:3 – 1200:15. In light of this testimony, the Utilities' challenged incentive compensation costs merit full recovery through rates.

Notwithstanding these facts, Staff witness Bonita Pearce and GCI witness David Effron propose to deny Peoples Gas and North Shore recovery of the incentive compensation portions of their total compensation expense. *E.g.*, Pearce Dir., Staff Ex. 2.0, 6:134-18:451; Effron Dir., GCI Ex. 2.0, 25:545 - 26-568. They do so without disputing that the Utilities' total compensation and the incentive compensation portions are prudent or reasonable in amount. During cross-examination, Mr. Effron acknowledged that his testimony did not even address whether the Utilities' incentive compensation programs are prudent. Effron Tr. at 1196:15-21. (Ms. Pearce's testimony also did not do so.) He further indicated that under his approach (which is the same as Staff's), it would not matter whether the Utilities' incentive compensation program helped to attract and retain the most qualified employees. Effron Tr. at 1203:7-21. Staff's witness made a similar admission:

> [One of the reasons] given by Mr. Hoover in support of incentive compensation expense recovery in the 2006 test year is his belief that such plans "are prudently

> and reasonably designed in order to attract and retain a sufficient, qualified and motivated work force." This assertion made by Mr. Hoover, even if correct, does not detract from the basis of my adjustment.

Pearce Reb., Staff Ex. 14.0, 6:125-129. The proposed disallowances thus contravene the established principle that rates "must allow the utility to recover costs prudently and reasonably incurred." *Citizens Utility Board v. Illinois Commerce Comm'n*, 166 Ill. 2d 111, 121 (1995).

The remaining arguments of Staff and GCI regarding incentive compensation costs were speculative and arbitrary, do not warrant their proposed disallowances, and were fully refuted by the Utilities. *See* Hoover Reb., NS-PGL Ex. JCH-1.0, 2:37 – 12:227; Hoover / Volante Sur., NS-PGL Ex. JCH/FLV-2.0, 3:59 – 11:237; NS-PGL Exs. JCH/FLV-2.1, JCH/FLV-2.2.

Peoples Gas and North Shore seek to recover costs associated with several specific programs within their incentive compensation plans. Those programs include: (1) the Team Incentive Award plan; (2) the Individual Performance Bonus plan; (3) the Short-term Incentive Compensation ("STIC") plan; (4) officers' incentive compensation and bonuses charged by Peoples Energy Corporation to Peoples Gas and North Shore; and (5) long-term incentives, such as restricted stock and performance shares, covered by the 2004 incentive compensation plan. The evidence regarding those plans shows that the proposed disallowances should be rejected.

(ii) <u>The TIA Plan</u>

The 2006 Team Incentive Award plan applied to non-officer, non-union employees. Hoover Reb., NS-PGL Ex. JCH-1.0, 4:74-75. The performance measures under the TIA plan were 55% "financial" and 45% "operational". *Id*. at 4:76 – 5:80. The "operational" performance measures consisted of a 25% weighting for controlling O&M expenses and a 20% weighting for customer satisfaction criteria (10% based on the number of calls to the Utilities' call centers and 10% based on the ranking of the Utilities' Gas Charges compared with those of six other Illinois utilities.) *Id*. at 4:80 – 5:86. The Utilities demonstrated, in detail, that Staff's attempts to deny that 45% of the measures were operational are not correct, and Staff actually admitted that the Call Center metric benefits customers. Hoover / Volante Sur., NS-PGL Ex. JCH/FLV-2.0, 5:105 – 7:146. Accordingly, while complete recovery of the entire $1,642,847 paid out, $1,502,584 by Peoples Gas and $140,253 by North Shore ($1,607,568 had been accrued, $1,465,444 by Peoples Gas and $142,124 by North Shore), under the TIA plan (Kallas Reb., NS-PGL Ex. LK-2.0, 9:181-185 (dollar amounts)) is appropriate, at a minimum, Peoples Gas should recover the $1,009,240, and North Shore should recover the $94,024, that they paid out under the operational measures. Hoover / Volante Sur., NS-PGL Ex. JCH/FLV-2.0, 7:147-149.

(iii) <u>The IPB Plan</u>

The 2006 Individual Performance Bonus plan also applied to non-officer, non-union employees. Hoover Reb., NS-PGL Ex. JCH-1.0, 5:93-94. The performance measures under the IPB plan were not "financial", rather each division's senior management, with input from their managing staff, was responsible for calculating and awarding the IPB to their own employees, and, as the name of the plan indicates, the awards were based on individual performance. *Id*. at 5:95-103. Staff's unsupported speculation that the pool for this plan might somehow be "financial" was incorrect. Hoover / Volante Sur., NS-PGL Ex. JCH/FLV-2.0, 9:183-188. The plan benefited customers by encouraging outstanding individual work performance. *Id*. at 9:190-191; NS-PGL Ex. JCH/FLV 2.2. Staff's objection that the Utilities did not establish specific dollar savings and other tangible benefits is not reasonable given that the pool and the awards are not tied to financial performance and the IPB awards went to 426 different employees in an average amount of $2,884.53. Hoover / Volante Sur., NS-PGL Ex. JCH/FLV-2.0, 9:197 – 10:205. Accordingly, complete recovery of the entire $678,898 paid out, $625,791 by Peoples Gas and $53,107 by North Shore ($496,910 had been accrued, $464,408 by Peoples Gas and

$32,502 by North Shore), under the IPB plan (Kallas Reb., NS-PGL Ex. LK-2.0, 9:186-189 (dollar amounts)) is appropriate.

(iv) <u>The STIC Plan</u>

The 2006 STIC plan applied to senior management of Peoples Gas. Hoover Reb., NS-PGL Ex. JCH-1.0, 6:107-108. The performance measures under the STIC plan were the same as under the TIA plan, discussed above. *Id*. at 6:111-113. There were no payouts as to fiscal year 2006, but that was for unusual reasons that are not expected to reoccur. *Id.* at 6:108-110. Accordingly, complete recovery of the entire $457,000 that was accrued, or, at a minimum, of the $306,953 that was accrued as to the operational measures, under the STIC plan (Kallas Reb., NS-PGL Ex. LK-2.0, 9:190-194 (dollar amounts)), is appropriate.

(v) <u>The Affiliate Charges</u>

The Peoples Energy Corporation charges for officers incentive compensation and bonuses to Peoples Gas and North Shore were generally based 37.5% on operational measures. Hoover Reb., NS-PGL EX. JCH-1.0, 6:114-123. Accordingly, the entire $744,812 charged to Peoples Gas and the entire $165,811 charged to North Shore (Pearce Dir., Staff Ex. 2.0, Sched. 2.2P, p. 2, lines 12-13, and Sched. 2.2N, p. 2, line 12 (dollar amounts)) should be recovered or, at a minimum, 37.5% thereof.

(vi) <u>Restricted Stock and Performance Shares</u>

The restricted stock program was based on providing a competitive compensation package, not “financial” measures, while the performance shares program was based on “financial” measures. Hoover Reb., NS-PGL Ex. JCH-1.0, 7:131-142. Accordingly, the entire $1,756,000 accrued (Peoples Gas only) (Pearce Dir., Staff Ex. 2.0, Sched. 2.2P, p. 2, lines 4-5 (dollar amount) should be recovered or, at a minimum, the amount of $1,529,000 as to the restricted stock program (*id*. at line 4 (dollar amount)) should be allowed.

In sum, the evidentiary record demonstrates that incentive compensation benefits customers through: increased customer satisfaction; improved service reliability; more efficient, lower cost operations that lead to lower rates over time when compared to less efficient operations; improved employee performance; enhanced ability to attract and to retain high-quality employees; and better employee productivity. These numerous benefits satisfy any Commission requirement that incentive compensation not only be prudent and reasonable but benefit customers. By claiming that more is required in the way of specific dollar savings, Staff and GCI advance an unsupportable and inconsistent interpretation of the Commission's past tests. In any event, their proposals would wrongly deny Peoples Gas and North Shore their right to recover all prudent and reasonable expenses. *See Citizens 1995*, 166 Ill. 2d at 121.

The Commission has approved recovery of incentive compensation expenses in various other rate cases, including: *In re Commonwealth Edison Co.*, ICC Docket No. 05-0597, at 97 (Order July 26, 2006)*; In re Consumers Illinois Water Co.*, ICC Docket No. 03-0403, at 14-15 (Order April 13, 2004); *In re Illinois-American Water Co.*, ICC Docket No. 02-0690, at 17-19 (Order August 12, 2003); and *In re Commonwealth Edison Co.*, ICC Docket No. 01-0423, at 109-111 (Interim Order April 1, 2002), and at 120-122 (Order March 28, 2003). The Commission should do so here. In the alternative, the Commission should allow recovery of the specified operational and non-financial expenses discussed above, including, at a minimum: (1) Peoples Gas and North Shore should be allowed to recover $1,009,240 and $94,204, respectively, under the TIA plan; and (2) $625,791 and $53,107 under the IPB plan, respectively.

4. **Invested Capital Taxes**

The Utilities believe that, apart from an entirely speculative objection on the part of GCI, discussed below, there is no dispute that invested capital taxes need to be recalculated based on the final approved rate increases (the increases in base rate revenues) when setting the Utilities' final approved revenue requirements, and that there is no dispute over how to perform those calculations. *E.g.*, Fiorella Reb., NS-PGL Ex. SF-2.0, 15:318-326; NS-PGL Exs. SF-2.13P and 2.13N; Staff Cross Fiorella Exs. 1 and 2.

GCI witness Mr. Effron proposed, on two grounds, to disallow the Utilities' *pro forma* adjustments reflecting the impacts on invested capital taxes of their proposed rate increases. His first ground, essentially, is the point that invested capital taxes need to be recalculated based on the final approved rate increases. *See* Effron Dir., GCI Ex. 2.0, 34:770 – 35:774. As noted above, the Utilities agree that there needs to be such a recalculation. That does not warrant simply rejecting the *pro forma* adjustments, however, which would assume that there will be no approved rate increases at all, a result that is inconsistent with the parties' positions. Staff agrees with the Utilities' position. *See, e.g.*, Hathhorn Dir., Staff Ex. 1.0, 14:288 – 15:296.

Mr. Effron's second ground is his raw speculation that "it is entirely possible that an increase to operating income would lead to an increase in dividends. To the extent that any additional earnings are paid out in dividends, there will be no increase to retained earnings as a result of the increase in operating income." Effron Dir., GCI Ex. 2.0, 35:777-780. Mr. Effron cites no factual basis for his speculation. There is none. Mr. Effron's proposal to deny recovery of invested capital taxes on the basis of such speculation is improper. *E.g., Ameropan Oil Corp. v. ICC*, 298 Ill. App. 3d 341, 348 (1st Dist. 1998) ("speculation has no place in the ICC's decision or in our review of it."); *Allied Delivery System. Inc. v. Illinois Commerce Comm'n*, 93

Ill. App. 3d 656, 667 (1st Dist. 1981) ("The speculation indulged in by the Commission is clearly an unsatisfactory and unacceptable basis for its decision."); *In re Commonwealth Edison Co.*, ICC Docket No. 99-0117 (Order, August 25, 1999), at p. 105 ("we will not make an adjustment that is speculative…."). The Commission should calculate the final level of invested capital taxes, in the manner shown by the Utilities, based on the final approved rate increases.

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

Peoples Gas and North Shore understand this subject to be a non-substantive operating income Schedule presentation issue raised by Staff. *See* Hathhorn Dir., Staff Ex. 1.0, 8:154-159. The Utilities, subject to that understanding, do not object, at the concept level, to the preparation of operating income Schedules that correctly identify which of their revenues and expenses are associated with their base rate charges versus non-base rate items.

D. Derivative Adjustments from Uncontested and Contested Issues

Various of Staff's and GCI's contested proposed rate base and operating expenses adjustments, when their full impacts are calculated, have derivative impacts on depreciation expenses, taxes other than income taxes, and/or income taxes, as shown in their respective Schedules, but no party has proposed any independent adjustments to these items. Hathhorn Reb., Staff Ex. 13.0, Sched. 13.2 P, lines 14, 17, and 20-21, and Sched. 13.2 N, lines 14, 17, and 20-21; GCI Ex. 5.1, Scheds. C Rev., C-2 Rev., C-3 Rev., C-4 Rev., C-5 Rev.; GCI Ex. 5.2, Scheds. C Rev., C-2 Rev., C-3, C-4 Rev., C-5 Rev. Accordingly, the Commission's final Order, as to the foregoing items, need only make derivative calculations, if any, depending on whether it approves any of Staff's and GCIs' contested proposed adjustments.

IV. RATE OF RETURN

Overview

The Parties' Positions

Peoples Gas proposes an ROR of 8.24% on its rate base. This rate is based on a capital structure containing 56% common equity at a cost of 11.06% and 44% long-term debt at a cost of 4.67%. NS-PGL Ex. BAJ-2.1P. North Shore proposes an ROR of 8.56% on its rate base. This rate is based on a capital structure containing 56% common equity at a cost of 11.06% and 44% long-term debt at a cost of 5.39%. NS-PGL Ex. BAJ-2.1N.

There is agreement (or at least lack of disagreement) among the parties on the Utilities' proposed capital structures and their costs of long-term debt. No party argues that the Utilities' capital structure should include short-term debt. The sole area of disagreement is over the Utilities' authorized ROEs.

In this regard, the parties are very far apart. The Utilities propose equal rates of return at 11.06%. This rate is justified by the financial market models traditionally relied on by the Commission, and is consistent with other indicators of investor expectations, such as the rates of return recently authorized for other natural gas utilities around the country, including the 10.51% this Commission authorized Nicor Gas Company in late 2005. *In re Northern Illinois Gas Co.*, ICC Docket No. 04-0779, pp. 84-88 (Order Sept. 20, 2005) ("*Nicor*").

By contrast, Staff and CUB-City[12] propose equity returns at levels far below what any sophisticated investor would expect. Indeed, they are lower than this Commission has set for any natural gas utility for at least 30 years. Moul Sur., NS-PGL Ex. PRM-3.0, 12:255-260 (citing ICC Financial Analysis Division's *Rate Case Histories* (January 2005 Edition) on the

[12] No other intervenor addressed the Utilities' cost of capital in testimony.

Commission's web site). Staff proposes a rate of return for Peoples Gas of 9.70%, which is 136 basis points below the Utilities' request, and 9.50% for North Shore, or 156 basis points below the Utilities' request. Kight-Garlisch Dir., ICC Staff Ex. 6.0, 16:295; Kight-Garlisch Reb., ICC Staff Ex. 18.0, 2:30. CUB-City propose a rate for both Utilities of 8.11% if the Utilities' proposed decoupling and uncollectibles riders are not approved, and rates below 7.5% if the riders are approved. Thomas Dir., CUB-City Ex. 1.0, 9:186-187, 9:191-195.

Summary of the Utilities' Arguments on Return on Equity

The Utilities' cost of equity expert, Mr. Paul Moul, recommends an 11.06% rate of return for each Utility. This rate is the average of the results generated by Mr. Moul's financial market models, and is verified by his comparison to other rates of return recently authorized for natural gas utilities by this and other state commissions. This rate is also conservative in light of the recent volatility in the stock market and rising interest rates during this proceeding.

The positions taken by the Staff and CUB-City cost of equity witnesses are marked by an overly rigid adherence to the results of their financial market models. When faced with demonstrably unrealistic results, Ms. Sheena Kight-Garlisch and Mr. Christopher Thomas do not appear to have stopped to reconsider whether their results met the Commission's cost of equity standards.

This Commission has long recognized that "cost of common equity measurement techniques necessarily employ proxies for investor expectations [and] judgment is necessary to evaluate the results of such analyses. The rate of return analyst should attempt to replicate the thinking of investors, in developing their expectations regarding the growth in dividends." *Nicor*, at pp. 86-87. "In determining what the cost of equity is for a utility, the Commission must base its decision on sound financial principles that are used by sophisticated investors. When determining whether or not to invest in the stock of a particular utility, the sophisticated investor is, in effect, setting the real cost of capital for that utility. The Commission, in authorizing a rate of return, makes an estimate of what the investor is demanding. It is the Commission that reacts to the investor and not vice versa." *In re Illinois Bell Tel. Co.*, ICC Docket No. 92-0448, 93-0239 (Cons.), p. 103 (Order Oct. 11, 1994) (emphasis added).

The Commission has also held that "a thorough cost of common equity analysis requires both the application of financial models and the analyst's informed judgment. A cost of common equity recommendation based solely on judgment is inappropriate. However, because cost of common equity measurement techniques necessarily employ proxies for investor expectations, judgment is necessary to evaluate the results of such analyses." *In re Aqua Illinois, Inc.*, ICC Docket Nos. 05-0071, 05-0072 (Cons.), pp. 52-53 (Order Nov. 8, 2005). *See also In re Central Ill. Pub. Serv. Co.*, ICC Docket Nos. 02-0798, 03-0008, 03-0009 (Cons.), pp. 83-90 (Order Oct. 22, 2003). In this regard, "the analyst's informed judgment" must be informed by the other types of information upon which sophisticated investors, advisors, and analysts routinely rely, including recent regulatory decisions and market trends.

Mr. Moul offered a practical framework in which to implement the Commission's cost of equity standards. Mr. Moul suggests that valid market model results be used to establish the range of potentially reasonable returns, and other relevant information such as recent results from other rate cases be used to pinpoint the utility's rate of return within that range. *See* Moul Tr. 1043:2-14, 1051:3 - 1052:10, 1079:15 - 1081:3.

Following this approach, Mr. Moul employed three financial models, which produced a range of results from 9.72% to 12.04%, with an average of 11.06%. Moul Dir., PGL Ex. PRM-1.0, 3:59 - 4:72. During this proceeding, Mr. Moul reviewed his recommendation and those of the Staff and CUB-City cost of equity witnesses in light of: (1) the acknowledged limitations to the market models to measure the investor's required return, (2) the rates of return recently awarded other natural gas utilities in Illinois and other states, and (3) the extreme volatility in the equity markets and rising interest rates since this rate case was filed. Based on this information, he reasonably concluded that investors are currently expecting authorized rates of return on equity for natural gas utilities in the mid-10% to 11% range. While his cost of equity recommendation is at the high end of that range, Mr. Moul did not adjust his analysis to account for the increased stock market volatility and interest rates during the course of the proceeding. Therefore, his recommendation is a conservative one. By contrast, the recommendations of Ms. Kight-Garlisch and Mr. Thomas are significantly below the range. Neither of their witnesses explained how their sub-10% positions "replicate the thinking of investors" in light of Mr. Moul's unchallenged evidence of actual investor expectations.

The Utilities want it clearly understood that they are not asking for authorized rates of return to be set "based on" information outside of the market model results, including returns granted other gas utilities and recent developments in the financial markets. By the same token, the Utilities seek a determination by the Commission that this information is not "useless," as Staff asserts. Kight-Garlisch Reb., Staff Ex. 18.0, 14:278-15:296. Rather, objective and widely available information available to and used by investors, analysts, and advisors should be taken into account in setting a utility's equity cost within the range of realistic results from valid applications of the market models.

<u>Governing Legal Standards</u>

The legal standards governing a public utility's entitlement to a fair and reasonable return on its investment are well established and familiar. The classic and still-current formulations are those of the United States Supreme Court in the *Bluefield* and *Hope* cases. A public utility has a constitutional right to a return that is "reasonably sufficient to assure confidence in the financial soundness of the utility and [is] adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." *Bluefield Waterworks & Imp. Co. v. Public Service Comm'n,* 262 U.S. 679, 693 (1923). The authorized return on equity "should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

Illinois law is consistent. This Commission "is charged by the legislature with setting rates which are '*just and reasonable'* not only to the ratepayers but to the utility and its stockholders." *Business and Prof'l People for the Pub. Interest v. ICC*, 146 Ill. 2d 175, 209 (1991) (citing 220 ILCS 5/9-201); *see also* 220 ILCS 5/9-101. This Commission "fully embraces the principles set forth" in the *Bluefield* and *Hope* cases. *In re Consumers Ill. Water Co.*, ICC Docket No. 03-0403, p. 41 (Order April 13, 2004).

As one scholar has summarized the law of the land,

> At a minimum, a public utility must be afforded the opportunity not only of assuring its financial integrity so that it can maintain its credit standing and attract additional capital as needed, but also of achieving earnings comparable to those of other companies having corresponding risks. Further, regulation may use the rate of return as an incentive by awarding returns that are higher than the minimum to those utilities with relatively greater efficiency. But in determining a rate, a commission may not set it so high as to exploit consumers. The concept of a fair rate of return, therefore, represents a range or a zone or reasonableness.

Charles F. Phillips, Jr., THE REGULATION OF PUBLIC UTILITIES 375 (Public Utility Reports 1993).

A. **Capital Structure (Uncontested)**

Each Utility proposes a capital structure consisting of 56% common equity and 44% long-term debt. Johnson Dir., PGL Ex. BAJ-1.0, 5:79-80.[13] The proposed capital structures will be sufficient to provide the Utilities with financial strength and ready access to the capital markets at reasonable cost, and will support the Utilities' relatively strong credit ratings on their debt. *Id.*, 5:93-6:109. The proposed capital structures are consistent with the actual capital structures the Utilities have historically maintained, and they will manage their capital structures to remain consistent with the structures authorized for ratemaking purposes. *Id.*, 6:110-7:142. The proposed capital structures are also consistent with the structures recently approved by the Commission for other natural gas utilities, and compare favorably with the sample of comparative gas utilities used by the cost of equity expert witnesses. *Id.*, 7:143-8:157. No short-term debt is included in the proposed capital structures, because the Utilities use such debt only to finance seasonal cash needs and not as a permanent source of financing rate base investments. *Id.*, 8:158-9:170. *See Nicor*, at 69-72; 83 Ill. Adm. Code § 285.4010(a).

Ms. Freetly of Staff agrees that the Utilities' proposed capital structures are reasonable. She found "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." Freetly Dir., Staff Ex. 5.0, 12:213-215. No other party expressed any opposition to the proposed capital structures. CUB-City included them in their calculation of the overall cost of capital (Thomas Dir., CUB-City Ex. 1.0, 69:1704 - 70:1705), and GCI incorporated it without comment into its calculation of the revenue requirements (Effron Dir., GCI Ex. 2.0, 4:70-92). Thus, the proposed capital structures are uncontested.

[13] For ease of reference, we cite to Mr. Johnson's direct for Peoples Gas on points common to both Utilities.

B. Cost of Long-Term Debt (Uncontested)

Staff proposed small downward adjustments to the Utilities' actual costs of long-term debt to reflect the Utilities' stand-alone financial strength. The Utilities' most recent long-term debt issuances reflect credit ratings of "single A" by Standard & Poor's ("S&P") and "double A" by Moody's,[14] and their costs of long-term debt reflect those ratings, Staff argued that S&P's downrating of the Utilities from AA to A in 2002 was due to the increased risk associated with Peoples Energy Corporation's nonregulated business. Kight-Garlisch Dir., Staff Ex. 6.0, 21:396-22:412.[15] In order to reflect a stand-alone S&P credit rating of AA, Staff adjusted the cost of the Utilities' debt issuances since the downgrade to reflect the spread in cost between utility bonds rated AA and A. Freetly Dir., Staff Ex. 5.0, 5:78-6:110. Staff also adjusted the cost of insured tax-exempt bonds issued by Peoples Gas to reflect the difference in the cost of the insurance premium between AA and A ratings. *Id.*, 6:111-8:133.

The Utilities' Treasurer acknowledged "that it is reasonable to adjust the Utilities' cost of long-term debt to reflect their respective stand-alone financial strength, if and to the extent that it differs from the financial strength of [their corporate parent] Integrys Energy Group, Inc." Johnson Reb., NS-PGL Ex. BAJ-2.0, 3:52-54. Illinois law requires as much. 220 ILCS 5/9-230.

The Utilities did not challenge the need for such adjustments in this case, but did propose that the Staff adjustments be reduced to reflect the fact that the Utilities had split ratings by the credit rating agencies at the time of the debt issuances in question. They were rated A by S&P, but remained rated at the Aa level by Moody's. Johnson Reb., NS-PGL Ex. BAJ-2.0, 3:62-65.

[14] The Utilities are currently rated A- by S&P and A1 by Moody's. Johnson Dir., PGL Ex. BAJ-1.0, 5:97-100.

[15] The debt issuances in question all occurred before Peoples Energy Corporation became a wholly owned subsidiary of Integrys, the Utilities' ultimate corporate parent.

In order to reflect the split ratings, the Utilities proposed that only one-half of Staff's adjustments be reflected in the Utilities' long-term debt costs. *Id.*, 4:67-84.

Staff agreed that the Utilities' split ratings should be reflected in their adjusted long-term debt cost, but believed that the one-notch downgrade of the Utilities by Moody's in 2002 (from "Aa2" to "Aa3") should be reflected and therefore 2/3 of the original adjustment should be used. Freetly Reb., Staff Ex. 17.0, 3:49 - 5:85. However, because Staff's and the Utilities' approaches resulted in the same weighted debt costs for the Utilities, Staff accepted the Utilities' proposed adjustments for the purposes of this case. *Id.*, 5:94-6:102.

The Utilities and Staff acknowledge that their respective adjustments and the differences between them here are relatively small as they relate to the Utilities' overall cost of capital. Nonetheless, the Utilities agree with Staff that Illinois law is strict in this regard. *Illinois Bell Tel. Co. v. ICC*, 283 Ill. App. 3d 188, 669 N.E.2d 919, 933 (2d Dist. 1996) ("We hold that if a utility's exposure to risk is one iota greater, or it pays one dollar more for capital because of its affiliation with an unregulated or nonutility company, the Commission must take steps to ensure that such increases do not enter in its ROR calculation."). Such strictness requires precision, and, therefore, it is appropriate and reasonable to adjust of the Utilities' long-term debt costs to reflect their split credit ratings. Freetly Dir., Staff Ex. 5.0, 6 n.4; Johnson Reb., NS-PGL Ex. BAJ-2.0, 3:52-66. No other party expressed a view on the Utilities' long-term debt costs. Thus, long-term debt costs for North Shore of 5.39% and for Peoples Gas of 4.67% are uncontested. NS-PGL Exs. BAJ-2.1N and 2.1P; Freetly Reb., Staff Ex. 17.0, Scheds. 17.2N and 17.2P.

C. Cost of Common Equity

1. Peoples Gas and 2. North Shore (Combined Discussion)

Mr. Moul, the Utilities' cost of equity expert in this case, is an independent financial and regulatory consultant with over 30 years' experience in the field. PGL Ex. PRM-1.1.[16] He presented three "market" measures of the Utilities' cost of equity using the familiar Discounted Cash Flow model ("DCF"), Capital Asset Pricing Model ("CAPM") and Risk Premium model. Because the Utilities' stock is not publicly traded, the models must be applied to a proxy group of publicly traded natural gas utilities with risk profiles similar to the Utilities. Moul Dir., PGL Ex. PRM-1.0 REV, 3:47-50.

Mr. Moul employed three market models because no one model reliably provides consistently accurate results. Each of them "contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal." Moul Dir., PGL Ex. PRM-1.0 REV, 14:308-311. Mr. Thomas acknowledged the existence of such problems. Thomas, Tr. 1113:10-16. Ms. Kight-Garlisch did not address the question directly, but did acknowledge that the rate of return determination requires consideration of not only the DCF and CAPM model results, but also "the analyst's informed judgment." Kight-Garlisch Dir., Staff Ex. 6.0, 15:286.

Staff and CUB-City, the only other parties to address cost of equity, agreed that Mr. Moul's proxy group provided a reasonable basis on which to base the application of the market models. Ms. Kight-Garlisch for Staff testified that "Mr. Moul's sample companies are reasonable operating risk proxies for North Shore and Peoples Gas." Kight-Garlisch Dir., Staff Ex. 6.0, 2:43-44. Mr. Thomas deemed Mr. Moul's proxy group to be within "a range of reasonableness for the data." CUB-City Ex. 1.0, 12:262-264.

[16] For ease of reference, the Utilities cite to Mr. Moul's direct exhibits for Peoples Gas with respect to points in the direct that are common to both Utilities.

I. <u>The DCF Model</u>

The DCF model seeks to explain the value of an asset as the present value of future expected cash flows – for common stocks, the dividend yield plus future price growth – discounted at the appropriate risk-adjusted rate of return. Moul Dir., PGL Ex. PRM-1.0 REV, 15:320-326, PRM-1.13C. Mr. Moul estimated the dividend yield by calculating the six-month average dividend yield of the utility sample, adjusting the average using three generally accepted methods to reflect the investor's <u>expected</u> cash flows, and then averaging the three adjusted values. Moul Dir., PGL Ex. PRM-1.0 REV, 15:327-16:352. In order to determine the investor-expected growth rate, he evaluated a broad array of historical and forecast growth data from well-recognized sources that are publicly available to, and routinely relied upon by, investors and analysts. *Id.*, 21:442-22:472; PGL Exs. PRM-1.6, PRM-1.7. He focused on forecasts of earnings per share growth because empirical evidence supports it and because that is where investors actually place their greatest emphasis. He selected 5.00%, the approximate mid-point of the forecasts. Moul Dir., PGL Ex. PRM-1.0 REV, 23:490-24:526; PGL Ex. PRM-1.13C, 8:251 – 12:342. He applied a financial leverage adjustment to his DCF result because DCF results are based on market prices of stock, which imply a capital structure with more equity and less financial risk, but are applied to utility book values, which imply a capital structure with less equity and more financial risk. Moul Dir., PGL Ex. PRM-1.0 REV, 25:539 - 28:616. With these inputs, his DCF analysis resulted in an equity cost of 9.53%. *Id.,* 29:633.

Mr. Moul cautioned the Commission against over-reliance on the DCF model due to its inherent limitations. Because the model is based on earnings growth, it will underestimate investor required returns when stock price growth exceeds earnings per share growth. PGL Ex. PRM-1.13B, 1:58-69. Moreover, in the absence of a financial leverage adjustment, the DCF model can underestimate investor required returns when stock prices diverge significantly from book value, as they typically do. PGL Ex. PRM-1.13C, 4:155-6:195.

Ms. Kight-Garlisch (8.23%) and Mr. Thomas (8.11%) derived much lower DCF results than Mr. Moul. Kight-Garlisch Dir., Staff Ex. 6.0, 7:132 & Sched. 6.5; CUB-City Ex. 1.0, 39:965-966. They challenged Mr. Moul's DCF analysis on a number of fronts, each of which instead demonstrate the flaws in the Staff and CUB-City models.

A. <u>Use of Historical Data</u>

Ms. Kight-Garlisch criticizes Mr. Moul for using "historical data to estimate the growth rate and dividend yield in his DCF analysis." Kight-Garlisch Dir., Staff Ex. 6.0, 28:526-527. Her criticism is simply the truism that, by definition, historical data "cannot reflect the most current information available to the market." *Id.*, 29:535-536. Instead, she used the stock prices for the utility sample on a single day to determine the dividend yield input to her DCF model. Her reasoning is that "[s]ince stock prices reflect all current information, only the most recent stock price can reflect the most recently available information." *Id.*, 29:533-535. Ms. Kight-Garlisch's criticism is misplaced, for at least six reasons.

First, she mischaracterizes Mr. Moul's use of historical data in determining the dividend yield and growth inputs. Mr. Moul's DCF dividend yield was not based on historical yields. Rather, he began with the six-month average yield of the utility sample and adjusted it using "generally accepted" methodologies in order "to reflect the <u>prospective</u> nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized." Moul Dir., PGL Ex. PRM-1.0, 16:347-352 (emphasis added); *see also* PRM-1.13C, 6:214-9:250. Ms. Kight-Garlisch did not challenge any of these methodologies. Moreover, although Mr. Moul reviewed historical data in considering the appropriate growth rate, in the end he based his input on a mid-point of earnings per share forecasts. Moul Dir., PGL Ex. PRM-1.0, 17:362-24:526. For these reasons, Staff's criticisms of Mr. Moul's use of historical data to determine the dividend yield and growth inputs to his DCF model are inaccurate and unfair.

Second, Ms. Kight-Garlisch's own justification for using single-day spot stock prices exposes the infirmities of the approach. According to her, "only the most recent stock price can reflect the most recently available information." Kight-Garlisch Dir., Staff Ex. 6.0, 29:534-535. She asserts that "[e]very day new information becomes available and investors rethink their projections of future cash flows, the risk level of the company, and the price of risk." Kight-Garlisch Reb., Staff Ex. 18.0, 10:195-197. In this case, Ms. Kight-Garlisch based her DCF dividend yield on stock prices on April 25, 2007, a date that was over four months old by the time of the hearing and will be about nine months old by the time the ICC issues its final Order. By Ms. Kight-Garlisch's own logic, the stock prices she relied on were "historical" and therefore irrelevant on April 26th and thereafter. Those stock prices by definition cannot have reflected "the most recently available information" at the time of the hearing, and certainly will not do so when the Commission decides these cases.

Third, Ms. Kight-Garlisch's approach assumes a stock market with perfect efficiency to "reflect the most recently available information" on a daily basis. Staff did not introduce any evidence to support that hypothesis, which both Mr. Moul and Mr. Thomas refuted. Mr. Moul testified that "a single day's price can produce an anomalous outcome because it is subject to the vagaries of the market. Indeed, there is evidence to suggest that short-term inefficiencies can exist in stock prices, and those effects are magnified when only a spot price is considered in the DCF return." Moul Reb., NS-PGL Ex. PRM 2.0, 7:153-8:157. Mr. Thomas holds the position that an historical average stock price should be used to balance the view that markets are efficient with the growing body of evidence that suggests that markets may not price securities appropriately in the short term. Thomas, Tr. 1086:14-22. He agrees that investors use a long-term perspective and consider both historical and forecasted stock performance data. Thomas, Tr. 1088:10-16.

It is precisely because of these inefficiencies that analysts commonly use a six-month average dividend yield in the DCF model. The use of such an average provides a more representative estimate, "adds stability to the result and better fits the long-term view of public utility rate setting," and is more appropriate when rates are being set for one or more years in the future. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 8:172-9:180. The use of an historical average ensures "that the prices used in the DCF reflect all available information contained within the stock price." Thomas Reb., CUB-City Ex. 2.1. Rate making is intended to set a return level that is reasonably representative for the period in which the rates will be in effect. "The use of a single-day stock price can accomplish this objective only by pure coincidence." Moul Reb., NS-PGL Ex. PRM-2.0 REV, 8:167-168.

Fourth, the arbitrariness of using single-day spot stock prices to set the rate of return is compounded by the potential for gamesmanship in the single day selected by the analyst. Because of the volatility of stock prices, particularly in recent months, "a longer measurement period provides a more objective basis for a rate of return recommendation." Moul Reb., NS-PGL Ex. PRM-2.0 REV, 8:163-165. To be clear, the Utilities do not assert that Ms. Kight-Garlisch engaged in any such gamesmanship in this case. Moul Sur., NS-PGL Ex. PRM-3.0, 5:98 – 100. Rather, their point is that the method is fraught with excessive subjectivity and is therefore not an appropriate basis for setting utility rates of return.

Fifth, even if one accepts the theoretical validity of using daily spot market data to set utility rates of return, the approach implies a requirement to update the data during the course of a multi-month rate case. Thomas, Tr. 1088:21 - 1090:9. Because Ms. Kight-Garlisch has not updated her analyses, they are necessarily "historical" and, by her own argument, irrelevant. Since April, utility bond yields and stock price volatility have increased significantly. Moul Sur., NSPGL Ex. PRM-3.0, 5:95-97, 9:203-206. These market parameters reflect the extraordinarily high volatility, and increased riskiness, in the financial markets in recent months. *Id.*, 2:26-5:92. If her DCF analysis was updated to reflect spot stock prices on August 28, 2007, her DCF result would be 8.91% instead of 8.23%, a difference of almost 70 basis points. *Id.*, 5:95-97.

Sixth, and perhaps most important, sophisticated investors in the real world do not purchase and sell stocks based exclusively on current prices. Investors avail themselves of the available historical and forecast information, and no thorough analysis of the investor's required return can ignore this information. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 11:230-239; Moul Sur., NS-PGL Ex. PRM-3.0, 6:118-124.

The Commission has long expressed the view that the use of spot stock prices is superior to the use of historical average prices in the DCF model. *E.g., In re Consumers Ill. Water Co.*, ICC Docket No. 03-0403, p. 37 (Order April 13, 2004). The Utilities respectfully request the Commission to reconsider its general concerns about the applicability of historical data in the market return models in the light of the record in this case. In particular, the Utilities urge the Commission to consider the following key points: (1) the lack of an empirical foundation for the use of single-day spot data, which assumes a level of market efficiency that does not exist; (2) the arbitrariness of setting returns based on "current" data that are nine months old; (3) what investors do in the real world, which is to evaluate a stock's historical and forecasted performance in relation to its current price; and (4) Mr. Moul's use of historical data in the DCF model was limited to the dividend yield, and he adjusted a six-month historical average using accepted methods to make it forward-looking.

B. Financial Leverage Adjustment

As noted above, the DCF model underestimates investor required returns when a utility's stock prices diverge significantly from its book value. This occurs because the investor required return produced by the DCF model, which is related to the market value of common stock, is applied to the utility's book value capitalization in ratemaking. Moul Dir., PGL Ex. PRM-1.13C, 4:156 - 5:181. When a utility's stock value exceeds its book value, the DCF result must be adjusted to reflect that difference. Moul Dir., PGL Ex. PRM-1.0, 25:539-546.

The Pennsylvania Public Utility Commission has explained that such an adjustment "is necessary to compensate [the utility] for the mismatched application of a market based cost of common equity to a book value common equity ratio. The adjustment is necessary because the DCF method produces the investor required return based on the current market price, not the return on the book value capitalization." *PPL Electric Utilities Corp.,* 99 Pa. P.U.C. 389, 237 P.U.R.4th 419, p. 34 (Order, December 22, 2004). The mismatch is

> between the financial risk on which the DCF return on equity capital is based and the financial risk embodied in rate setting. This results as the capitalization of a utility measured at its market value contains relatively less debt than the capitalization measured at its book value when market price is above value. The capital structure ratios measured at the book value show more financial leverage (debt) and, therefore, higher risk than the capitalization measured at its market value. It is then necessary to adjust the market based DCF results to reflect the higher financial risk of the book value capital structure used for rate setting purposes.

Id. See also PPL Gas Utilities Corp., 255 P.U.R. 4th 209, p. 51 (Order Feb. 7, 2007) (authorizing 70 basis point financial leverage adjustment); Moul Dir., PGL Ex. PRM-1.0, 27:585-598.

The basis for this financial leverage adjustment is the well-known principle established by Professors and Nobel laureates Franco Modigliani and Merton Miller that, "as the borrowing of a firm increases, the required return on stockholders' equity also increases." Moul Dir., PGL Ex. PRM-1.0, 27:603-604. Using formulas developed by Modigliani and Miller, Mr. Moul calculated a "financial leverage" adjustment of 52 basis points to be used in this case. *Id.*, 27:604 - 28:616; PGL Ex. PRM-1.13C, 12:344 - 14:386.

With this backdrop, Ms. Kight-Garlisch's assertion that "[f]inancial theory provides no basis" for Mr. Moul's financial leverage adjustment is flat wrong. Kight-Garlisch Dir., Staff Ex. 6.0, 33:615-617. Indeed, she cites "Nobel Prize winners Modigliani & Miller" and their conclusion "that common equity costs are affected by debt leverage" in justifying her "credit quality risk" adjustment, discussed in Section IV(C)(1 and 2)(IV)(A) of this Initial Brief. Kight-Garlisch Reb., Staff Ex. 18.0, 4:74-75. Ms. Kight-Garlisch cannot have it both ways.

Instead of addressing the merits of Mr. Moul's adjustment, Ms. Kight-Garlisch proposes a "heads I win, tails I win" tautology. According to Ms. Kight-Garlisch, if a utility's stock price is higher than its book value, it can only mean one of two things. Either "(1) the investor-required rate of return has fallen or (2) expectations of future earnings have risen." Kight-Garlisch Reb., Staff Ex. 18.0, 33:626-627. If the investor-required return has fallen, Ms. Kight-Garlisch says the Commission should of course reduce the utility's return. But if investor expectations of earnings have risen, she says the Commission "clearly" should not recognize them because of the possibility they <u>could</u> be the result of deviations from past test year amounts or unregulated revenue. *Id.*, 33:630-34:642. This is hardly a meaningful refutation of Mr. Moul's financial leverage adjustment.

Ms. Kight-Garlisch is wrong that a utility market-to-book ratio greater than 1.0 can mean only one of two things. "[T]here are other factors as well. General market sentiment, expectations regarding business combinations/restructuring, the market value of assets that exceed book value, changes in interest rates, and other factors influence market prices of stocks." Moul Reb., NS-PGL Ex. PRM-2.0 REV, 19:411-413. Moreover, Ms. Kight-Garlisch provides no evidence whatsoever to tie her theoretical concerns to the market-to-book ratios of the utility sample or the Utilities. *Id.*, 20:425-442. As such, Ms. Kight-Garlisch's arguments are speculative at best, and they merit no consideration by the Commission.

Mr. Thomas concurs with all of the financial theory underpinnings of Mr. Moul's financial leverage adjustment (Thomas, Tr. 1094:1 - 1095:17), but argues that the adjustment should not be made because "differences in the market and book values of a utility indicate that the utility already is earning more than its cost of equity capital." Thomas Dir., CUB-City Ex. 1.0, 32:786 - 33:787. Mr. Thomas asserts that there is evidence that utility commissions across the country have been granting returns that overstate the utility's cost of equity for years. *Id.*, 36:886 - 37:914. If Mr. Thomas had his way, the commissions would regulate utility rates so that their stock prices always equaled book value.

Mr. Thomas' position is misplaced on several scores. The fact is that utility stock prices are commonly above book value. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 28:620 - 29:632. They have been that way for most of the past 50 years, and commissions have been granting rate increases to utilities throughout this period. Moul Sur., NS-PGL Ex. PRM-3.0, 15:322-324. It is impossible to believe that so many commissions have been so wrong for so long. In fact, as Mr. Thomas acknowledged on cross examination, factors other than expected earnings influence stock prices, including general market sentiment, expectations regarding business combinations, the market value of the utility's assets, and changes in interest rates and ratemaking policies. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 19:411-413, 28:612-619; Kight-Garlisch Reb., Staff Ex. 18.0, 19:374-382; Thomas, Tr. 1092:7 - 1093:8.

Ms. Kight-Garlisch and Mr. Thomas point to past Commission decisions rejecting the financial leverage adjustment to DCF results. In its most recent statement, the Commission noted its "long history of applying its estimated market required rate of return on common equity to the book value, net original cost rate base for Illinois jurisdictional utilities." *In re Central Illinois Public Serv. Co.*, ICC Docket Nos. 02-0798, 03-0008, 03-0009 (Cons.), p. 87 (Order Oct. 22, 2003). The Utilities are not proposing to change this practice. Rather, in developing the market required return, the Commission should take the increased financial risk of the book value capital structure into account when using the market required rate of return on common equity.

The Commission rejected the financial leverage adjustment anew in the CIPS case because "[t]here is no evidence that this practice has ever served as an impediment to a utility's ability to raise capital or maintain its financial integrity." *Id.* With due respect, it is Mr. Moul's opinion that this explanation "has it backwards. The Commission should endeavor to determine an accurate cost of equity. A market-based cost of equity that is applied to a book value capital structure that has more financial risk than the market value capital structure is by definition inaccurate." Moul Reb., NS-PGL Ex. PRM-2.0 REV, 29:642-645.

For these reasons, the Utilities respectfully request the Commission to reconsider the financial risk adjustment, its sound theoretical underpinnings, and the uncontroverted evidence in this record that applying the DCF market results to the Utilities' book value capitalization will underestimate the investor's required return.

C. **Growth Rate**

Ms. Kight-Garlisch agreed with Mr. Moul that determining the investor required return with the DCF model "requires a growth rate that reflects the expectations of investors," and that analyst earnings growth forecasts are the best measure of those expectations. Kight-Garlisch Dir., Staff Ex. 6.0, 5:82-93; *see* Moul Dir., PGL Ex. PRM-1.0 REV, 23:489 – 24:526. Mr. Thomas claims that analyst forecasts are upwardly biased, and proposes the use of internal growth rates to calculate the DCF growth rate. Thomas Dir., CUB-City Ex. 1.0, 15:326-26:602.

Mr. Thomas' claim that analyst forecasts are upwardly biased is unfounded. Past concerns about analysts having a conflict of interest were resolved years ago by the separation of research and investment banking services provided by Wall Street firms pursuant to the Global Research Analysts Settlement. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 25:551-554. Moreover, as Ms. Kight-Garlisch pointed out, the studies Mr. Thomas cites "tend to report generalized findings and do not specifically suggest that growth rates for utilities are overstated relative to achieved growth." Kight-Garlisch Reb., Staff Ex. 18.0, 16:312-314. And the relationship of analyst growth forecasts to achieved growth is irrelevant to the task at hand, namely to determine "what the investors' true growth expectations are." *Id.,* 17:345-346. Indeed, "the rationality of investors' true growth expectations is not at issue." *Id.,* 17:342-343.

Mr. Thomas' proposal to use internal growth rates is simply inappropriate. Internal growth rates measure the growth in the book value per share of a company, but book value also changes through the sale and repurchase of shares of stock. Book value per share is not a correct focus of the DCF growth rate because stock does not trade at a constant market-to-book multiple. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 27:585-594.

Mr. Thomas did not rebut these challenges to his DCF growth rate issues.

D. Dividend Growth and Compounding (Quarterly v. Annual)

A normal adjustment to the DCF dividend yield is to account for the compound returns attributed to quarterly dividend payments, which investors have the opportunity to reinvest. Moul Dir., PGL Ex. PRM-1.13C, 7:233 – 8:245. Mr. Thomas argues that this adjustment results in an upward bias, and presses for the use of an "annual" DCF model instead. Thomas Dir., CUB-City Ex. 1.0, 28:647 - 31:740. Again, the very purpose of the DCF model is to estimate the investor's expected return, and that return includes an expectation of quarterly dividend payments. The dividend adjustment recognizes this reality. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 27:603 - 28:608. The adjustment is also necessary to ensure that a utility recovers its true cost of common equity. Kight-Garlisch Reb., Staff Ex. 18.0, 18:368-373. For these reasons, the Commission has rejected the use of an annual DCF model in previous cases. *E.g., Citizens Utility Bd. v. ICC*, 291 Ill. App. 3d 300, 308 (1997) (affirming Commission's rejection of annual DCF model as supported by substantial evidence).

Mr. Thomas did not rebut these objections to an annual DCF model.

E. The Reality Check

One of Mr. Moul's practical recommendations is that the analyst review his or her model results for fundamental reasonableness. Mr. Moul observed that three of Ms. Kight-Garlisch's DCF results for utilities in the sample approached and even fall short of the cost of debt. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 12:253-13:272. Contrary to Ms. Kight-Garlisch's rebuttal (Kight-Garlisch Reb., Staff Ex. 18.0, 6:116 – 7:130), Mr. Moul did not recommend that these results be ignored. Rather, the existence of such results indicates that there is something seriously wrong with Ms. Kight-Garlisch's application of the DCF model in this case. *Id.*, 13:271-272; *see also* Moul Sur., NS-PGL Ex. PRM-3.0, 8:169 - 170.

Indeed, Ms. Kight-Garlisch's DCF model generated a rate of return of only 5.91% for Nicor, which is less than current utility bond yields. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 12:253-257. This cannot possibly be correct because Nicor's cost of equity cannot be less than its cost of debt. After all, the Commission set Nicor's return on equity at 10.51% just two years ago. Ms. Kight-Garlisch provided no explanation for this clearly unrealistic result. She instead pointed to an equally unrealistic result for Nicor from her CAPM analysis, and asserted that the average of the two unrealistic results provides a valid indicator of the investor required return. Kight-Garlisch Reb., Staff Ex. 18.0, 8:151-162. As Mr. Moul noted, "missing the target by ten feet to the right on the first try, followed by a miss of ten feet to the left on the second try, does not equal an average 'bull's eye.'" Moul Sur., NS-PGL Ex. PRM-3.0, 8:181-183. Nor did Ms. Kight-Garlisch explain how her financial models could average out to 10.37% for Nicor, but generate results 67-87 basis points lower for the Utilities.

II. <u>CAPM Model</u>

The CAPM model determines an expected rate of return on a security by adding to the risk-free rate of return a risk premium which is proportional to the non-diversifiable, or systematic, risk of the security. Moul Dir., PGL Ex. PRM-1.13G, 1:835-837 This model requires three inputs to compute the cost of equity: (1) the risk-free rate of return, (2) a "beta" measure of systematic risk, and (3) the market risk premium derived from the total return on the market for equities minus the risk-free rate of return. Moul Dir., PGL Ex. PRM-1.0, 37:811-814.

For the risk-free rate of return, Mr. Moul used historical and forecasted yields on 20-year Treasury bonds. Long-term government securities are appropriate for this exercise because of the long-term horizon of utility investments. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 13:274 - 15:310. Mr. Moul selected a return, 5.25%, within the range of those yields. Moul Dir., PGL

Ex. PRM1.0, 38:841 - 39:855. For the beta measurement of systematic risk, he started with the average *Value Line* beta for the utility sample and applied a formula to adjust the beta to reflect the utility's book value capital structure used in rate making. *Id.*, 37:819 - 38:840. This is another form of the financial leverage adjustment he made in his DCF model. His "leveraged" beta was 1.00 for the utility sample, indicating that the group's systematic risk with book value capital structures is equal to the market's risk in general. He developed the market premium of 6.60% by averaging historical and forecasted equity market performance derived from widely available data sources routinely used by investors and analysts. *Id.*, 39:856 - 40:888. With these inputs, he calculated a CAPM cost of equity of 12.04%. *Id.*, 40:889 - 41:896.

The CAPM model has limitations that make its use for setting authorized utility rates of return problematic. Foremost, for equities that are less risky than the market, as most utility stocks are, the CAPM model underestimates investor return expectations. Moul Dir., PGL Ex. PRM-1.13G, 1:840-845; *see also* Kight-Garlisch Reb., Staff Ex. 18.0, 19:388-391. In addition, some challenge the assumption underlying the model that diversifiable or unsystematic risk will be diversified away, and, therefore, is unimportant to investors. Moul Dir., PGL Ex. PRM-1.13G, 1:846-851. Also, the model's assumption that the average investor has a well-diversified portfolio cannot be proved. *Id.*, 1:851-2:855. Mr. Thomas also identified problems with the model, noting that it "has been seriously challenged in the academic literature" and that asserting it "provides a very unreliable estimate of the cost of capital." Thomas Dir., CUB-City Ex. 1.0, 41:1003-1007.

A. <u>Use of Historical Data</u>

Despite her objection to Mr. Moul's use of historical data in the market models, Ms. Kight-Garlisch relied on 60 months of historical data to calculate her CAPM betas. She claimed that betas cannot be calculated in any other manner (Kight-Garlisch Reb., Staff Ex. 18.0, 11:224-225), but this is not correct. "Use of historical data for calculating betas would only be appropriate for determining expected systematic risk if it is demonstrated that betas are stable over time" (Moul Sur., NS-PGL Ex. PRM-3.0, 10:209-210), and Ms. Kight-Garlisch made no such showing. To the contrary, betas for utilities computed with historical data have been trending upward for several years. *Id.*, 10:213-214.

Ms. Kight-Garlisch challenges Mr. Moul's use of historical data to develop the investor required return using, in part, historical earned returns in the CAPM model. By contrast, she determined her risk-free rate and market premium based on the single-day spot stock and bond prices on April 25, 2007. Each of her three criticisms of Mr. Moul's approach can be turned against Staff's single-day spot market data approach.

Her first criticism is that "the returns an investment generates are unlikely to have equaled investor return requirements due to unpredictable economic, industry-related, or company-specific events." Kight-Garlisch Dir., Staff Ex. 6.0, 30:556-558. The same events render a single day's stock or bond price volatile and unlikely to equal the investor required return on that day, much less months later.

Her second criticism is "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." Kight-Garlisch Dir., Staff Ex. 6.0, 30:558-562. The same can be said with respect to months-old stock and bond prices. Indeed, between April 25th and July 27th, the risk-free interest rate increased by almost 30 basis points. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 15:311.

Her third criticism is that "the magnitude of the historical risk premium depends upon the measurement period," and the selection of the period is "susceptible to manipulation." Kight-Garlisch Dir., Staff Ex. 6.0, 30:565-567. Likewise, the magnitude of the single-day spot premium depends on the day, and the selection of that day is also susceptible to manipulation. The use of long-term historical averages to determine the equity risk premium smoothes out the impact of "unpredictable economic, industry-related, or company-specific events," and the associated changes in risks and prices. Thus, historical averages are less susceptible to manipulation, given the volatility of stock and bond prices. *See* Moul Reb., NS-PGL Ex. PRM-2.0 REV, 9:181-194.

B. Risk-Free Rate of Return

There is general agreement among the cost of equity witnesses that the rates on United States Treasury instruments are the appropriate measurement of the risk-free rate of return in the CAPM model. Mr. Moul (Moul Dir., PGL Ex. PRM-1.0 REV, 38:841-39:855) and Mr. Thomas (Thomas Dir., CUB-City Ex. 1.0, 55:1344-1346) agree that long-term Treasury bonds are the most appropriate, while Ms. Kight-Garlisch relies on short-term Treasury bills. Kight-Garlisch Dir., Staff Ex. 6.0, 9:161-11:217. In this rate case the debate between long- and short-term Treasuries makes little difference due to the flat yield curve between them. *See Id.*, 11:213-214.

C. Beta Estimates

Mr. Moul takes issue with Staff's "regression" betas, not because they are theoretically unsound but because they are unnecessary. Betas are calculated and published by *Value Line* and other sources, and provide objective information that sophisticated investors rely on. By contrast, Staff's uniquely derived betas are irrelevant to the investor's required return precisely because they are not available to, and therefore not relied upon, by investors. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 15:327 - 16:338. Ms. Kight-Garlisch responds that it does not matter whether investors rely on Staff's beta estimates, but whether they are "generally accepted," and for that acceptance points to numerous cases in which the Commission has accepted them. Kight-Garlisch Reb., Staff Ex. 18.0, 12:231 - 13:260.

In this case, Staff is deciding what investors should expect, not what they do expect. Staff's derivation of unique betas, and the Commission's acceptance of them, is inconsistent with the Commission's admonishment that it "reacts to the investor, and not vice versa." *In re Illinois Bell Tel. Co.,* ICC Docket No. 92-0448, 93-0239 (Cons.), p. 103 (Order Oct. 11, 1994).

Mr. Thomas attacks the adjustments made to "raw" betas by both *Value Line* and Ms. Kight-Garlisch that are intended to solve one of the problems with the CAPM model: "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." Kight-Garlisch Reb., Staff Ex. 18.0, 19:388-391. Mr. Thomas' suggestion that the adjusted betas calculated by *Value Line* and Staff are biased (Thomas Reb., CUB-City Ex. 2.0, 10:230-232) is unfounded. To the contrary, as the Commission has previously held, using unadjusted betas in the CAPM model "would cause a downward bias in cost of common equity estimates and cannot be relied on." *In re Central Ill. Light Co.,* ICC Docket Nos. 06-0070, 06-0071 (Cons.), p. 144 (Order Nov. 21, 2006) (emphasis added).

Ms. Kight-Garlisch and Mr. Thomas raise the same objections to Mr. Moul's financial leverage adjustment to his CAPM beta estimate as they do for his similar adjustment to his DCF result. The arguments on both sides are similar, and will not be repeated here.

D. Market Risk Premium

Mr. Thomas urges the use of a market risk premium of 5.00% (Thomas Dir, CUB-City Ex. 1.0, 54:1324-1333), which is significantly lower than the premiums calculated by Mr. Moul and Ms. Kight-Garlisch. In support of his lower premium, Mr. Thomas cites various academic studies. The Utilities concur in Ms. Kight-Garlisch's observation that the research Mr. Thomas cites "represents various academics' opinions of the equity risk premium investors should expect, which is not necessarily the same as what the investors truly are expecting," and that the latter is the Commission's appropriate focus. Kight-Garlisch Reb., Staff Ex. 18.0, 20:407-409.

III. Risk Premium Model

The Risk Premium model measures the cost of equity by determining the degree to which equity is more risky than corporate debt, and adding the compensation associated with that additional risk, the equity risk premium, to the interest rate on long-term debt. PGL Ex. PRM-1.13F, 1:697 - 2:725. This model has its limitations because analysts often cannot agree on the future cost of corporate debt and the measurement of equity risk premium. Moul Dir., PGL Ex. PRM-1.0 REV, 31:682-685.

Mr. Moul estimated a 6.25% prospective yield on A-rated utility bonds, based on recent historical data and forecasts published by *Blue Chip*, "a widely-available and utilized source [that] contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services." Moul Dir., PGL Ex. PRM-1.0, 31:686 - 33:732. For the equity risk premium, he compared market returns on utility stocks and bonds over various historical periods using the S&P Public Utility Index, and arrived at a 5.00% premium that includes an adjustment for the lower overall risk of the utility sample compared to the S&P index. *Id.*, 33:733 - 36:791. Mr. Moul's RP model yields a rate of return for the

Utilities of 11.44%, which falls between his DCF (9.53%) and CAPM (12.04%) results. *Id.*, 36:792-797.

Neither Ms. Kight-Garlisch nor Mr. Thomas used this model to calculate the Utilities' cost of equity, but they took issue with Mr. Moul's.

A. Common Equity Risk Premium

Aside from his use of historical data generally, Ms. Kight-Garlisch challenged Mr. Moul's use of historical public utility bond yields because he did not demonstrate that they are "equivalent" to the A-rated bond yield. Kight-Garlisch Dir., Staff Ex. 6.0, 32:605-607 However, Ms. Kight-Garlisch did not demonstrate that this would make any difference. She also claimed that Mr. Moul did not provide "quantitative support" for adjusting the S&P Public Utilities equity risk premium downward to reflect the lower risk of the utility sample. *Id.*, 32:607-610 While Mr. Moul's adjustment reflects an exercise of judgment, it is an informed one, based on "differences in risk fundamentals represented by an analysis that considered size, market ratios, common equity ratio, return on book equity, operating ratios coverage, quality of earnings, internally generated funds and betas." Moul Reb., NS-PGL Ex. PRM-2.0 REV, 17:357-359. It is difficult to understand what more Ms. Kight-Garlisch would have needed to agree with Mr. Moul's judgment.

Mr. Thomas accuses Mr. Moul of "selectively" choosing the historical time periods to use (Thomas Dir., CUB-City 1.0, 58:1411-59:1429), but does not back it up with any evidence. To the contrary, Mr. Moul selected his time periods based upon events that are "fixed in history and cannot be manipulated as later financial data becomes available," and has used these same periods consistently in his work. Moul Dir., PGL Ex. PRM-1.0 REV, 35:761-772. He gave greater emphasis to the more recent data periods so that his equity risk premium would most likely reflect "the market fundamentals most likely to exist for the future." Moul Reb., NS-PGL Ex. PRM-2.0 REV, 16:345-347. Mr. Moul's methodology is beyond reproach.

IV. Adjustments to the Model Results

A. Staff's "Financial Risk" Adjustment

Ms. Kight-Garlisch's DCF and CAPM market models produced costs of equity of 8.23% and 11.34%, respectively. Kight-Garlisch Dir., Staff Ex. 6.0, 16:298-300. She took the average of these two results (9.79%) and then applied an adjustment for "financial risk" that Staff has performed, and the Commission has accepted, in prior cases. The adjustments in this case, a 29-basis point downward adjustment for North Shore and a 9-basis point downward adjustment for Peoples Gas, are purportedly "to reflect the lower [financial] risk of the Companies relative the Utility Sample." *Id.*, 16:306-311. The consideration of financial risk involves a comparison of the Utilities' stand-alone S&P credit rating to the S&P credit ratings of the companies in the utility sample. *Id.*, 17:326 - 22:412.

There is a fundamental methodological problem with Staff's financial risk adjustment, a problem that the Commission perhaps has not considered in prior cases. Ms. Kight-Garlisch accepted Mr. Moul's utility sample as a reasonable proxy for "operating" risk but not "financial" risk, despite the fact that Mr. Moul in assembling his sample expressly evaluated the comparability of credit ratings, which reflect both operating and financial risk. Moul Dir., PGL Ex. PRM-1.0 REV, 9:185-203, 10:226 - 11:240. Ms. Kight-Garlisch noted that the proxy group was similar enough to the Utilities on the percentage of assets dedicated to gas operations and S&P business profile score. Kight-Garlisch Dir., Staff Ex. 6.0, 3:45 – 47. There is no evidence, however, that she reviewed and confirmed the similarity of the Utilities to the proxy group on any of the many other parameters Mr. Moul used to first select and then confirm the appropriateness of his sample as a proxy.

In order to select the proxy group, Mr. Moul began with six screening criteria:

> Local distribution companies;
>
> Publicly traded with stock listed on the New York Stock Exchange;
>
> Contained in The Value Line Investment Survey in the "Natural Gas Distribution" industry group;
>
> A history of dividend increases over the period 2001-2005;
>
> Not currently the target of a merger or acquisition; and
>
> Have at least 70% of their assets dedicated to gas operations.

Moul Dir., PGL Ex. PRM-1.0 REV, 7:155 - 8:161. In order to confirm the comparability of his proxy group to the Utilities, Mr. Moul then reviewed_the credit ratings of the proxy group for comparability, which he found comparable to the Utilities. Moul Dir., PGL Ex. PRM-1.0 REV, 9:193 – 203. He also reviewed a number of other parameters for comparability, including size, market ratios, common equity ratio, variability of return on book equity, operating ratios, interest coverage, quality of earnings, internally generated funds, and beta coefficients. *Id.*, 10:204 - 13:286; PGL Exs. PRM-1.2, PRM 1.3, PRM 1.4. While some risk factors of the Utilities were slightly higher or lower than the proxy group, Mr. Moul concluded: "On <u>balance</u>, the risk factors <u>average out</u>, indicating that the cost of equity for the utility sample would provide a reasonable basis for measuring the [Utilities'] cost of equity." Moul Dir., PGL Ex. PRM-1.0 REV, 14:294-296 (emphasis added). Neither Ms. Kight-Garlisch nor Mr. Thomas took issue with Mr. Moul's conclusion.

Only after running the DCF and CAPM market models with Mr. Moul's proxy group did Ms. Kight-Garlisch then analyze whether the Utilities and the proxy group were comparable on a credit rating basis. By singling out credit rating and not any of the other comparability parameters that Mr. Moul considered in building the proxy group, Ms. Kight-Garlisch suggests that the risks of the proxy group did not in fact "average out" and therefore could not provide a reasonable basis for her market models. This calls into question her market model results. If, in hindsight, Mr. Moul's proxy group was not sufficiently comparable with respect to credit rating, then it may not have been comparable as to other comparability factors. Or, differences on other factors could have offset the lack of comparability on credit rating. Because she did not perform that analysis, Ms. Kight-Garlisch's assertion that credit rating requires special consideration for non-comparability lacks an evidentiary basis and must be rejected.

This is another example of Staff wanting it both ways. Ms. Kight-Garlisch accepted Mr. Moul's utility sample for purposes of running the market models, but reserved the right to adjust the results for one of the many comparability factors on which the sample was based. If Ms. Kight-Garlisch did not believe that Mr. Moul's proxy group reflected comparable risk, operational and/or financial, then it was incumbent on her to use a different proxy group that reflected a "balance" of both operational and financial risk as compared to the Utilities.

In addition, Ms. Kight-Garlisch's application of Staff's financial risk adjustment in this case is not consistent with her position on Mr. Moul's financial leverage adjustment. The Staff adjustment is based on credit rating differences between the Utilities and the utility sample, and is therefore intended to reflect differences in financial risk. The adjustment is based on the same Modigliani-Miller principle as Mr. Moul's financial leverage adjustment to his DCF model result and CAPM beta: as a firm's debt increases, the required return on equity also increases. *Compare* Moul Dir., PGL Ex. PRM 1.0 REV, 27:603-604, *with* Kight-Garlisch Reb., Staff Ex. 18.0, 4:74-75. In each case, the cost of capital witness adjusted the Utilities' rates of return to reflect their capital structures, in particular their debt leverage. Staff cannot have it both ways. It cannot ignore the differences in capital structures reflected by its market model results and the Utilities' book value capital structures, while at the same time adjusting another market model's results to reflect the Utilities' debt leverage as reflected in their credit ratings.

Another aspect of arbitrariness in Staff's financial risk adjustment is the unexplained differential treatment of North Shore and Peoples Gas. Staff proposes adjustments that differ by over three-fold, despite the fact that the two utilities have had the same credit ratings for at least the past five years. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 21:468 - 22:472. If there should be any disparate treatment between the two, there should be an upward adjustment of North Shore's ROE to reflect its small, <u>stand-alone</u> size. Moul Reb., NS-PGL Ex. PRM-2.0 REV, 21:448 - 454; Moul Sur., NS-PGL Ex. PRM-3.0, 6:125 - 135.

For these reasons, the Commission should reconsider its past acceptance of the Staff financial risk adjustment to market model results based on the credit ratings of companies in the proxy group and the utility. If the proxy group is not similar enough to the utility in <u>both</u> operating and financial risk, it is not a valid proxy group. Staff cannot accept the Utilities' proxy group as having the same <u>balance</u> of risks as the utility and using that group for the market models, but then adjust the market model results due to a claimed differential in one of the many risk parameters that go into that balance. If the Commission does accept Staff's financial risk adjustment in this case, for the sake of consistency it should also endorse Mr. Moul's financial leverage adjustment in the DCF and CAPM models.

B. Effect of Proposed Decoupling and Uncollectibles Riders

Staff and CUB-City argue that if the Commission approves the Utilities' proposed Riders VBA and UBA, the Utilities' authorized rates of returns should be reduced to reflect the reduced risk to the Utilities resulting from these riders. Neither Ms. Kight-Garlisch nor Mr. Thomas, however, made any evidentiary showing that the approval of these rate mechanisms would have any impact on the investor-required return, theoretical or otherwise. Instead, Staff and CUB-City simply assume there will be an impact and suggest methodologies to calculate the reduction. For this reason alone, the proposed adjustments must be rejected.

Mr. Moul's testimony that the existence or non-existence of the riders do not affect the investors required return was not rebutted by either Staff or CUB-City. "The financial theory upon which the cost of equity is based recognizes that investors value their investments on a long-term basis covering a number of years, not just one year." Moul Dir., PGL Ex. PRM-1.0 REV, 5:111-113. This observation is confirmed by the theoretical underpinnings of the market models. The DCF model expressly assumes a growth rate that approaches infinity. The CAPM model expressly ignores company-specific, "unsystematic," risks. "Accordingly, <u>the investor required cost of capital or discount rate assumed for an investment in a gas utility is not affected by variations in usage due to weather</u> and therefore is the same either with or without a VBA rider." *Id.*, 6:123-126 (emphasis added).

Both riders can have only short-term benefits (and liabilities), and therefore can affect only their credit ratings. *Id.*, 6:127-7:137. For example, "[w]eather, by definition, is normal over the long-term or multi-year period, although it may vary significantly from year to year." *Id.*, 6:116-118. Neither Ms. Kight-Garlisch nor Mr. Thomas provided any basis in financial theory, or otherwise, to support their view that company-specific risks like weather or uncollectibles can or should be recognized in the Utilities' authorized rates of return.

Nor do they seem willing to recognize that the riders are <u>risk neutral</u>. The riders would protect shareholders and ratepayers alike from the risk of variations from the "normal" assumptions for weather and uncollectibles used for ratemaking purposes. For example, while Rider VBA would protect the Utilities if weather was warmer than assumed in their rates, if weather was colder than assumed in their rates the rider would protect ratepayers from overpaying fixed charges for gas service. Why do the Staff and CUB-City witnesses focus exclusively on the riders' potential benefits to shareholders? A cynic might conclude that Staff, CUB and the City assume that the Commission will set the "normal" assumptions for the Utilities' rates in a manner that will not be symmetrical, but will instead be skewed so that the Utilities will most probably lose out due to variations from the unrealistic assumptions built into their base rates.

Even if it had been shown in this case that the riders affect the investor's required return (it wasn't), and even if the riders reduced only the shareholder's risk (they don't), the majority of companies in the utility sample used by all three cost of capital experts already have similar mechanisms and their financial data therefore already reflect that fact. The Missouri Public Service Commission recently refused to adjust a gas utility's authorized rate of return for precisely this reason. *Atmos Energy Corp.,* GR-2006-0387, 2007 MO. PSC Lexis 278, **12-13 (Feb. 22, 2007).

If the authorized rates of return for the Utilities are to be based on the financial parameters of the utility sample, then logic can only suggest that the rates should be <u>increased</u> if the proposed riders are <u>not</u> approved. At least one state commission has increased a gas utility's authorized rate of return because the company did not have a weather normalization rider. *Yankee Gas Serv. Co.,* Docket No. 01-05-19PH01, 215 P.U.R.4th 185, 2002 WL 554356 (Conn. D.P.U.C. Jan. 30, 2002). Only then would the Utilities' equity cost reflect the appropriate level of risk compared to the utility sample.

Ms. Kight-Garlisch challenged this logic, arguing that because the Utilities, which lack such riders, already have similar risk compared to the utility sample as measured by S&P's business profile scores, their ROEs should be reduced if the riders are approved. Kight-Garlisch Dir., Staff Ex. 6.0, 24:444-26:478; Kight-Garlisch Reb., Staff Ex. 18.0, 6:102-114. In making this argument, Ms. Kight-Garlisch proves Mr. Moul's main point that such riders do not affect the investor's required return because weather and uncollectibles are not business risks that investors take into account. However, even if it is assumed that the existence of the riders would affect the cost of equity, Ms. Kight-Garlisch provided no evidence to support her assumption that the approval of the proposed riders would cause S&P to increase the Utilities' business profile score a full notch to 2. Thus, Ms. Kight-Garlisch's testimony regarding this effect is speculative and not worthy of further consideration.

Finally, Mr. Thomas attempted to measure the financial risk impact of the riders by comparing them to the value of weather insurance policies the Utilities' corporate parent purchased in the past to protect shareholders against earnings shortfalls in the event of significantly warmer weather than forecasted in the Utilities' rates. As Mr. Schott explained, Mr. Thomas' "analysis" – which amounted to taking the maximum payout under one of the policies, deducting the premium paid, and characterizing the net payout as the value of the policy – is fatally flawed. The value of an insurance policy involves not only consideration of the payout and premium, but also the probability of the payout. The value of the policy is therefore represented by the premium amount, which "should equal the average expected payout less administrative costs." Schott Reb., NS-PGL Ex. JFS-2.0, 6:111-112. In addition, Mr. Thomas' analysis did not consider the fact that the weather insurance policy required Peoples Energy Corporation to pay an additional premium if weather was somewhat colder than forecasted (akin to Rider VBA requiring refunds). There is nothing in his analysis that shows the financial impact of Peoples Energy Corporation paying additional insurance premiums if the weather was colder than normal. Thomas Tr. 1099:15 - 1101:19. Under Rider VBA the "payout" to the Utilities if weather is warmer than forecasted, and the "payout" is to ratepayers if weather is colder, occurs with any variation from the forecast.

V. Consideration of Investor Expectations

As employed by the parties, the market models generated costs of equity ranging from CUB-City's 7.42-8.11% to Staff's 9.50-9.70% to the Utilities' 11.06%. How is the Commission to decide the pinpoint returns for the Utilities within this wide range? As Ms. Kight-Garlisch testified, the Commission's task is to determine what "investors truly are expecting," not what "investors should expect." Kight-Garlisch Reb., Staff Ex. 18.0, 20:408-409.

The recommendations of Staff and CUB-City reflect an overly-mechanistic reliance on the market models. Staff adjusts its market model results, but only to reflect what Staff believes is a shortcoming in the proxy group used to generate those results. CUB-City urge the acceptance of their "unadjusted" DCF result. In each case, the Commission is being told to set the Utilities' rates of return based on what "investors should expect," not on what "investors truly are expecting."

The Staff and CUB-City recommendations take no account of the information that sophisticated investors routinely rely upon <u>in addition to</u> the market models. In determining where it should set the Utilities' rates of return within the range of valid market model results (e.g., those presented by Mr. Moul), the Commission should consider (1) other rates of return recently allowed for other gas utilities in Illinois and the United States and (2) developments in the financial markets since the cost of capital experts' analyses were performed.

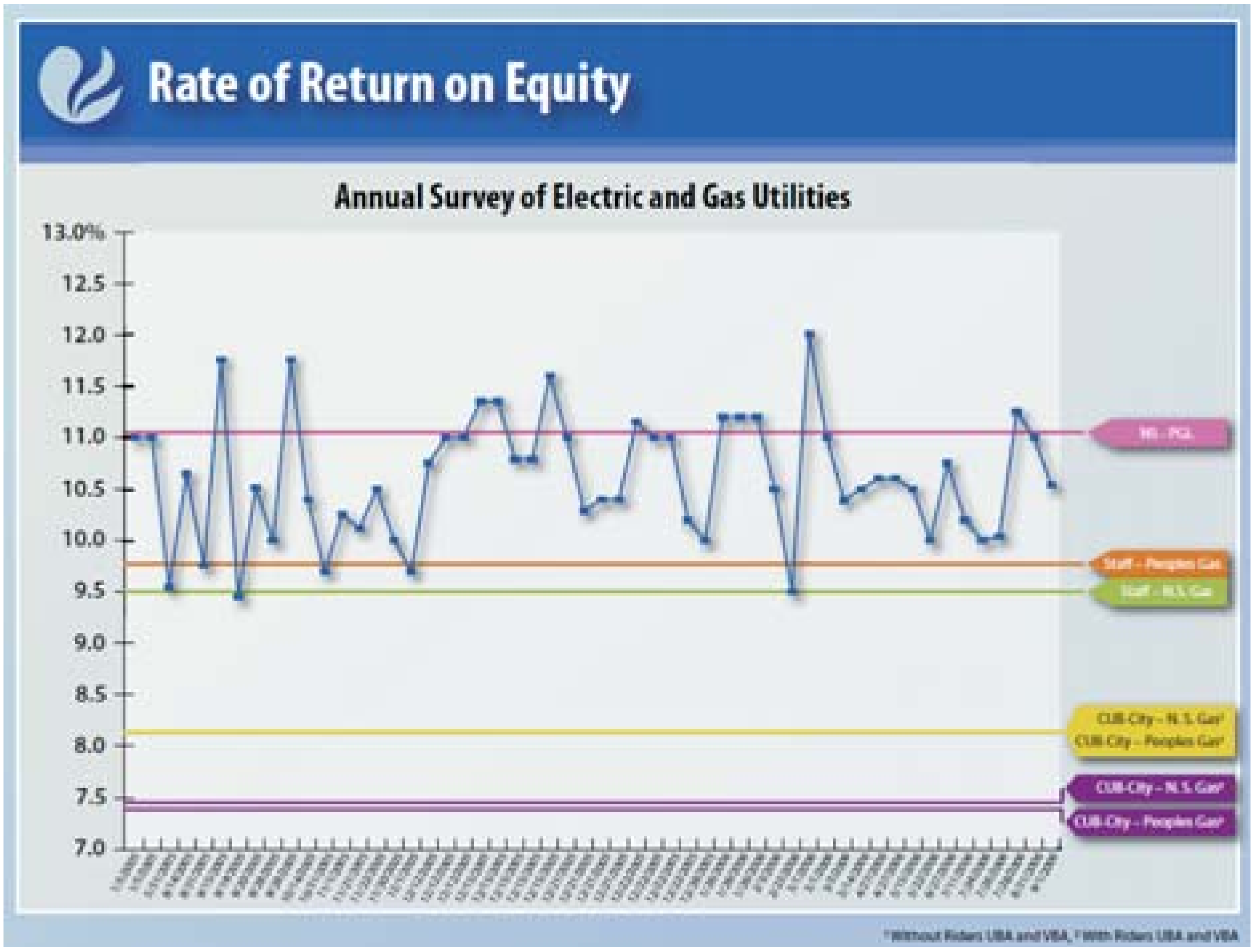
A. <u>Other Recently Allowed Rates of Return on Equity</u>

Rates of return on equity awarded to gas utilities in the United States averaged in the mid-10% range in 2006, and 10.35% through March 2007. Moul Reb., NS-PGL Ex. 2.0, 3:60 - 4:80; NS-PGL Ex. PRM-2.2. *Value Line* forecasts the natural gas utility industry to earn 11.5% in 2007 and 2008. Moul Reb., NS-PGL Ex. 2.0, 5:91-96. Also relevant is the Commission's last decision for an Illinois gas utility subsidiary of a large public utility holding company, 10.51% for Nicor Gas Company in late 2005. *Nicor*, at pp. 84-88.

In highlighting this information, the Utilities are in no way suggesting that their rates of return should be based exclusively on the returns set for other utilities. Only then would the kind of a point-by-point analysis of every return and utility, as Ms. Kight-Garlisch argues should be required. Kight-Garlisch Reb., Staff Ex. 18.0, 14:278-15:296. Rather, this is general information that the Commission should take into consideration in setting the Utilities' rates of return. Moul Sur., NS-PGL Ex. PRM-3.0, 11:233-238; *see also* Moul, Tr. 1051:3-14, 1052:1-10, 1079:15 - 1081:3. It is beyond dispute that these results, "rendered within a regulatory framework that is very similar from state to state, … have an influence on what investors expect from companies operating in that industry." Moul, Tr. 1043:2-14.

Taking this information into account, it is clear that the CUB-City recommendations are not even in the ballpark of reasonable returns. Staff's sub-10% position is unreasonably low, lower than the rate of return awarded any gas utility in Illinois in at least 30 years. Only the Utilities' 11.06% is within the range of investor-expected returns.

To put the parties' respective positions into perspective, the following table (using data from NS-PGL Ex. PRM-2.2 and inserting the Utilities, Staff, and CUB-City positions) illustrates the relationship of their positions to other recent rate of return decisions:



B. <u>Recent Events</u>

As discussed above, there have been significant developments in the financial markets since all three of the cost of capital experts performed their market model analyses. Stock price volatility has risen to its highest level since 2003. Moul Sur., NS-PGL Ex. PRM-3.0, 4:77-78. Utility bond yields have risen to their 5-year high. Moul Reb., NS-PGL Ex. PRM-2.1. The Commission should take these developments into account when it sets the Utilities' rates of return in early 2008 for 2008-2009 and perhaps longer. On this record, rate of return determinations based on nine month-old spot single-day market data as proposed by Staff would be arbitrary and unreasonable.

If the Commission continues to adhere to Staff's single-day spot approach for selecting inputs for the market models, the recent volatility in the capital markets demands a process for updating when rate cases take the better part of a year to resolve. Updating is feasible if not mandatory in today's financial environment.

D. <u>Flotation Costs</u>

Peoples Gas and North Shore witness Mr. Moul included in each of his market model results a standard adjustment for the "flotation" costs associated with the issuance of new common stock, namely the underwriting discount and company issuance expenses. Moul Dir., PGL Ex. PRM-1.0, 28:625-631, 36:795-796, 41:891-892; *see* PGL Ex. PRM-1.13D, 1:403-404. Mr. Moul based his 19-point adjustment on the 3.9% average flotation costs incurred by the utilities in the utility sample during the period 2001-2005. *Id.*, 2:425 - 3:433; PGL Ex. PRM-1.8.

Staff witness Ms. Kight-Garlisch, citing prior Commission decisions, argue that the Utilities had to prove that they would issue stock in the test year or they incurred flotation costs were not recovered previously through rates. Kight-Garlisch Dir., Staff Ex. 6.0, 26:479 – 27:497. However, she ignored that the Utilities provided evidence of the flotation costs they have previous incurred and not recovered through prior rates, totaling $485,000 each. NS Ex. BAJ – 1.3; PGL Ex. BAJ – 1.3.

If the Commission does not adopt Mr. Moul's flotation cost adjustment, then it should at least authorize an adjustment that allows the Utilities to recover their unrecovered flotation costs.

E. <u>Weighted Average Cost of Capital</u>

1. <u>Peoples Gas</u>

As stated earlier, Peoples Gas proposes an overall rate of return of 8.24% on its rate base. That rate of return is based on its capital structure containing 56% common equity at a cost of common equity of 11.06% and 44% long-term debt at a cost of 4.67%. The derivation of Peoples Gas' proposed overall rate of return is summarized in the following table (based on NS-PGL Ex. BAJ-2.1P):

Peoples Gas Cost of Capital Summary			
Cost of Capital	**Percent of Total**	**Percent Cost**	**Weighted Cost**
Long Term Debt	44.00%	4.67%	2.05%
Common Equity	56.00%	11.06%	6.19%
Total Capital			8.24%

For the reasons discussed above, the overall rate of return of 8.24% should be approved.

2. <u>North Shore</u>

As stated earlier, North Shore proposes an overall rate of return of 8.56% on its rate base. That rate of return is based on a capital structure containing 56% common equity at a cost of 11.06% and 44% long-term debt at a cost of 5.39%. The derivation of North Shore's proposed overall rate of return is summarized in the following table (based on NS-PGL Ex. BAJ-2.1N):

North Shore Cost of Capital Summary			
Cost of Capital	**Percent of Total**	**Percent Cost**	**Weighted Cost**
Long Term Debt	44.00%	5.39%	2.37%
Common Equity	56.00%	11.06%	6.19%
Total Capital			8.56%

For the reasons discussed above, the overall rate of return of 8.56% should be approved.

V. <u>HUB SERVICES</u> (All issues relating to Hub services)

The Hub is a group of interstate gas transmission and storage services available to wholesale customers. Hub services are made available by Peoples Gas using portions of the capacity at Peoples Gas' underground storage facility, Manlove Field, and Mahomet Pipeline. Peoples Gas charges the customers that use these Hub services at rates approved by the Federal Energy Regulatory Commission, and the resulting revenues are credited to retail customers through the purchased gas adjustment clause (Rider 2). The revenue benefit credit to the Hub is a benefit to all sales customers on the utility system.

Staff, through its witnesses Dennis Anderson and David Rearden, argues that the Hub actually loses money, and is therefore imprudent to operate. The facts do not bear out this claim. Staff appears to urge that the revenues from the Hub should be compared to the cost of the cushion gas that Peoples Gas might arguably have injected into Manlove Field to support the expanded storage activities there. Staff's argument has the feel of a cross-subsidization claim, i.e., that Peoples Gas has not been attributing the right costs to the Hub, thereby somehow compromising the interests of ratepayers. It bears repeating that the Hub is part of Peoples Gas, and any revenues that it receives only serve to lower the cost of gas for all ratepayers. Moreover, the Hub services are a part of the integrated utility system. There is not and never has been any construction of facilities to serve Hub customers or a separate cost of service which could be attributed to Hub services. Staff's position is merely an attempt to isolate a part of the integrated utility system as though it were built to serve only Hub services transportation and storage customers and as if the facilities used to serve Hub customers could be separately identified.

A. <u>Manlove Field</u>

Manlove Field an underground aquifer, that is, porous rock with water in the pores. Puracchio Dir., PGL Ex. TLP-1.0, 3:47-55. Gas can be injected through various wells, displacing the water. Some of this gas becomes trapped, and is never recovered, but some of the injected gas (interchangeably called "working gas" or "top gas") can be withdrawn, and the field is therefore useful for storage. Puracchio Dir., PGL Ex. TLP-1.0, 10:213-220. This gas-trapping phenomenon is most pronounced when an area of an aquifer first has gas pumped into it. On subsequent injections, relatively less gas becomes trapped. Puracchio Reb., PGL Ex. TLP-2.0, 10:199-213. An area of the aquifer that has never had gas in it is known as virgin aquifer. *Id*. at 206-207. Operations at Manlove have an annual cycle: during the summer season, gas is injected into the aquifer, and during the winter heating season, gas is withdrawn for customers. Puracchio Dir., PGL Ex. TLP-1.0, 4:85-6:124. The amount of working gas that is injected and withdrawn each year is the amount of gas "cycled."

Staff and Peoples Gas agree that Manlove Field is particularly complex, even as aquifer storage fields go. Puracchio Dir., PGL Ex. TLP-1.0, 4:69-84. Manlove is large, inefficient (*i.e.*, a relatively high percentage of gas becomes trapped), and difficult to manage and characterize. Puracchio Dir., PGL Ex. TLP-1.0, 3:61-62; D. Anderson, Tr. at 472:14-15; 492:3-8. All that the engineers on the surface can do is to pump gas into the many injection wells and see how much gas comes back out. They cannot actually direct the gas to particular spots. "The gas goes where it goes." D. Anderson, Tr. at 478:14. This feature and the fact that the field has been used for gas storage operations for years renders it difficult to ascertain which areas of the aquifer are virgin aquifer and what areas have trapped gas. It is also difficult to determine whether new injections will invade virgin aquifer or previously invaded areas. Puracchio Sur., NS-PGL Ex. TLP-3.0, 10:211-220.

When Peoples Gas introduced the Hub services, it did not install additional wells or other facilities to enable it to provide the service. It merely expanded the amount of working gas at Manlove by injecting more gas into the storage field and increased working gas by 10.2 Bcf. D. Anderson Dir., Staff Ex. 10.0, 6:111-117.

The essence of Staff's argument is that Peoples Gas should have, but did not, inject more cushion gas to support the Hub operations. What Peoples Gas has done instead is to characterize a percentage of the gas it injects each day during the injection season as cushion gas. Puracchio

Dir., PGL Ex. TLP-1.0, 10:221-224. Some of that annual cushion gas allotment is supporting Hub operations, and the rest is supporting general storage operations at Manlove. Puracchio Sur., NS-PGL Ex. TLP-3.0, 6:132-7:149. While that distinction is of no particular importance to Peoples Gas (as the whole integrated field, whether supporting the Hub or not, belongs to Peoples Gas), because of Staff's argument, Peoples Gas has sought to estimate the amount of cushion gas that could be attributed to the Hub storage. That amount, shown on NS-PGL Ex. TLP-2.8, is approximately 1.34 MMDth.

To accept Staff's argument as correct, the Commission would need to find that the amount of gas Peoples Gas is injecting at Manlove each season for cushion purposes is insufficient. If that were true, Peoples Gas would notice, over time, that Manlove was not performing properly. D. Anderson, Tr. at 485:1-5. In operating an aquifer storage field, the operator watches various metrics such as pressure and peak deliverability, to see if the field is operating as expected (D. Anderson, Tr. at 485:20-486:6), and that is just what Peoples Gas has done. In each injection season for the past several seasons, Peoples Gas has classified 3.5% of gas as cushion gas.[17] Puracchio Dir., PGL Ex. TLP-1.0, 10:221-224; 11:229-243. In all, from 1997 through 2006, Peoples Gas capitalized an additional 7.88 MMDth of its Manlove injections as cushion gas. *Id.* at 11:225-228. Based on the various metrics used by Peoples Gas to assess the storage field's performance, this is keeping Manlove Field operating as expected. Puracchio Reb. NS-PGL Ex. TLP-2.0, 7:156 - 9:193. Staff argues that the need for a large, expensive

[17] There may some confusion in the record as to the level of cushion gas injections over the years, as Staff witness Mr. Anderson seemed to state that Peoples Gas had nearly doubled its injections recently. D. Anderson, Tr. at 490:17-491:2. That is not the case. Manlove field had a problem with its meters for some time, caused by the pulsation of the compressors. NS-PGL Ex. TLP-2.5. This meant that Peoples Gas was putting more gas into the field than it thought, and while Peoples Gas thought that it was injecting 2% cushion gas, and that 2% was enough, the real figure was likely over 3%. With new meters, and Peoples Gas reducing its cushion gas injections to a real 2%, the field's performance quickly started to drop. Peoples Gas increased its injections to 3.5%, and field performance has returned to normal levels. Puracchio Reb., NS-PGL Ex. TLP-2.0, 7:136-8:168.

cushion gas injection is just around the corner. However, Staff's argument is entirely speculative and is not supported by the evidence.

B. <u>Hub Services</u>

The Hub is comprised of two types of FERC- jurisdictional services. First, the Hub includes the transportation and storage 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. Zack Reb., NS-PGL Ex. TZ-2.0, 65:1458-1461. Peoples Gas received a Hinshaw Blanket Certificate in March, 1998 (The Peoples Gas Light and Coke Company, 82 FERC ¶62,145 (1998)) and the initial Operating Statement which included only transportation services was approved by the FERC in March, 1998 (The Peoples Gas Light and Coke Company, 82 FERC ¶62,145 (1998)). The FERC approved the filing with storage and parking and loaning services in March 1999 (The Peoples Gas Light and Coke Company, 86 FERC ¶61,226 (1999)). Service began immediately following the receipt of the operating approval. *Id*. at 66:1463-1467.

Hub rates associated with the services provided under the Operating Statement are developed and set according to the FERC rules. The most recent rates were established in FERC Docket No. PR07-1-000 and approved by FERC in March, 2007. The Peoples Gas Light and Coke Company, 118 FERC ¶61, 203 (2007); See also Zack Reb., NS-PGL Ex. TZ-2.0, 66:1476-1477. The rates for the other Hub services are established through negotiations with the counter parties and by means of a competitive bidding process in which the highest bidder wins. *Id.* at 66:1475-1478, Zack, Tr. at 512:5-19.

C. Rationale for Hub Services

Peoples Gas offers Hub service as a means to more efficiently utilize the existing Manlove and Mahomet pipeline assets and to provide customer benefits. Hub services provide customer benefits in three ways: (1) through credits to the Gas Charge (which is implemented in Rider 2 of the Tariff); (2) by extending the Manlove decline point (as defined below); and (3) by increasing market liquidity at the Chicago City-gate. Zack Reb., NS-PGL Ex. TZ-2.0, 66:1469-1473.

1. Credits to the Gas Charge

Peoples Gas has credited (or will be crediting following an order in its fiscal 2005 gas cost reconciliation case) to the Rider 2 Gas Charges over $20 million in 2005 and 2006 alone for the gross revenues from the Hub. In addition, as part of the resolution of Peoples Gas' fiscal years 2001-2004 Gas Charge case, the Commission determined that issues concerning the treatment of Hub revenues for those years were properly included in the refund that the Commission ordered. Additionally, Hub revenues are forecasted to reach $13 million in 2007. Zack Reb., NS-PGL Ex. TZ-2.0, 69:1541- 70:1551, Zack, Tr. at 516:9-10.

2. Extension of the Manlove Decline Point

The additional Hub volumes serve to extend the decline point. Extending the decline point of Manlove means extending the capability of the field to perform full peak withdrawal throughout the winter season. The operation of the Hub causes the injection of more gas into Manlove Field, which extends the field decline point, which, in turn, extends how long Manlove Field is useful for storage and capable of full peak withdrawal. Since all Hub volumes are contractually required to be withdrawn, they bring with them the benefit of the higher volumes without the risks associated with a warm winter. Puracchio Reb., NS-PGL Ex. TLP-2.0, 13:278-288. An examination of the actual results of the late season flow tests shows this to be undeniable. Roxar, Inc. prepared a report in July, 1999 that showed the decline point extending as working gas increased. NS-PGL Ex. TLP-2.9. Also, the 2003 and 2005 Connaugton Reports each contain a discussion of the extension of the decline point. Puracchio Reb., NS-PGL Ex. TLP-2.0, 14:290-292; NS-PGL Ex. TLP-1.1. So, the benefit to ratepayers comes in the form of access to the full daily peak withdrawal capability of Manlove Field longer into the winter season. At the same time, the risk of loss in future performance resulting from a significant amount of working gas being left in the reservoir following a warm winter, *i.e.*, the risk associated with not fully cycling the reservoir, is mitigated. Puracchio Reb., NS-PGL Ex. TLP-2.0, 13:278-288. This is so, because the gas injected as consequence of the Hub is contractually obligated to be removed during the withdrawal period, mitigating the risk of working gas left in the reservoir.

3. <u>Increasing Market Liquidity</u>

As to increasing market liquidity at the Chicago city gate, the Hub activity increases liquidity at Peoples Gas' city gate specifically and more generally in the Chicago area market. In particular, all the gas supporting Hub activity must come to one of Peoples Gas' city-gate locations to be a Hub transaction. This increases the amount of gas delivered to Peoples Gas on a daily basis. Therefore, the more gas brought to the Chicago city gate as a result of the operation of the Hub, the greater the benefit to all customers. This provides all customers access to a greater amount of gas than would otherwise be available if there was no Hub activity. Zack Reb., NS-PGL Ex. TZ-2.0, 70:1553-1558. Increasing market liquidity by increasing the supply of gas at the Chicago city gate creates downward pressure on gas prices.

D. Hub Costs And Revenues

1. Allocation Of Base Gas And Gas Charge Assets

Since the Hub came into existence, all of its expenses, including and consisting primarily of over $7 million of incremental compressor fuel costs have been borne by Peoples Gas. None of those costs were paid by Peoples Gas' customers. Zack Reb., NS-PGL Ex. TZ-2.0, 69:1538-1540. The Hub rate design included Manlove's base gas requirements and these costs were included in the cost of service study used to support the Hub filing before the FERC. *The Peoples Gas Light and Coke Company*, 82 FERC ¶ 62, 145 (1998); 82 FERC ¶ 61, 239 (1998); 86 FERC ¶ 61, 266 (1999). These costs were then used to develop the rates for Hub services under the Operating Statement. *Id.* at 68:1505-1507. The expansion of Manlove Field did not involve the use of Gas Charge assets or the use of assets in which costs were being recovered through base rates. All incremental expenses associated with the Hub were absorbed by Peoples Gas. Zack Reb., NS-PGL Ex. TZ-2.0, 67:1490-1496. Moreover, the storage expansion for the Hub began years after Peoples Gas' last rate case. The base rates approved in Peoples Gas' last rate case proceeding (ICC Docket No. 95-0032) therefore reflected a test year that was prior to the expansion of Manlove Field. *Id*. *See also* Grace, Reb., NS-PGL Ex. VG-2.0, 57:1261-1263. The record is devoid of any evidence that Peoples Gas has utilized any of the gas charge assets to subsidize Hub services.

2. Current Hub Costs And Expenses

a. Hub Expenses

All the costs and revenues associated with the Hub and the base rate assets that support the Hub are accounted for above the line. Expenses allocated to the Hub, consisting primarily of its incremental share of compressor fuel costs, have been just over $2 million per year. Zack

Reb., NS-PGL Ex. TZ-2.0, 70:1551-1552. Finally, the only incremental capital cost attributable to the Hub is cushion gas which is discussed herein.

b. Hub Revenues

The Hub is not and has never been a separate entity or separately identifiable group of facilities. It is part of the integrated Peoples Gas system. NS-PGL Ex. TZ-2.07 (Hub Revenues Compared To Estimate Of Hub Revenue Requirement) reflects an estimated revenue requirement for the Hub, along with the actual revenues generated. The calculation takes into account the incremental cushion gas provided by Mr. Puracchio as discussed above, as well as other operating expenses. In each of 2005 and 2006, Hub revenues have exceeded $10 million and they are expected to exceed that amount in 2007. Zack Reb., NS-PGL Ex. TZ-2.0, 70:1547-1551. The Hub clearly provides more benefits than costs. For example, in fiscal 2006 (test year), the Hub services exceeded this revenue requirement by $6.7 million (all credited to the Gas Charge). Clearly then, to eliminate the Hub and associated credits to the Gas Charge would be harmful to customers. Zack Reb., NS-PGL Ex. TZ-2.0, 71:1573-1577.

E. The Hub is a Benefit to Customers

The customer benefits provided by the Hub have exceeded, and are expected to continue to exceed, the costs of providing these services. Therefore, Peoples Gas should continue to provide Hub services for the benefit of its customers. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 43:945-948. When asked what a net benefit to ratepayers is as it pertains to the Hub, Staff Witness Dr. Rearden's response was, "[r]evenues of – either cost savings or revenues greater than costs" Dr. Rearden, Tr. at 674:1-4. Using Staff's simple definition, it is clear that Hub operations are a net benefit to the Peoples Gas system and its ratepayers.

F. **Staff's Improper Disallowance**

Staff's proposed disallowance of all costs associated with the Hub is improper. Dr. Rearden found that the Hub Revenues are estimated to be $10-$12 million per year. Rearden Dir., Staff Ex. 12.0, 22:473-474. Using his improper methodology, Dr. Rearden found that Hub costs per year were $13.3 million, made up of the capital costs of the supposed additional cushion gas plus operations and maintenance expense. Rearden Dir., Staff Ex. 12.0, 26:559-560 Since $13.3 million is more than $10-$12 million, he concluded that the Hub is imprudent. However, even accepting Dr. Rearden's numbers, which Peoples Gas does not, the revenue requirement should be reduced by $1.3 million to $3.3 million per year, the difference between the cost of $13.3 and the revenues of $10-$12 million dollars. Instead, Dr. Rearden proposes to eliminate <u>all the rate base and operations and maintenance expense associated with the Hub</u>, while leaving all the revenues in to reduce future gas costs. Rearden Dir., Staff Ex. 12.0, 30:617-636. If the Commission were to find the Hub imprudent, then the proper result would be to reduce the revenue requirement no more than $1.3 – $3.3 million. See Zack Reb., NS-PGL Ex. 2.0, 71:1584-1588.

G. **Hub Procedures**

Staff witness Mr. Lounsberry proposed that Peoples Gas develop procedures to document how Peoples Gas allocates Manlove storage capacity and how it ensures that ratepayers are not harmed by its allocation decisions. Lounsberry Reb., Staff Ex. 23.0, 14:266-276. He 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.* at 271-273 Peoples Gas' witness Mr. Zack testified that Peoples Gas would be willing to develop and document these procedures as proposed by Mr. Lounsberry, but that Peoples Gas proposed to provide this information to the Director of the Energy Division within 120 days of the Commission's final order in this proceeding given the number of rate case and other regulatory related matters to be addressed after the issuance of a final order. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 38:837-839.

While the Staff and Peoples Gas have reached agreement on the substance of its resolution, there remains a difference of 60 days time between the date by which Staff wants Peoples Gas to provide the requested information and the date by which Peoples Gas wants to be obligated to provide that information. Given the number of matters that Peoples Gas expects to have to address after the issuance of a final order in these proceedings, it believes more time is needed to prepare and document the appropriate procedures. Staff has offered no reason why the 60 day period is necessary. Therefore, Peoples Gas requests the Commission accept the 120 day timing proposed by Peoples Gas.

VI. WEATHER NORMALIZATION – AVERAGING PERIOD

The Utilities' gas deliveries, and therefore revenues, are highly dependent on weather. A comparison of the Utilities' sendout of gas with the key weather statistic reflecting use of gas for space heating, the "heating degree day" (or "HDD"), reveals a close correlation between cold temperatures and gas deliveries.[18] Similarly, over the course of a heating season, a colder winter results in more, and a warmer winter results in less, deliveries. One of the key factors in calculating the gas deliveries billing determinants is the projected level of heating degree days for a normal year during the period in which the rates are in effect. Weather normalization is a method of projecting expected gas deliveries based on normal weather for a utility's service area and building it into the rates. The Utilities' delivery service rates have a substantial volumetric

[18] The number of HDDs is the number of degrees Fahrenheit that the actual mean daily temperature is below 65 degrees Fahrenheit. Takle Dir., PGL Ex. EST-1.0, 7:139-151; Takle Dir., NS Ex. EST-1.0, 7:138-150.

component. Therefore, it is important to establish rates, based on the appropriate weather normalized gas deliveries, that will not result in revenues that would be materially higher or lower than those approved by the Commission. Grace Dir., PGL Ex. VG 1.0 2REV, 51:1122-1135; Grace Dir., NS Ex. VG 1.0 3REV, 45:984-997. No party disputes this, nor disputes the concept that weather normalization is appropriate for setting the Utilities' rates.[19]

The dispute raised by GCI centers on the calculation of the normal weather – the predicted number of heating degree days – that the Utilities can expect. In the Utilities' 1995 rate cases, the Commission approved weather normalization based on a thirty-year average of heating degree day statistics. In the most recent Nicor Gas rate case, ICC Docket No. 04-0779 at 57 (Order Sept. 20, 2005), the Commission approved the use of a ten-year average of heating degree day statistics for the Nicor Gas service territory directly adjacent to the territories of North Shore and Peoples Gas. The Utilities have proposed here that their heating degree day billing determinant be the average of the actual annual heating degree days experienced over the most recent ten calendar years prior to the filing of these rate cases. The Utilities proved, based on an analysis of all the weather statistics available, that compared to using an average of the past thirty years, an average of the past ten years will more accurately predict the heating degree days over the next several years, during which time the Utilities' proposed rates are expected to be in effect. The Utilities presented the testimony of Mr. Brian Marozas, an expert in statistics, who analyzed how predictive a ten-year average is compared to a thirty-year average. He found that the ten-year average is significantly more accurate in predicting future heating degree days.

[19] Note that Peoples Gas and North Shore have proposed two riders that would remove the weather component from the Utilities' rate recovery, essentially eliminating the importance of this issue. If either Rider VBA or Rider WNA is approved, the Utilities' rate recovery would no longer depend so significantly on the weather. See Section VII(B) of this Initial Brief, *infra*.

Marozas Dir., PGL Ex. BMM-1.0, 4:79 through Table 1; Marozas Dir., NS Ex. BMM-1.0 4:79 through Table 1.

Moreover, the Utilities proved that the winter climate in their service territories has begun to warm, and is expected to continue to do so over the next several years. A climate scientist, Prof. Eugene Takle, showed that Mr. Marozas' statistical results are consistent with the current scientific consensus on climate change. Takle Dir., PGL Ex. EST-1.0, 33:712-716; Takle Dir., NS Ex. EST-1.0, 33:711-715. The changing climate makes a shorter averaging period more accurate than a longer period, which has many years of data from the less relevant colder regime. Takle Dir., PGL Ex. EST-1.0, 32:701-702; Takle Dir., NS Ex. EST-1.0, 32:700-701; *see also* Marozas Dir., PGL Ex. BMM 1.0, 7:127-134, and Marozas Dir., NS Ex. BMM 1.0, 7:127-134. No party contested Professor Takle's conclusions.

Staff does not oppose the Utilities' proposed weather normalization methodology or numbers. One witness, GCI witness Mr. Glahn, was the sole witness to attempt to contest this issue. Mr. Glahn has experience with statistics, but he is not and does not hold himself out as a climate scientist. Mr. Glahn argued that the long term average calculated once per decade by the National Oceanic and Atmospheric Administration ("NOAA"), using thirty years of data, would be appropriate here. Glahn Dir., GCI Ex. 3.0, 40:1-4. The most recently available average is based on the years 1971-2000. Takle Dir., PGL Ex. EST-1.0, 28:623-626; Takle Dir., NS Ex. EST-1.0, 28:622-625. Despite his background in statistics, Mr. Glahn did not offer any statistical reasons why his metric would have better predictive power. Rather, he opined that using "more data" would necessarily be superior and would avoid effects of shorter term fluctuations. Glahn Reb., GCI Ex. 6.0, 20:499-500.

The Utilities' approach is demonstrably superior, both statistically and scientifically. First, Mr. Marozas' study, using all available data since the O'Hare weather station began collecting statistics, found that using a rolling ten-year average produces less error than a thirty-year average in predicting the next year out, as well as year two, three, four, and five. Marozas Sur., NS-PGL Ex. BMM-3.0, 2:22 – 3:46. That is important, because it is reasonable to assume that the rates set in this consolidated docket will be in effect for one to five years.[20] Second, the warming climate counsels against using data from thirty or more years ago that is not representative of today's climate. Takle Dir., PGL Ex. EST-1.0, 32:700-711; Takle Dir., NS Ex. EST-1.0, 32:699-710. Third, the NOAA long-term thirty-year average is a particularly poor predictor. As described by Professor Takle, a group of Illinois climatologists[21] studied averaging periods several years ago and concluded that the NOAA thirty-year average was one of the worst predictors of any averaging method they tested. Takle Dir., PGL Ex. EST-1.0, 30:651-655; Takle Dir., NS Ex. EST-1.0, 30:650-654; Takle Reb., NS-PGL Ex. EST-2.0, 5:103 – 6:115. Professor Takle also noted that, based on his review of an upcoming article accepted for publication in a scholarly journal, at least some NOAA scientists now take the position that the old thirty-year normal is no longer appropriate. Takle Sur., PGL/NS Ex. EST-3.0, 2:38 - 3:53.

Absent Rider VBA or Rider WNA, the effect of using an appropriate weather normalization period is essential if Peoples Gas' and North Shore' rates are to be fair. The most recent ten-year average of heating degree days is 6,044 per year. Marozas Dir., PGL Ex. BMM-

[20] The Utilities originally proposed to amortize rate cases expenses over three years, but Staff and GCI proposed, and the Utilities, in order to narrow the contested issues, accepted a five year period. *See* Section III(B)(5)(i) of this Initial Brief, *supra*.

[21] The report discussed by Professor Takle is Easterling, W. E., J. R. Angel, and S. A. Kirsch, 1990: The Appropriate Use Of Climatic Information In Illinois Natural-Gas Utility Weather-Normalization Techniques. Illinois Water Survey Report of Investigation ISWS/RI-112/90, discussed at pages 28-31 of Takle Dir., PGL Ex. EST-1.0 and Takle Dir., NS Ex. EST-1.0.

1.0, 7:Table 2; Marozas Dir., NS Ex. BMM-1.0, 7:Table 2. The average of the most recent thirty years is 6,401 HDDs per year, and the NOAA thirty-year average (1971-2000) is 6,498. Takle Dir., PGL Ex. EST-1.0, 28:606-612; Takle Dir., NS Ex. EST-1.0, 28:605-611. Setting the gas deliveries based on the higher 6,401 or 6,498 HDD level will cause the Utilities' rates for recovering the allowed base rate revenue requirement to be set too low for the number of heating degree days that the record clearly shows the Utilities' service territories are likely to experience. Thus, when the weather is, in fact, warmer than the 6,401 HDD per year level, as it likely will be, setting the normalization number incorrectly at 6,401 HDD will prevent the Utilities from recovering the revenue amounts authorized by the Commission. Grace Reb., PGL/NS Ex. 2.0, 25:524-539.

Accordingly, based on the evidence, the Commission should approve the Utilities' ten-year average (6,044 HDD) for purposes of calculating the proper billing determinants.

VII. NEW RIDERS

A. Overview

Peoples Gas and North Shore have demonstrated, and no party has introduced evidence to rebut, that the business conditions described in the Summary section and Appendix A of this Initial Brief present considerable challenges to their ability to achieve reasonable financial performance and stability, *see, e.g.,* Feingold Dir., PGL Ex. RAF-1.0, 2:40-41, 6:121 - 7:128; Feingold Dir., NS Ex. RAF-1.0, 2:36-37, 5:113 - 6:123, and that the business challenges have considerably impcted customer gas sales, s*ee, e.g.,* PGL Exs. LTB-1.2, LTB-1.3. Indeed, those business challenges have had a combined effect of introducing elements of considerable and recurring variability, unpredictability, and uncontrollability to the Utilities' cost of delivery service and the gas usage factors used to set its base rates to recover such costs. *See, e.g.,* Feingold Dir., PGL Ex. RAF-1.0, 8:158-162; Feingold Dir., NS Ex. RAF-1.0, 7:152-156.

The Commission has historically been responsive to changing business realities and has not hesitated to apply various rate methods to achieve its policy objectives, including the implementation of trackers. Indeed, the Commission has consistently employed rate tracking mechanisms in the form of riders, whether statutorily authorized, *e.g.*, 220 ILCS 5/9-220, or implemented by the Commission on its own initiative. *See Re Investigation Concerning Issues Related to Coal Tar Cleanup Expenditures*, 137 P.U.R. 4th 272, 1992 WL 333219 (Ill. C.C. Sept. 30, 1992) (Docket No. 91-0080 *et al.*). The Commission has made it abundantly clear that rate tracking is an acceptable means of utility cost recovery and the Courts have upheld this view. *City of Chicago v. ICC*, 13 Ill.2d 607 (1958). In *City of Chicago*, the Court held:

> We conclude that the Public Utilities Act of Illinois vested in the Commission the power to authorize an automatic adjustment clause to be filed in a rate schedule in the proper case.

Id. at 780. Given the Commission's consistent application of trackers when justified, it cannot seriously be argued that such mechanisms are inappropriate or unreasonable.

This Commission has consistently acknowledged the usefulness of rider mechanisms when costs vary widely and there are difficulties in making forecasts of the scope, costs and timing of eligible costs. *See, e.g., Central Illinois Light Company* ("*CILCO*"), 124 P.U.R. 4th 498, 1991 WL 501759 (Ill. C.C. Aug. 2, 1991) (Docket No. 90-0127). Thus, the Utilities' proposals to implement rider mechanisms to recover various costs in these proceedings that are unpredictable or outside the control of the Utilities are reasonable and well within the parameters of the Commission's lawful authority and policy. Arguments that rate riders are "piecemeal", "nontraditional" or otherwise are problematic, as urged by witnesses Messrs. Lazare and Brosch**,** Staff Ex. 8.0, 9:201-205; GCI Ex. 1.0, 11:15-21, are simply unavailing in the face of the long standing and judicially sanctioned use of rate trackers in Illinois.

Furthermore, Mr. Feingold has established that there is a growing recognition in the gas utility industry that certain base rate components that exhibit volatile or unpredictable characteristics should be recovered through automatic rate adjustment mechanisms, rather than through fixed charges. Mr. Feingold identified some of these rate components as uncollectible expenses, infrastructure improvement costs, government mandated safety costs, public improvement project costs, property taxes, pension expenses, and environmental costs. Feingold Dir., PGL Ex. RAF-1.0, 11:223-228; NS Ex. RAF-1.0, 10:218-225. The Utilities in these proceedings have identified uncollectible expenses, energy efficiency program costs, and infrastructure replacement costs as the type of costs that should be recovered through automatic rate adjustments. In addition, the Utilities have proposed a "decoupling" mechanism (Rider VBA) to address incentives in the current rate structure for the Utilities to increase gas sales and not to support conservation. Hence, the Utilities have proposed four (4) new rate riders which would provide the rate flexibility necessary to address the realities in today's business environment. These mechanisms, Rider VBA (or, as an alternative, Rider WNA), Rider UBA, Rider EEP and Rider ICR (applicable only to Peoples Gas), will each in turn be discussed below.

B. Rider VBA and Rider WNA

Rider VBA is a rate mechanism designed to provide the Utilities with a measure of assurance of recovery of the portion of the revenue requirement approved by the Commission in these proceedings that is to be recovered through volumetric charges. This is commonly known as a decoupling mechanism. The purpose of decoupling is to remove both the incentive utilities have to increase sales and the disincentive utilities have to encourage energy efficiency for its customers. The Utilities have proposed Rider VBA based on their recognition of current environmental and economic realities and the impact of those factors on the regulatory process and the utility business.

Among these new realities is that utilities can no longer expect that increased sales are a viable business goal in the face of declining use and the rising cost of natural gas. Moreover, current concerns over global warming and dependence on energy imports have prompted utilities and other policy makers to reevaluate existing regulatory models and express support for decoupling. As detailed below, this has resulted in an ever increasing number of utility proposals and regulatory decisions to implement decoupling and similar type rate policies. Rider VBA is an opportunity for the Commission to participate in this growing acknowledgement of the need for rate setting bodies to address issues of global warming impacts and energy independence and their impact on energy utilization, conservation and utility financial stability. Rider VBA serves these critical goals by providing the Utilities with a measure of financial stability that will enable them to participate enthusiastically in promoting energy conservation and efficiency without the fear of undermining their business interests.

1. Rider VBA Mechanics

Specifically, Rider VBA is a mechanism which will adjust the rates of the Utilities on a monthly basis for the effects of weather and usage changes, such as those caused by conservation, on the Utilities' rates. Rider VBA will be applicable to the Utilities' customers under Service Classification ("S.C.") Nos. 1N, 1H and 2. A separate adjustment would be determined for each applicable service classification. The Rider VBA adjustment would be computed on a monthly basis by taking the difference between a baseline rate case distribution margin per customer (Rate Case Margin) factor against actual distribution margin (Actual Margin) in a given month. The Rate Case Margin for each month would be based on the

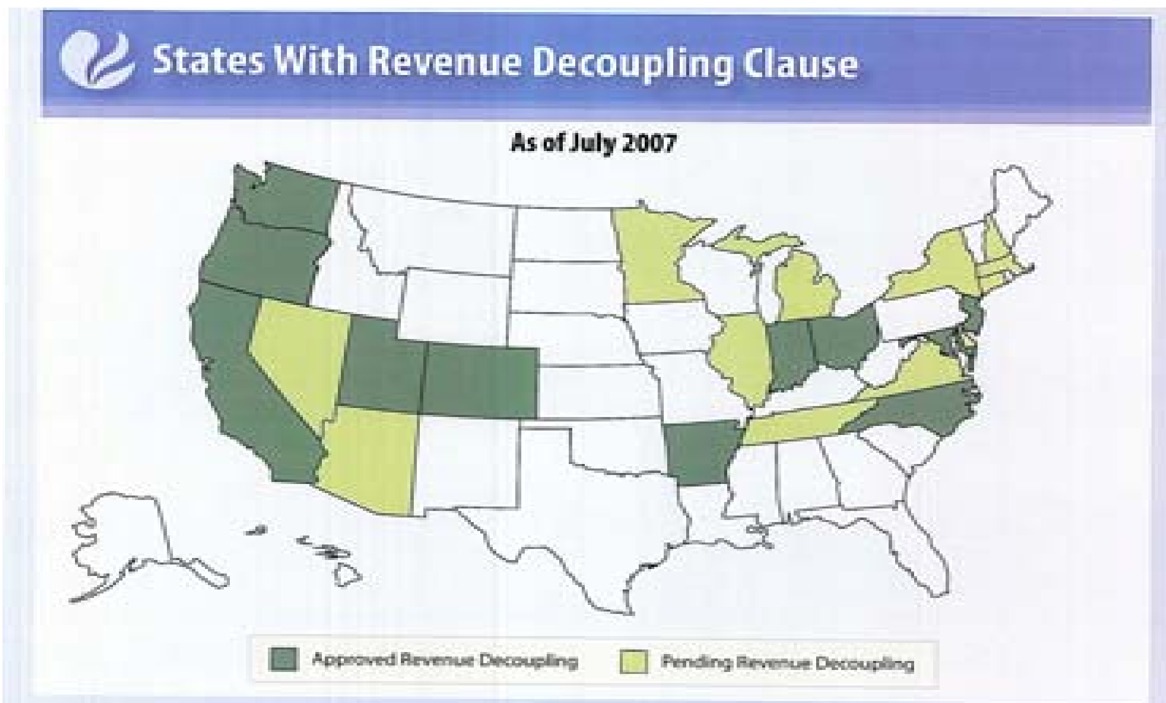
Commission approved distribution margin for each month divided by the number of Commission approved customers (Rate Case Customers) for the same month. The difference will be multiplied by the Rate Case Customers and divided by the number of therms estimated for the effective month of the adjustment, yielding the monthly per therm adjustment. The actual adjustment will be computed and applied to customers' bills each month using actual and rate case data from the second month prior to the effective month of the adjustment to be charged. Grace Dir., PGL Ex. VG-1.0 2REV, 47:1038-1052; NS Ex. VG-1.0 3REV, 42:928 - 43:942.

A Base Customer Margin per customer and average number of customers level for each applicable rate classification will be established and a separate adjustment will be computed for each service classification. The monthly adjustments will be established by calculating the difference between the Base Customer Margin and the Actual Margin per customer for the applicable month. That difference will be multiplied by the Rate Case Customers and divided by the number of therms estimated for the effective month of the adjustment, yielding a monthly therm adjustment. *Id.* at 47:1046-1052 and 43:936-942, respectively.

Rider VBA would be subject to an annual reconciliation with adjustments to insure that the implementation of Rider VBA is in compliance with tariff provisions and would be filed on the 20th of the month to permit Staff review prior to the effective date of the adjustment. Annual internal audits would be conducted by the Companies. Grace Dir., PGL Ex. VG-1.0 2REV, 48:1059-1062; Grace Dir., NS Ex. VG-1.0 3REV, 43:949-952; Hathhorn Dir., Staff Ex. 1.0, 28:581-587.

2. <u>Rider VBA Type Decoupling Is Being Adopted Elsewhere</u>

Decoupling mechanisms and their rate tracking features have been widely adopted by state regulatory commissions over the past several years. Decoupling mechanisms have been adopted in at least 9 states. Feingold Sur., NS-PGL Ex. RAF-3.0, 5:96-99. Decoupling mechanisms are becoming increasingly more common across the country in response to the significant environmental and national interest considerations discussed earlier, as well as the business challenges faced by natural gas utilities. Exhibit NS-PGL RAF-2.3 below shows the increasingly widespread adoption of decoupling mechanisms across the U.S. While no decoupling mechanisms have been adopted in the state of Illinois, the policy challenges and business justification which are the predicate for decoupling mechanisms certainly exist.



3. **Benefits of Decoupling**

The record demonstrates that Rider VBA would effectively address environmental and national interests objectives which should be key considerations in current rate regulatory decisions. Rider VBA does so by enhancing the promotion of energy conservation and efficiency measures by the Utilities through the decoupling feature. The decoupling occurs by removing the effects of weather and customer usage from the determination of how much of the utility's revenue requirement is recovered. The throughput on the system in a given period is decoupled, or separated, from the amount of the recovery. The Utilities, then, have no incentive to sell any particular level of gas volumes because the revenue requirement is met with less emphasis on the amount of gas sold or transported. Thus, Rider VBA would remove the disincentive that the Utilities have to promote energy conservation and efficiency programs for its customers. By breaking the link (decoupling) between the Utilities' earnings and sales, Rider VBA would eliminate the Utilities' "Throughput Incentive". Feingold Dir., PGL Ex. RAF-1.0, 23:454-468; NS Ex. RAF-1.0, 21:456-470.

The Throughput Incentive, and its conflict with the goal of energy efficiency promotion, has been established as a sound basis for implementing revenue decoupling. *Re Northwest Natural Gas Co.*, 245 P.U.R. 4th 165, 2005 WL 2222265 (Or. P.U.C. Aug. 25, 2005) (Docket No. 05-934). For example, in evaluating the revenue decoupling mechanism of NW Natural, Christensen Associates Energy Consulting, LLC ("Christensen") performed a study which addressed certain questions from the Oregon Public Utility Commission that are pertinent here. Christensen concluded that NW Natural's revenue decoupling mechanism:

1. Did not shift risk to customers;
2. Did not create negative incentives toward customer service;
3. Reduced the Utility's disincentive towards energy efficiency; and
4. Improved the Utility's ability to recover its fixed costs.

NS-PGL Ex. RAF-2.0, 46:923-932.

Another method of reducing the Throughput Incentive, would be to lower the volumetric (or distribution) charge by increasing the fixed (or customer) charge. The Utilities have painstakingly demonstrated the increases in their customer charges are warranted. However, if

Rider VBA is adopted, the need to increase the customer charges to the levels proposed by the Utilities would be somewhat mitigated. *See* Grace Dir., PGL Ex. VG-1.0 2REV, 18:392-398; Grace Dir., NS Ex. VG-1.0 3REV, 16:339-344; Feingold Reb., NS-PGL Ex. RAF-2.0, 18:345-360.

Other benefits will attend Rider VBA. Under Rider VBA, the Utilities would recover the portion of the revenue requirement established in this case that is allocated to volumetric charges, no more, no less. When weather is colder than the weather on which rates have been set, customers would pay less than they would otherwise pay without Rider VBA for the Utilities' fixed costs of delivery service and the Utilities would not over-recover margin revenues. Conversely, when weather is warmer than the weather on which rates have been set, customers would pay slightly more than they would otherwise pay without Rider VBA and the Utilities would not under-recover margin revenues. Furthermore, Rider VBA would incorporate realistic gas volume levels for computing the Utilities' unit delivery rates by utilizing actual volume experience in the monthly rate adjustments. Finally, Rider VBA would be a more effective ratemaking method to address margin volatility and would enable the Utilities to promote energy conservation and efficiency programs without the continual threat of margin losses due to declining gas sales per customer. Feingold Reb., NS-PGL Ex. RF-2.0, 45:902-918.

Rider VBA is also an appropriate mechanism to address the impact of the energy efficiency program proposed by the Companies. Should the Commission approve the program, sales will decrease compared to the levels that have been proposed in this rate case. All other things being equal, and absent Rider VBA, the Companies will then not be able to recover the revenue requirement established in this rate case. So, without Rider VBA, the Companies will be penalized for proposing the energy efficiency program.

The foregoing described benefits of Rider VBA have been recognized in several decoupling decisions and would be no less present here. *Re New Jersey Natural Gas Co.*, 2006 WL 3623341 (N.J.B.P.U. Sept. 29, 2006) (Docket No. GR060604-15); *Re Southwest Gas Corp.*, 232 P.U.R. 4th 353, 2004 WL 673088 (Cal. P.U.C. Mar. 16, 2004) (Application No. 02-02-012); *Re Conservation Enabling Tariff Adjustment Option and Accounting Orders,* 2007 WL 1616219 (Utah P.S.C. Jan. 16, 2007) (Docket No. 05-057-T01); *Re Cascade Natural Gas Corp.* (WA U.T.C. Aug. 16th, 2007) (Docket No. UG-060256); *Re Indiana Gas Co., Inc.*, 2006 WL 4483149 (Ind. U.R.C. Dec. 1, 2006) (Case No. 42943). See also Feingold Reb., NS-PGL Ex. RF-2.0, 46:923-935. Furthermore, Rider VBA will not entail any shift of risk to customers because it does not guarantee any specific financial performance. To the extent normal weather is assumed over time, Rider VBA's adjustment to reflect weather represents no risk shifting. Similarly, risks attendant to throughput are evened out by the upward and downward adjustments for warmer and colder weather, respectively. Feingold Reb., NS-PGL Ex. RF-2.0, 50:1017-51:1032.

4. <u>Concerns Regarding Decoupling</u>

While certain parties have introduced generalized arguments that the Utilities' actions have no bearing on customer conservation decisions, the existence of the Throughput Incentive cannot be denied, as discussed above. The only other arguments which have been put forth in opposition to Rider VBA are that it departs from "traditional ratemaking" and would introduce a measure of complexity and administrative burden for regulators. Such arguments are meritless and have been put forth solely in an effort to maintain the *status quo*. It cannot be disputed that more and more state commissions are approving revenue decoupling mechanisms similar to Rider VBA in recognition that such mechanisms have identifiable benefits for ratepayers and utilities. The state of New York has even seen fit to recommend that all utilities in the state propose decoupling measures to address today's business realities. *Re Investigation of Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, et al.*, 256 P.U.R. 4th 477, 2007 WL 1185703 (N.Y.P.S.C. Apr. 20th, 2007) (Docket No. 03-E-0604).

5. Rider VBA Should Be Approved

It cannot be disputed that decoupling in general and Rider VBA itself are conceptually sound and based upon widely accepted utility ratemaking approaches. While certainly some decoupling mechanisms have not been approved, the trend is clearly toward broader approval. Further the Utilities' financial under-performance over the recent past is clearly indicative of acute business challenges that give rise to the need for new ratemaking approaches because traditional ratemaking approaches do not address current business realities. A utility's financial results cannot be ignored or downplayed simply to preserve the *status quo*. No amount of singing the praises of traditional ratemaking and the purported symmetry that has accompanied it changes the stark reality of the financial under-performance which attends traditional ratemaking in the business environment that the Utilities have experienced in the last several years. Opponents of Rider VBA are simply ignoring the Utilities' financial under-performance and offering no affirmative recommendations as to how such challenges could be addressed. Rather, the opponents are simply waving the flag of tradition and making exaggerated claims about complexity and burden. The fact of the matter is that Rider VBA is a fair and balanced means to provide significant benefits to the Companies and ratepayers and is straight forward to implement and simple to administer. Feingold Reb., NS-PGL Ex. RAF-2.0, 44:899 - 45:918.

6. Rider WNA

While the Utilities have thoroughly established in the record the need for Rider VBA, the an alternative mechanism, a weather normalization adjustment (Rider WNA), could achieve certain of their goals and the goals of decoupling. While Rider VBA is the Utilities' preferred methodology since it addresses the inappropriate incentives under the current regulatory regime, the Utilities have offered, in the alternative, a Rider WNA mechanism to address solely the impact of weather. Borgard Reb., NS-PGL Ex. LTB-2.0, 12:272-280. Proposed Rider WNA is conceptually equivalent to the weather normalization adjustment mechanisms noted by Mr. Feingold when he discussed the gas distribution industry's ratemaking responses to the under-recovery of fixed costs. Feingold Dir., PGL Ex. RAF-1.0, 21:422-425; Feingold Dir., NS Ex. RAF 1.0, 19:422-425.

Rider WNA represents an alternative ratemaking approach that has the following advantages over traditional ratemaking:

1. The Companies' gas rates are designed on the basis of the expected volume of gas to be sold for these services under normal weather conditions. This means that the Companies will recover their annual fixed costs of providing delivery service only if the level of sales volumes upon which their rate designs are predicated is achieved. That sales level is based upon the Companies' weather-normalized gas volumes. Rider WNA will ensure that the level of sales volumes established to recover their fixed costs is always reflected in the monthly billings to their customers.

2. Deviations from normal weather can result in either over or under recovery of the Companies' annual margin revenues when actual weather experienced is colder or warmer than normal, respectively. Such over or under recoveries will produce erratic financial results that would cause the financial community not to look as favorably at a utility's financial position relative to the financial positions of other utilities with weather normalization clauses, all other things being equal.

3. Rider WNA will directly address the ever-increasing issue of volatility in customers' gas bills – this ratemaking mechanism will provide more stable annual bill amounts and mitigate volatility in customers' monthly gas bills. Customers will be better able to budget for and pay their monthly bills.

4. The consumer is inclined to look with disfavor on the utility whenever the bill increases greatly during periods of high gas consumption and to overlook those occasions when the bill is lower. As described above, Rider WNA will directly address this issue by providing more stable annual bill amounts and mitigation of volatility in monthly gas bills.

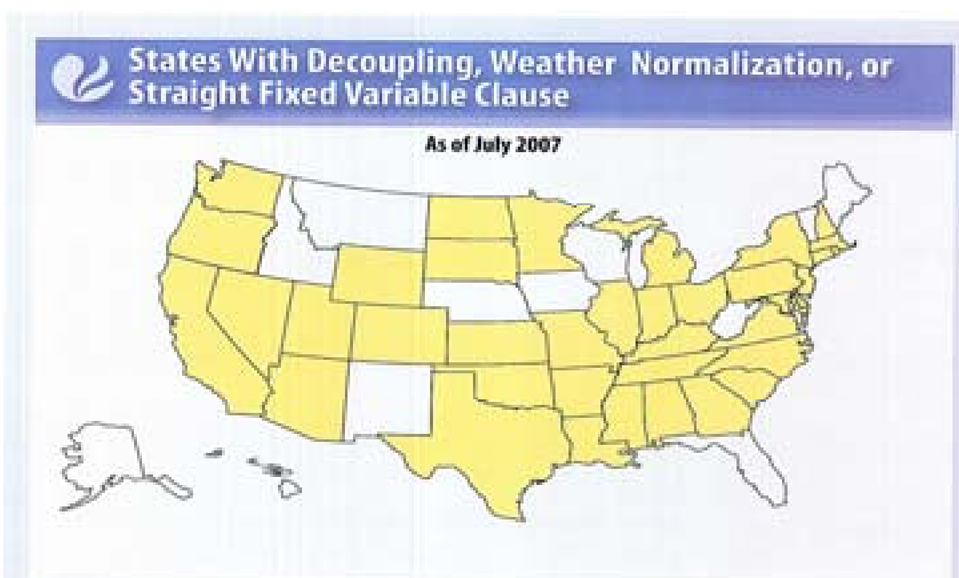
5. Rider WNA can send more accurate price signals to the Companies' customers compared to the current ratemaking method because it will stabilize the portion of a customer's bill related to the recovery of fixed costs, while still recovering the variable gas costs on a volumetric basis.

Feingold Reb., NS-PGL Ex. RAF-2.0, 60:1226-1251.

The Utilities' proposed Rider WNA would consist of a monthly adjustment to gas bills. Rider WNA would establish service class specific weather adjustments for each of S.C. Nos. 1N, 1H and 2 (heating customers only). These adjustments would be determined by using service class specific Heat and Base Load Factors and Normal and Actual Heating Degree Days to determine weather adjustment volumes. The weather adjustment volumes would be multiplied by the service class specific Base Rates to determine the WNA. The adjustments would be determined for the months of October through May only with an annual report to be submitted to the Commission by September 30 of each year. The Heat and Base Load Factors, Normal Heating Degree Days and Base Rates would be established in this proceeding. The Companies' Base Rates would be the end block rates approved by the Commission for S.C. Nos. 1H and 2. Grace, Reb., NS-PGL Ex. VG 2.0, 55:1219-57:1247. The Companies' Base Rate for S.C. No. 1N would depend upon the rate structure approved by the Commission in this proceeding and would be either a flat rate or an end block rate. Grace, Reb., NSPGL Ex. VG 2.0, 55:1219-57:1247. Grace, Sur. NS-PGL Ex. VG 3.0, 28:592-29:611.

No party has contended that a WNA is not a valid and widely accepted means of addressing weather in rates. Indeed, one of the principal opponents of Rider VBA, Mr. Brosch, admits that WNA's have been widely adopted and are a reasonable means of addressing weather in rates. *See* Brosch, Tr. at 1522:4-16; Brosch Dir., GCI Ex. 1.0, 41:13-15. The Utilities have also shown that the tangible benefits from implementing Rider WNA are: (1) it will reduce bill variability due to weather in the bill for the month in which the variation occurs; (2) the adjustment is consistent with the rate class approach that is used to normalize sales volumes to derive the Utilities' delivery service charges; and (3) the individual customers retain the savings due to their own energy conservation practices. Feingold Reb., NS-PGL Ex. RAF 2.0, 65:1329 – 66:1335. Since it does not require a deferral mechanism, Rider WNA could also smooth out monthly and seasonal cash flows. Feingold Reb., NS-PGL Ex. RAF-2.0, 65:1331 - 66:1341. WNA's have been adopted in at least 25 states representing 44 utility service areas, and the trend is toward greater utilization of those mechanisms. *See id.*, 66:1345-1350; NS-PGL Ex. RAF-2.7.

Mr. Feingold has noted that another means of addressing the business challenges associated with fixed cost recovery is by adoption of a straight fixed variable ("SFV") design which he indicates has been adopted in four states. Feingold Reb., NS-PGL Ex. RAF-2.0, 14:67 - 15:288. Thus, combining the states which have adopted SFV rate design with those which have adopted decoupling mechanisms or WNA mechanisms presents a very compelling picture, indeed. As illustrated below, as of July 2007, revenue decoupling, SFV or WNA proposals are pending in 38 states. Such "non-traditional" rate mechanisms have actually been adopted in 36 states. NS-PGL Exs. RAF-2.3, RAF-2.7.



This Commission would not, therefore, be breaking new ground by approving a Rider VBA or Rider WNA in these proceedings. In fact, Illinois would be simply catching up with the trend among the states and recognizing that conservation and national energy independence imperatives, as well as today's business environment have created unique circumstances that require different policy making decisions than have been required in the past.

Peoples Gas and North Shore have proposed specific ratemaking models to address indisputable business and policy challenges. Those methods, Rider VBA and Rider WNA, are reasonable and measured approaches to meeting the demonstrated challenges. While parties have been critical of the Utilities' proposals in general and identified arguable implementation issues, no party has remotely demonstrated that Rider VBA and Rider WNA are unreasonable *per se*. Moreover, no other party has offered a comprehensive or other viable approach to resolving the challenges presented.

C. Rider ICR[22]

1. Overview

Currently, Peoples Gas' system includes nearly 2,000 miles of cast iron and ductile iron ("CI/DI") mains. This amount represents a considerable portion, approximately half, of the Peoples Gas system mains. Peoples Gas has been steadily replacing this main for many years. The Company is proposing to accelerate the pace at which CI/DI main is replaced, provided that it is allowed to timely recover the costs of this accelerated capital investment. Peoples Gas' proposed Rider ICR is a mechanism to recover the recurring capital-related costs of its proposed

[22] Peoples Gas' original proposal was termed Rider ICR. While the Company believes its original proposal was a sound proposal, this brief will focus on the Rider ICR as modified by Staff's recommendation. In addition, Staff has suggested changing the name of Rider ICR to Rider QIP. Rider QIP is the term used for the rider mechanism under Part 656 of the ICC's rules, a similar, but not identical, mechanism to the one proposed and modified here. While the Company believes the term "Rider ICR" is consistent with the history of the testimony and appropriately distinguishes Rider ICR from Rider QIP, the Company would not oppose renaming its Rider ICR mechanism and denominate it "Rider QIP".

acceleration of CI/DI main replacement on its system. Rider ICR enables Peoples Gas to take advantage of more opportunities as they arise to replace vintage portions of its gas system without the negative financial consequences such business actions would create under traditional ratemaking methods. Feingold Dir., PGL Ex. RAF-1.0, 44:876-882.

Accelerating CI/DI main replacement coupled with Rider ICR allows the Company to capture two key benefits for Peoples Gas' customers and the City of Chicago. The first is more expeditious replacement and modernization of Peoples Gas' distribution system, a key element of the City of Chicago's infrastructure. Second, in modernizing its distribution infrastructure, Peoples Gas would obtain savings for ratepayers as a result of accelerating CI/DI main replacement and being able to avail itself of unknown and unforeseen main replacement opportunities.

Staff, through its witnesses Mr. Lazare and Ms. Hathhorn, and GCI, through its witness Mr. Brosch, argue against some or all aspects of the ICR mechanism. However, no one has challenged the acceleration concept, *per se*. Rather, concerns have been raised as to the certainty or amount of savings to be achieved through acceleration. Staff witness Ms. Hathhorn, while not supporting Rider ICR, has offered a framework for its operation if the Commission were to approve Rider ICR. In response to the concerns raised by witnesses Ms. Hathhorn and Mr. Brosch, Peoples Gas has significantly modified its approach to Rider ICR, as it was originally proposed. While Peoples Gas has modified its Rider ICR to accept many of the changes offered by Staff and Mr. Brosch, the Company has not accepted every proposed revision. Peoples Gas believes, however, that its Rider ICR proposal, as it has been modified to incorporate the reasonable proposals of Staff and intervenors, represents a sound and just means of balancing the interests of all stakeholders in accelerating the modernization of the gas utility infrastructure in Chicago.

2. Benefits of the Accelerated Program

The ability to accelerate the time frame in which the CI/DI main will be replaced will result in considerable benefits to the system, including certain financial benefits. In addition to the benefits of significantly contributing to the improvement and modernization of the overall infrastructure of the City of Chicago, acceleration of CI/DI main will provide several other benefits. These include: (1) financial benefits associated with expending current dollars for a major monetary undertaking; (2) benefits relating to the replacement of Peoples Gas' low pressure system; and (3) benefits afforded by the opportunity to respond to the dynamic development in the City of Chicago. Schott Dir., PGL Ex. JFS-1.0, 6:121-125.

a. Financial Benefits

Peoples Gas has indicated that the total cost of replacing the CI/DI main on its system could be expected to be over $1 billion. Schott Dir., PGL Ex. JFS-1.0, 9:200-10:205. Any time main replacement requires an expenditure of over $1 billion, when that $1 billion is to be spent in a significantly shorter time frame, considerably greater economies of scale would result. *Id.* at 205-209. Savings also occur by accelerating main replacement and avoiding the cost of maintenance incident to main leaks that would otherwise occur absent acceleration. Savings between $180,000 and $300,000 per year in main leaks could be achieved. Schott, Tr. at 1551:8-17. *See also* NS-PGL Ex. JFS-3.2. Cost savings could also be achieved in street repair costs associated with main repair and replacement as more projects could be coordinated with the City, resulting in the sharing of these costs between the City and the customers. As discussed below in detail, meters presently located inside customers' homes would be moved to the exterior of the house. The benefits of moving meters outside could also generate financial savings. Schott Dir., PGL Ex. JFS-1.0, 9:186-187.

b. Benefits Relating to the Replacement of Peoples Gas' Low Pressure System

There are several operational benefits that result from the replacement of Peoples Gas' low pressure system. These benefits involve the relocation of meters, the replacement of regulator vaults and the reduction in the occurrence of certain service outages. It has been demonstrated that meters presently located inside homes could be moved to the building exteriors. Such meter relocation will avoid in the future the difficulties and customer inconveniences associated with the scheduling of inside inspections. Schott Dir., PGL Ex. JFS-1.0, 7:139-150; Schott, Tr. at 1551:8-17. The relocation of meters would also assist in the completion the installation of automatic meter reading devices. Additionally, the relocation would make it easier to detect meter tampering. Schott Dir., PGL Ex. JFS-1.0, 9:185-189.

The replacement of the low pressure system will also entail eliminating low pressure regulator vaults on the system and thereby the attendant maintenance, operations and reliability issues associated with them. Doerk Dir., PGL Ex. ED-1.0, 18:370-390. An entire class of low pressure regulating stations could be phased out. *Id.*

Elimination of the low pressure system will also reduce the occurrence of outages due to ground water infiltration because low pressure systems are particularly susceptible to outages caused by water seepage. Doerk Dir., PGL Ex. ED-1.0, 18:377-383. In general, high pressure systems, which replace the low pressure systems, are inherently more reliable than the older vintage low pressure systems. *Id*. at 375-377. Furthermore, modern high pressure gas systems utilize smaller diameter piping than old low pressure systems. Smaller piping allows for more cost effective replacement of comparable capacity low pressure systems.

c. **Benefits Afforded by the Opportunity to Respond <u>to the Dynamic Development in the City of Chicago</u>**

The City of Chicago is a very dynamic city where development and change occur frequently and often unexpectedly. Development occurs in an unpredictable fashion and in surprising ways that defy convention and planning, yet presents considerable opportunities for CI/DI main replacement. The ability to react to and work with these development efforts across the City provides Peoples Gas the opportunity to accelerate main replacement and to take advantage of joint construction efforts. Such joint efforts would reduce the cost that Peoples Gas would otherwise pay for the replacement of the CI/DI mains. Schott Dir., PGL Ex. JFS-1.0, 10:224 - 11:242. Acceleration of the CI/DI main replacement is simply a means by which Peoples Gas can avail itself of greater opportunities to cooperate with the City of Chicago, as well as other entities, who are undertaking projects that might permit greater CI/DI main replacement opportunities at lower costs than would otherwise occur. Schott Reb., NS-PGL Ex. JFS-2.0, 8:160 - 9:164.

3. <u>The ICR Mechanism</u>

Only Rider ICR adequately addresses the financial impact of the magnitude and uncertainty that accelerating CI/DI main replacement would entail on an ongoing basis. Only Rider ICR would allow Peoples Gas the financial wherewithal to respond to external forces and events and thereby manage the unpredictability and uniqueness of the opportunities which acceleration would afford. Schott Dir., PGL Ex. JFS-1.0, 13:281-287.

Acceleration of CI/DI replacement would give Peoples Gas the opportunity to achieve greater savings and could actually be the least costly alternative for the replacement of CI/DI main. Rider ICR is the most suitable cost recovery mechanism, because it resolves difficulties and uncertainties surrounding projecting the precise level of infrastructure costs that might be expended. Schott Reb., NS-PGL Ex. JFS-2.0, 10:195-202. A rider resolves issues surrounding the timing of when costs are incurred and when they are recovered, reconciling costs and recoveries, as well as issues surrounding forecasting.

4. Rider ICR Modifications

As earlier noted, Peoples Gas has accepted several recommendations of the parties to modify its original Rider ICR proposal. Most notably, Ms. Hathhorn testified that should the Commission decide that rider recovery of plant costs is appropriate, Part 656 should be used as a template. The Company has agreed to adopt several of Staff's modifications recommended by Ms. Hathhorn: (1) a criterion that only the costs of 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 of prudently-incurred costs. Schott Reb., NS-PGL Ex. JFS-2.0, 4:64-68.

People Gas has agreed, as part of the modification of its proposal in the course of the proceeding, to include the opportunity to evaluate prudence in the annual reconciliation procedure that is attendant to the Rider ICR proposal. This will offer Staff and other interested parties the ability to more sharply focus any appropriate evaluation of Peoples Gas' capital expenditures for CI/DI replacement. This ability might not be as clear in the context of a general rate case where all capital expenditures would be at issue. However, Peoples Gas opposes Staff Witness Hathhorn's proposal to include a rate of return credit in the proposed Rider ICR which will be discussed in more detail below. Schott Sur., NS-PGL Ex. JFS-3.0 2 REV, 3:45-46.

Staff's and intervenors' opposition to Rider ICR appears to be centered around: (1) whether there is a need for the accelerated approach when the existing replacement program appears adequate, (2) whether Rider ICR meets purported tests for rate tracking riders; and

(3) whether accelerating CI/DI replacement through Rider ICR would amount to an extraordinary price for the replacement and modernization of Peoples Gas' infrastructure; and (4) Peoples Gas' position not to include a rate of return credit in Rider ICR.

a. <u>Need for the Accelerated Program</u>

Certain parties have argued that the Company has managed to replace CI/DI main at a safe and reasonable pace since the main replacement program began in 1981 and that therefore, an accelerated approach may not be necessary. What the argument fails to acknowledge, however, is that Rider ICR is being proposed to further accelerate CI/DI main replacement to reduce the costs of the main replacements, while allowing Peoples Gas the ability to respond to unknown, unforeseen and unpredictable opportunities that bring about additional potential benefits for ratepayers. Pointing out that Peoples Gas has replaced main safely and efficiently since 1981 does not diminish the propriety of enhancing that activity and achieving greater savings than might otherwise result. Schott Reb., NS-PGL Ex. JFS-2.0, 12:242 - 13:251 and 8:160 - 9:176.

b. <u>Opposition to Riders</u>

Both Staff witness Mr. Lazare and GCI witness Mr. Brosch have contended that Rider ICR does not meet the purported tests for rate tracking riders. Peoples Gas does not agree that there are rigid prescriptions for employing riders. As Mr. Feingold points out, rate trackers have increasingly become a reasonable and useful mechanism employed by utilities and approved by regulators to recover the costs of extraordinary expenses. Feingold Reb., NS-PGL Ex. RAF-2.0, 32:648-652. Indeed, Mr. Feingold has described several examples of infrastructure riders in existence. Feingold Reb., NS-PGL Ex. RAF-2.0, 33:657-34:680.

In addition, as was discussed in Section VII(A) hereof, the Commission has a long standing policy of implementing rate riders in appropriate circumstances.[23] The circumstances surrounding the acceleration of CI/DI main replacement are an appropriate situation to implement a rider, not unlike other instances in which the Commission has employed riders. The difficulty in forecasting and uncertain timing of the level and incurrence of expenditures are the precise features that the Commission has determined justify rider treatment in other cases, such as in the *CILCO* case discussed in Section VII(A) hereof. Moreover, the very large expenditures that are expected to be involved in infrastructure replacement cost recovery and the very high degree of unforseeability of project expenditures over time render the costs particularly suitable for rider treatment.

c. Acceleration and Rider ICR Would <u>Not Amount to an Extraordinary Price</u>

Ratepayers will not pay a premium for the acceleration through Rider ICR, as urged by Mr. Lazare. Lazare Dir., Staff Ex. 8.0, 36:754-756. Rather, there are unique opportunities for the ratepayers to capture savings through the projects that might permit greater replacement opportunities than would otherwise occur. Aside from time value of money considerations, Rider ICR will not result in additional costs to ratepayers over what would be paid in any event for CI/DI main replacement in the aggregate and Peoples Gas will not obtain any financial benefit that is different from the rate case treatment which it is normally accorded for capital expenditures. Schott Reb., NS-PGL Ex. JFS-2.0, 9:172-181.

Mr. Lazare has offered absolutely no data to support his claim that an extraordinary price would be paid for CI/DI replacement. Expenditures will be made to replace CI/DI mains on the

[23] The parties that oppose rate riders in this proceeding have urged that rate riders are objectionable *per se* because they depart from "tradition" or are "piecemeal". The objections to the tracking features of Rider ICR follow this same misguided and inapt reasoning and must be rejected.

Peoples Gas system and the costs of these replacements will be recovered from ratepayers either in base rates or through Rider ICR. No evidence is in the record that costs recoverable under Rider ICR would exceed costs otherwise recoverable through base rates.

d. A Rate of Return Credit Is Inappropriate

Peoples Gas strongly opposes Staff's proposal to include a rate of return credit from Part 656 in the Rider ICR. While Peoples Gas was amenable to revising its Rider ICR to comport with much of Staff's recommended changes based on Part 656, Peoples Gas does not believe that every single element of Part 656 should be applied to its program. Schott Sur., NS-PGL Ex. JFS-3.0 2Rev., 3:45-51. Rider ICR was intended to be a straightforward mechanism to provide Peoples Gas with some rate recovery for the cost of acceleration of the replacement of CI/DI main between rate cases. Part 656 is a mechanism for the treatment of cost recovery by water utilities. Neither Ms. Hathhorn nor any other party has established why the return feature of Part 656 necessarily applies to natural gas systems or Peoples Gas in particular.

The credit mechanism is highly inappropriate for Rider ICR because it could have the perverse effect of eliminating recovery of the very costs Rider ICR is designed to recover. Rider ICR is designed to recover costs that Peoples Gas actually expends for infrastructure replacement. If the Company does not incur costs, there is no ICR revenue. If the credit operates to limit or reduce the ICR revenue, the Company will be precluded from recovering the costs it would have actually expended for infrastructure replacement. Thus, even after Peoples Gas will have paid for infrastructure replacement and collected the allowed recovery from customers, the credit would, in effect, cause the Company to disgorge those collections and eliminate the very recovery of costs intended by the operation of Rider ICR. Schott Sur., NS-PGL Ex. JFS-3.0 2Rev., 5:92-101. There is simply nothing in the record to support the return on rate base credit mechanism. Mr. Schott's testimony contains numerous reasons why it should not be included but nothing exists beyond *ipse dixit* that supports another conclusion.

In summary, the record in this proceeding amply demonstrates that there are benefits to be obtained by accelerating the replacement of CI/DI main in Chicago and that Peoples Gas can only do so in a financially responsible manner if Rider ICR is approved. Clearly, acceleration of CI/DI replacement and Rider ICR are of significant value to Peoples Gas' customers and the City of Chicago as a whole. The benefits of modernizing the infrastructure and achieving significant savings on behalf of rate payers could be considerable and proposed Rider ICR will provide the Company with a current basis to recover the recurring capital-related costs without the negative financial consequences to the Company.

Infrastructure modernization is a challenge that is being addressed across the nation and in Illinois. Schott Sur., NS-PGL Ex. JFS 3.0 2REV, 7:148-150. These challenges are particularly acute as they pertain to vintage facilities in old urban areas like Chicago.[24] Rider ICR presents the Commission with the opportunity to ensure that the natural gas pipeline infrastructure in the City of Chicago is the most suitable to meet long term service requirements.

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

1. Merits of Energy Efficiency Programs

In *In re WPS Resources, Inc.*, ICC Docket No. 06-0540, the Commission approved a set of conditions under which the merger proposed in that docket was approved. One of the Conditions, No. 27, required that Peoples Gas and North Shore propose a new ratepayer funded energy efficiency program of not less than $7.5 million per year. The Utilities' proposal, embodied in Rider EEP, satisfies the merger condition.

[24] At the hearing, Mr. Schott very aptly noted that Chicago is unique and that its infrastructure situation could warrant a unique solution. Schott, Tr. at 1634:7-1635:16.

The proposed program is explained in the testimony of Ilze Rukis, Integrys Energy Group's Manager – Energy Efficiency and Public Benefits. Rukis Dir., PGL Ex. IR-1.0; NS Ex. IR-1.0. The program would be governed by a Governance Board, consisting of five voting members (ELPC, the Utilities, the City of Chicago, a consumer advocacy group, and a North Shore service territory government or consumer member), and one non-voting member from Staff. Rukis Dir., PGL Ex. IR-1.0,6:130 – 7:141. This membership would insure the independence of the Governance Board, and therefore the entire program, from the Utilities. The Governance Board would evaluate and select a Program Administrator, a Contract Administrator, and a Program Evaluator. *Id.* at 7:142 - 8:160. The independent Contract Administrator would help establish budgets and approve expenditures. *Id.* at 8:166-173. The independent Program Administrator would develop the actual programs, and make reports to the Governance Board. *Id.* at 8:164-168. The independent Program Evaluator would make periodic audits and check the performance of the program against established criteria. *Id.* at 9:188-190. The ministerial function of a Fiscal Agent, who would maintain the accounting reports and pay invoices approved by the Contract Administrator, would be at one of the Utilities. *Id.* at 9:200 - 10:210.

The Utilities anticipate that much of the program would be directed to rebates and other incentives, typically supporting new energy efficient technologies and other gas-saving techniques available for purchase by gas consumers. These could include more efficient furnaces or improved weatherization. Rukis Dir., PGL Ex. IR-1.0, 11:237 - 15:327. The programs would be publicized through the media and point-of-sale locations. *Id.* at 17:370-383.

The Utilities' proposal of a ratepayer-funded energy efficiency program – leaving aside the issue of whether it is implemented through a rider mechanism – enjoyed broad support from the parties. The Environmental Law and Policy Center strongly supports the program. The City of Chicago, Attorney General, and CUB support the program as well. Only Staff objected to the proposed efficiency program. Dr. Rearden was of the opinion that the program was unfair, because it would be funded by all ratepayers, but would only benefit those who chose to participate. Staff Ex. 12.0, 33:680-696. He also called energy efficiency programs economically inefficient, because when energy prices are high, consumers will already have incentives to conserve. Id. at 33:691-34:711. As Ms. Rukis pointed out, Dr. Rearden in effect assumed that the program's Governance Board would choose implementations that are not cost-effective, which should not be the case. Rukis, NS-PGL Ex. IR-3.0, 3:45-64. Dr. Rearden ignored the fact that, in the real world, consumers do not always have the perfect information and rational behavior that economists assume they have. Rukis, NS-PGL Ex. IR-3.0, 2:40-44; Rearden, Tr. at 713:18-714:10. A requirement that the program only invest in cost-effective measures, based on certain tests, would do away with Dr. Rearden's concerns that the program would promote the wrong efficiency measures. Rukis, NS-PGL Ex. IR-3.0, 4:75-80. Moreover, the program would be no more unfair than many other programs, such as publicly funded education. Id. at 4:72-77. Staff's concerns should not keep the Commission from approving these programs, just as they have been approved in neighboring states. Kubert, ELPC Ex. 1.0, 2:37-46.

A funding level of about $7.5 million is appropriate, given the size and type of service territories of the two Utilities. Rukis Dir., PGL Ex. IR-1.0, 4:87-5:96; Rukis Dir., NS Ex. IR-1.0, 4:88-5:98; Rukis Reb., NS-PGL Ex. IR-2.0, pp. 2-3. Accordingly, the Utilities urge the Commission to approve this program.

2. Rate/Rider Treatment

The Utilities' proposed Rider EEP will recover the Utilities' expenses of providing funding for the costs of energy conservation and efficiency programs for their customers through qualified independent third party administrator(s). Feingold Dir., PGL Ex. RAF-1.0, 42:835-837. The purpose of Rider EEP is to compute, on an annual basis, a monthly charge per customer for each applicable service classification to recover the incremental expenses that support the development and implementation of those energy efficiency programs. Grace Dir., PGL Ex. VG-1.0 REV, 40:879-881; NS Ex. VG-1.0 3REV, 35:769-771. The Utilities are proposing rider recovery for expenses related to the proposed energy efficiency programs for two reasons. First, there is precedent for recovering such expenses through a tariff rider. Previously, Peoples Gas had offered energy efficiency programs as part of a statewide least cost planning initiative and recovered such expenses through Rider 16, Adjustment for Incremental Costs of the Energy Conservation Plan. Second, legislation has been offered that may lead to a statewide energy efficiency initiative. As there is potential for the Utilities' customers to fund energy efficiency programs under a statewide initiative, the Utilities would not want to burden its customers with the cost of multiple programs. Grace Dir., PGL Ex. VG-1.0 3REV, PGL Ex. VG-1.0 3REV, 41:914 - 42:920.

ELPC witness Mr. Kubert, Staff witness Mr. Lazare, and GCI witness Mr. Brosch do not support collecting of EEP expenses through a rider. As noted above, Mr. Kubert voiced support for the programs, but not the rider mechanism. Kubert Corr. Dir., ELPC Ex. 1.0, 2:22-3:27.

Mr. Feingold testified that Rider EEP is a necessary complement to the Utilities' proposed energy conservation and efficiency programs, that Rider EEP ensures that the defined level of funding is made available on an ongoing basis to the chosen service providers, and that the Utilities' applicable customers will be charged only for the program costs actually incurred as the types and mix of implemented programs changes over time. Feingold Dir., PGL Ex. RAF-1.0, 42:838-842; Feingold Dir., NS Ex. RAF-1.0, 39:850-854. Furthermore, program cost recovery is considered to be an essential factor in order to achieve utility-sector energy efficiency programs and there should be a clear, reliable and timely regulatory process in place to ensure the recovery of these ongoing expenditures. A rate making mechanism that ensures predictable and timely recovery of energy efficiency and conservation program costs is particularly important for the Utilities because there are added uncertainties surrounding the precise timing of the rollout of their energy efficiency and conservation programs. This programmatic uncertainty makes it difficult to develop a specific amount to represent each year's costs of program implementation. As a result, it is appropriate and necessary for Peoples Gas and North Shore to have the ability to recover such costs through a ratemaking mechanism that can accommodate the anticipated variations in budgeted versus actual costs from year to year. Feingold Dir., PGL Ex. RAF-1.0 43:848-855, Feingold Dir., NS Ex. RAF-1.0, 40:861-869.

Mr. Kubert, while not recommending a rider, agrees to the uncertainty regarding the varying levels of expenditure in an EEP program such as the one proposed here. Mr. Kubert acknowledges that in applying spending levels to People Gas and North Shore revenue, an energy efficiency program for their customers would be $8.7 million on the low end up to $36.5 million on the high end. Kubert Corr. Dir., ELPC Ex. 1.0, 6:114-7:116.

Mr. Lazare criticizes Rider EEP by asserting that Mr. Feingold's reference to uncertainty is unsubstantiated and does not constitute a valid reason to adopt a rider. He also criticizes Ms. Grace's reasoning, claiming that just because a rider was employed in the past does not justify its use to recover EEP costs and that potential legislation is not sufficient justification for a rider.

Lazare Dir., Staff Ex. 8.0, 33:672 - 34:691. Similarly, Mr. Brosch opposes rider treatment for EEP costs, claiming that the size of the EEP recoveries do not justify a special tariff rider and that the differences between program disbursements and the funding levels can be handled through deferral accounting between rate cases. Brosch Dir., GCI Ex. MLB-1.0, 72:4-73:2. Staff witness Ms. Hathhorn recommended certain language changes for Rider EEP and proposed that the Utilities establish an annual reconciliation procedure and internal audit process, as well as change the monthly tariff filing date. Hathhorn Dir, Staff Ex. 1.0, 29:601-605. The Utilities have agreed to the revisions suggested by witness Hathhorn. Grace Reb. NS-PGL Ex. VG-2.0, 51:1128. While the Utilities would accept a deferred account procedure for handling EEP expenditure program recoveries so long as the deferred account process was annual, as opposed to between rate cases, the Utilities do not believe that the objections raised by witnesses Messrs. Brosch and Lazare flatly opposing the rider mechanism are valid. First, the fact that such costs have been previously recovered in a rider is a cogent and persuasive reason for employing a rider to recover EEP programs costs. Not only is the fact indicative of the Commission's employment of riders in general, but it also is very indicative that the type of costs to be recovered are highly suited for rider treatment. Indeed, the difficulty in forecasting and uncertain timing of the level and incurrence of expenditures are the same features that the Commission has determined justify rider treatment in other cases, such as in the *CILCO* case discussed in Section VII(A) hereof. In addition, the size of the expenditures to be recovered under a rider should have no bearing on whether the rider should be employed if the costs otherwise are suitable for rider treatment. In this case, the pending legislative proposals discussed by Ms. Grace offer another reason to have a rider in place to capture any eventual additional related costs. In general, it appears that the objections lodged by the opponents for rider treatment of EEP program costs are more philosophical than anything—those parties simply do not like riders because they view them as "piecemeal" and "nontraditional". These are unpersuasive positions in view of the Commission's long employment of riders, as discussed in Section VII(A).

In their undifferentiated opposition to riders, the opponents ignore that under the Utilities' proposed Rider EEP, customers would receive immediate and direct benefits of reduced base rates to the extent the expense associated with the energy efficiency and conservation programs decreased from the level used to establish the initial adjustment under the Rider. Feingold Reb., NS-PGL Ex. RAF-2.0, 49:996-999. Additionally, under Rider EEP customers will not be subjected to the risk of overpaying for a higher level of expenses associated with the energy efficiency and conservation programs when the expenses decrease from the program's initial funding level. If this expense component were recoverable through base rates, customers would not benefit from lower rates whenever program costs decreased from the level assumed in the Companies' rate cases. Feingold Reb., NS-PGL Ex. RAF-2.0, 51:1039–1044.

3. Other Utilities With Regulatory Approval for Riders

Utilities in various states such as Idaho, Massachusetts, Minnesota, Vermont, and Washington have received regulatory approval to recover the direct costs of their energy efficiency and conservation program through tariff provisions such as adjustment riders. Feingold Dir., PGL Ex. RAF-1.0, 43:860-44:863; NS Ex. RAF-1.0, 40:874-877. Clearly, there is an explicit recognition by the regulators in those states that assured recovery of energy efficiency costs is a necessary step in addressing the barriers many utilities face to investing in more energy efficiency measures. The Commission should approve Rider EEP; it would be in step with the evolving policy making trends across the country.

E. **<u>Rider UBA</u>**

As earlier noted, one of the major business challenges facing the Utilities is rising and uncontrollable bad debt expenses caused primarily by the level of wholesale natural gas prices. High customer bills result in more customers being slow or unable to pay, with higher delinquencies as the consequence. More and higher delinquencies have led to greater net write-offs for the Utilities. Utilities that recover bad debt expense as a fixed cost component in base rates have experienced under-recovery of actual bad debt expenses. Feingold Dir., PGL Ex. RAF-1.0, 37:725-732; NS Ex. RAF-1.0, 34:734-741.

Aside from certain mitigation measures that address bad debt that has already accumulated, which the Utilities have aggressively pursued, there is little that can be done to reduce bad debt levels. *See* Feingold Dir., PGL Ex. RAF-1.0, 38:745-752; NS Ex. RAF-1.0, 35:756-763. It is simply indisputable that the circumstances that have given rise to the order of magnitude and more volatile nature of bad debt experienced by the Utilities are caused by events that are almost entirely out of the control of the Utilities. Further, the static rate methods that have been historically employed render it largely impossible for Utilities to protect themselves financially. *See* Feingold Dir., PGL Ex. RAF-1.0, 37:734-738; NS Ex. RAF-1.0, 34:744-749. Additionally, the Utilities have demonstrated that the financial marketplace has recognized the negative financial impacts of bad debt expense and the need for regulatory relief. *Id* at 38:755-39:768; 35:766-36:779. Mr. Borgard also has demonstrated in Peoples Gas Ex. LTB-1.5 and North Shore Gas Ex. LTB-1.4 that the Utilities' bad debt experience has dramatically increased.

Thus, uncollectible accounts are a rising and recurring business expense for the Utilities and are a reflection of economic conditions that exist from time to time, the level of gas commodity and delivery prices and the demographics of the Utilities' service territories. As a result, bad debt is uncontrollable, highly variable and unpredictable, with resulting negative financial consequences. The Utilities' proposed Rider UBA would provide them with the ability to recover the ongoing level of these unforeseeable and largely unavoidable bad debt expenses related to purchased gas costs. To the extent that gas commodity prices fluctuate upward or downward and influence bad debt levels, Rider UBA will swiftly recognize any increases or decreases in bad debt levels caused by such price changes. *See* Feingold Dir., PGL Ex. 1.0, 39:781-40:792; NS Ex. 1.0, 36:792 - 37:803.

Rider UBA itself is simply a monthly volumetric adjustment, to be applied to company supplied gas, to recover gas cost related bad debt expense from sales customers. The adjustment would be computed by applying the Utility's percentage adjustment factor. This adjustment factor will be determined by multiplying the uncollectible expense percentage approved in this rate proceeding by the forecasted Gas Charge revenues arising from the application of Rider 2 to be effected for the upcoming month and dividing by the applicable volumes for the same month, yielding the effective adjustment. Any differences between billed revenues and uncollectible expenses under the Rider will be reconciled on an annual basis and amortized over a 10 month period, with the resulting adjustment added to customers' bills during that period. The Companies have also agreed to conduct an annual internal audit and to file a monthly report with the Commission, as well as an annual report in February of each year to determine the earlier discussed reconciliation adjustment. Grace Dir., PGL Ex. VG-1.0 REV, 44:973 - 45:996; Grace Dir., NS Ex. VG-1.0 3REV, 39:863 - 40:886.

Ms. Grace has determined that the test year uncollectible gas cost expenses to be recovered through Rider UBA are $26.7 million and $1.5 million dollars for Peoples Gas and North Shore, respectively. Grace Dir., PGL Ex. VG-1.0, 45:1006-1007; Grace Dir., NS Ex. VG-1.0 3REV, 41:896-897. Rider UBA will only pertain to the gas cost portion of the

Utilities' bad debt expense. The Utilities propose to remain at risk for the portion of bad debt expense related to the non-gas cost bad debt expense. Hence, non-gas cost uncollectible expense would be recovered in base rates. In the event that the Commission does not approve Rider UBA, however, the Utilities would continue to include and recover total bad debt allowance in base rates. Ms. Grace has developed rates that reflect both eventualities. *See* NS-PGL Ex. VG 2.4-PGL, pages 1 and 2, and NS-PGL Ex. VG-2.4-NSG, pages 1 and 2.

Mr. Brosch opposes Rider UBA because, among other reasons, he contends the overall uncollectible expenses of Peoples Gas are small in relation to overall operating costs and that they are not large enough to jeopardize the financial integrity of the utility. Brosch Reb., GCI Ex. MLB-2.0, 21:10-12. Mr. Lazare makes similar assertions and also makes an argument that the Utilities earned their approved rate of return in a year in which bad debt levels were high. Lazare Dir., Staff Ex. 8.0, 30:593-596; Staff Ex. 8.0, Schedule 8.3, pages 3 and 4.

No party has presented evidence that disputes that the level of uncollectible expense on the Utilities' system is substantially greater than has historically been the case or presented evidence that the fluctuating and unpredictable bad debt expense can be reasonably managed without a Rider UBA type of mechanism. The only substantive criticism of Rider UBA that has been offered is that bad debt has stabilized and is not volatile in relation to operating expenses.[25] This argument is simply beside the point and fails to recognize the direct link between purchased gas expenses and bad debt experience. The relationship between bad debt and operating expenses is irrelevant as to whether bad debt expenses are significant. $26.7 million and $1.5 million of gas cost-related bad debt are substantial amounts and cannot be dismissed out of hand. Moreover, it certainly can not be seriously argued that purchased gas expenses are "stable" and

[25] The suggestion that extraordinary bad debt levels may be disregarded because the Utilities may have nonetheless earned their approved rate of return is irrelevant. The outcome of the utility return is influenced by many factors.

not volatile. In addition, bad debt expenses are far more volatile than other operating expenses excluding gas costs. NS-PGL Ex. RAF-2.2.

In addition, the relationship between bad debt and gas prices is undeniable. The unpredictability of gas costs, among other reasons, is one of the justifications for tracking gas costs in Rider 2. Bad debt should be accorded similar treatment and the Utilities' proposal to recover the gas cost portion of uncollectible expense is sound and reasonable. The demonstrated volatility of gas prices and the attendant level of bad debt are phenomena that did not exist at the time the Utilities filed their last rate cases, but clearly existed during the 10-year period subsequent to those filings. Such circumstances justify a departure from the prior practice of recovering uncollectible expense entirely through base rates. To continue to employ the "traditional" rate model would be unreasonable, unjust and unsound regulatory policy in the face of the uncontroverted facts.

As with the Utilities' other rider proposals, Rider UBA type mechanisms have been widely accepted across the country. The record is uncontroverted that numerous state regulatory commissions have approved uncollectible expense tracking mechanisms. At least 17 gas utilities in 10 states employ them. Feingold Dir., PGL Ex. RAF-1.0, 41:821-823; NS Ex RAF-1.0, 38:833-835. Thus, the Commission would not be departing from sound and respected regulatory policy by approving an uncollectible mechanism for the Utilities. Of course, as with the other rider proposals, witnesses Messrs. Brosch and Lazare oppose Rider UBA on the same rigid philosophical grounds as discussed in regards to Rider EEP and the same counterarguments apply. The Commission should approve Rider UBA.

VIII. COST OF SERVICE

A. Overview

The Companies have presented comprehensive and well reasoned Embedded Costs of Service Studies ("ECOSS") sponsored by Mr. Amen. The ECOSS studies presented by Mr. Amen on behalf of Peoples Gas and North Shore are detailed and consistent with well settled principles of cost classification, cost allocation and cost causation. The ECOSS for Peoples Gas is set forth in PGL Exs. RJA-1.1, 1.2 Rev. - 1.4, 1.7 Rev. - 1.8, 1.9 Rev., and 1.10 REV and North Shore's is set forth in NS Exs. RJA-1.1, 1.2 Rev. - 1.4, 1.7 Rev. - 1.8, 1.9 Rev., and 1.10 REV. The Companies' ECOSS have reasonably established cost responsibility among the various customer classes served by the Utilities. Hereinafter, the Utilities' ECOSS will be referred to as "the ECOSS" collectively unless a reference to ECOSS shall be preceded by the specific company name. The ECOSS has matched cost causation with the customers which have caused the particular cost, thereby following the sound theoretical principle that cost incurrence should follow cost causation. As Mr. Amen notes in his testimony,

> "[T]he costs that customers become responsible to pay should be those costs that the particular customers caused the Utility to incur because of the characteristics of the customer's usage of the Utility's service."

Amen Dir., PGL Ex. RJA-1.0, 7:157-159; NS Ex. RJA 1.0, 7:158-161. The Companies are the only parties which have submitted ECOSS in these proceedings. Mr. Luth, however, made certain adjustments to the Companies' ECOSS using the Companies' ECOSS models. Only three parties submitted evidence taking issue with various aspects of the ECOSS. None of those parties submitted an ECOSS themselves and none appear to take issue with the Companies' approach broadly. Rather, the parties, including Staff, CUB-City and AG, have made selective criticisms of the ECOSS.

B. Embedded Cost of Service Study

1. Uncontested Issues

a. Functionalization of Intangible Plant Accounts 303.1 and 303.2

The Utilities' proposal functionalized Accounts 303.1 and 303.2 costs solely as customer-related costs. Staff witness Mr. Luth proposed that the Utilities functionalize those Accounts according to their relative weight of depreciable Production, Storage, Transmission, Distribution and Customer Accounts Plant. Luth Dir., Staff Ex. 7.0, 4:63-65. The Utilities have accepted Mr. Luth's proposal which recommends that costs in Account Nos. 303.1 and 303.2 should not be based solely on customer account costs, but should be functionalized as Customer Accounts, Distribution related and the remaining amounts spread ratably among the functions to reflect the general and administrative uses of the remaining software and systems applications. Amen Reb., NS-PGL Ex. RJA-2.0, 11:237-240; NS-PGL Ex. RJA-2.3.

b. Classification of Distribution Plant Account No. 375

The Utilities proposed the allocation of Account No. 375, Distribution Plant-Structures Improvements, as a combination of demand and customer costs. Staff witness Mr. Luth recommended that Account No. 375 should be classified entirely as a demand-related cost rather than a combination of other costs including, customer costs. Luth Dir., Staff Ex. 7.0, 4:79-89. The Companies have accepted the proposal of Staff witness Luth and agreed to classify Account No. 375 solely as a demand-related cost. Amen Reb., NS-PGL RJA-2.0, 12:256-257; Amen Reb., NS-PGL RJA-2.3 and NS-PGL RJA-2.4.

2. Contested Issues

a. Coincident Peak Versus Average and Peak Allocation Methods

The ECOSS is detailed, reflects well founded principles and cost dynamics and the specific characteristics of the Peoples Gas and North Shore systems. The Companies have chosen to present the ECOSS utilizing three (3) different methods of allocating system demand costs. While the Companies have indicated their preference for the Coincident Peak (CP) demand allocation methodology, they each also presented the ECOSS utilizing two other allocation methodologies – (1) a Coincident Peak method, with a portion of the distribution mains classified as customer related, and (2) an Average and Peak (A&P) approach. While the Companies have established that the CP method is the most appropriate one for demand cost allocation in view of the specific characteristics of the Peoples Gas and North Shore systems, they also presented the other two methodologies to demonstrate to the Commission the range of results which can be achieved under various methods. Nevertheless, applying the most important cost allocation principle, the allocation of the costs to the customers that caused them, the CP method produces the most conceptually sound and balanced outcome.

The CP method is based on the design days of the Peoples Gas and North Shore systems. Design day was utilized as Peak Demand Design is always utilized when designing a gas distribution system to accommodate the gas demand requirements of customers served by the system. Amen Dir., PGL Ex. RJA-1.0, 19:419-421; Amen Dir., NS Ex. RJA-1.0, 19:422-424. By sizing an investment for peak demands, the Utilities are ensured the ability to meet the service obligations throughout the year. Design day demand directly measures the gas demand requirements of the Utilities' firm service customers which create the need for the Utilities to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis. Amen Dir., PGL Ex. RJA-1.0, 21:456-458, NS Ex. RJA-1.0, 21:459-462. Hence, Design Peak

Day is directly attributable to the demands that particular customers require and thus cause. Design Peak Day is therefore the best way to capture the true cost causative factors of the Utilities' operations in the ECOSS. Simply put, the use of Design Day to allocate peak demand related costs is the most reasonable approach because it is related to the actual system as it was built to serve customers' specific needs.

Mr. Luth on behalf of the Staff and Mr. Thomas on behalf of CUB-City advocate the use of the A&P method for demand cost allocation. Neither Mr. Luth nor Mr. Thomas explains how the A&P method, particularly its use of average usage, relates to how the utility systems were built. Nor have they addressed how a utility's system sized only to accommodate average gas demands would be able to meet peak system demands and why giving recognition to system utilization addresses the principle of cost causation. Those parties have simply offered conclusory assertions that the A&P method should be approved for the Utilities. In the absence of detailed analyses of why the A&P should be adopted for the Peoples Gas and North Shore systems, the Utilities' proposed use of the CP method should be approved because it has been supported with both sound reasoning and adequately detailed analysis. While the two aforementioned parties have opposed the CP method, they have not adequately explained why the A&P method or another method is more reasonable.

b. Classification of Uncollectible Account Expenses Account No. 904

In the ECOSS, the Utilities classified Account No. 904 costs, Uncollectible Account Expenses, as customer costs. Mr. Luth urges that Account No. 904 expenses should be classified as a combination of customer costs, demand costs, and commodity costs, including gas costs. Luth Dir., Staff Ex. 7.0, 9:154-157. Mr. Luth would also apportion the uncollectible expense in each customer class to the respective demand, customer and commodity classifications by the relative weight or percentage of revenue requirement from each customer class resulting from demand costs, commodity costs, customer costs and gas costs. The Utilities' proposal is the most appropriate because Account No. 904 costs are a function of customers' unpaid bills, not the underlying components of those bills. The uncollectible expenses have no bearing on whether the expenses are fixed or variable charges or the specific costs which may be covered by those bills. Residential customers do not even receive fully allocated costs. Amen Reb., NS-PGL Ex. RJA-2.0, 13:278-282. Hence, any attempt to match the recovery of uncollectible expenses to specific charges is misplaced because the amount of uncollectible expense (or any other expense) that is recovered by the customer demand and distribution charges of a particular service schedule is uncertain because the revenues produced by any customer class are not necessarily equal to their fully allocated costs. Furthermore, the customer, demand and commodity related costs for a particular customer class are not translated directly into similar rate components in the Companies' rate schedules. Amen Sur., NS-PGL Ex. RJA-3.0, 6:123-128. Mr. Luth's proposal regarding Account No. 904 should be rejected because he seeks to inappropriately use rate design as justification for cost classification and allocation in an ECOSS. This is polar opposite to what is conventionally sought to be achieved by an ECOSS. An ECOSS drives rate design and rate design should never drive the cost of service.

c. <u>Allocation of Costs to S.C. No. 1H and S.C. No. 1N</u>

The Companies propose to bifurcate their small residential service classification rates into two service classifications, heating, S.C. No. 1H, and non-heating, S.C. No. 1N. Only one party, Mr. Glahn, on behalf of GCI, submitted testimony flatly opposing the rate classification bifurcation. While not opposing the Companies' proposed bifurcation, Mr. Luth has made problematic proposals to determine customers' eligibility for S.C. Nos. 1H and 1N. The Utilities' proposal to bifurcate S.C. No. 1 into heating and non-heating categories is reasonable and supported by the evidence presented by the Utilities. The Utilities have established that bifurcating S.C. No. 1 will allow better alignment of costs and revenue recovery, as well as provide more equity between and within rate classes, by setting rates closer to the costs of service. Grace Dir., PGL Ex. VG-1.0 REV, 11:230-232, NS Ex. VG-1.0 3REV, 9:191-193. It is undisputed that under the Utilities' current rate structure, an intra-class subsidy from heating customers to non-heating customers exists and that the single rate for heating and non-heating customers slows the movement of non-heating customers to costs. Grace Dir., PGL Ex. VG-1.0 REV, 11:232-237, NS Ex. VG-1.0 2Rev., 9:193-197. The Utilities have demonstrated that fixed costs for heating customers are twice as high as those for non-heating customers, and that such a significant difference would result in the recovery of fixed costs through fixed charges under a single rate which could overburden small non-heating customers. Grace Dir., PGL Ex. VG-1.0 REV, 11:241-246; NS Ex. VG-1.0 3REV, 9:201-10:205.

Peoples Gas and North Shore have demonstrated that heating and non-heating designations have been tracked for the last twenty years and are based on company-gathered information when service is commenced for customers as well as from follow-up calls to customers, service inspections and billing department analyses of customer usage. Grace Reb., NS-PGL Ex. VG-2.0, 31:675-679. The Utilities have even submitted evidence showing that 97% of Peoples Gas' and 91% of North Shore's S.C. 1N monthly bills are for 50 therms or less, which supports the assumption that S.C. 1N customers generally use less than 500 annual therms and that heating customers would be expected to use more than 500 therms a year. The Utilities have also determined that nearly all their S.C. Nos. 1N and 1H customers have been properly classified. Furthermore, the Utilities have demonstrated that usage is one of a few important factors that would be considered to ensure that customers are properly classified. Grace Reb., NS-PGL Ex. VG-2.0, 32:682-696. The Utilities have also asserted their intention to specifically notify customers of the new bifurcated rate classifications. The record thus simply demonstrates that there is a reasonable basis for bifurcating Service Classification No. 1.

Even Mr. Glahn, the only witness to oppose the bifurcation itself, admits to only having problems with the Utilities' implementation of the bifurcation. Mr. Glahn even admits that the heating and non-heating distinction is "common in the industry". Glahn Dir., GCI Ex. 3.0 REV, 16:1-2. Mr. Glahn's perceived implementation problems are that: (1) the proportion of costs assigned to heating customers appears "implausibly" high; (2) rates disproportionately impact low and fixed income customers; (3) there appears to be a shift in the subsidy to heating customers subsidizing non-heating customers. *Id.*, at 16:3-8.

Mr. Glahn's assertion that the cost differentials between S.C. No. 1 and S.C. No. 1N are "implausibly high" has no bearing on whether bifurcation is appropriate. First, Mr. Glahn's assertion is ill-conceived and flawed. The average per customer calculations he makes for service plant ignores the occurrence of multiple S.C. No. 1N customers served by shared gas service lines, which is the predominant circumstance for S.C. No. 1N residential customers on the Peoples Gas system. Amen Reb., NS-PGL Ex. RJA-2.0, 15:325-336. Moreover, the ECOSS for S.C. No. 1 and S.C. No. 1H properly accounts for the sharing of service lines by multiple customers. Amen Reb., NS-PGL Ex. RJA-2.0, 16:339-353.

The existence of shared service lines and the fact that the overwhelming number of S.C. No. 1N customers are connected to shared services has no logical connection to any purported bifurcation along multi-family versus single family lines, or single meter versus separately metered lines, as asserted by Mr. Glahn. Glahn Reb., GCI Ex. 6.0 REV, 4:78-81. Mr. Glahn also makes an inaccurate generalization, that multi-family units spread fixed costs over a larger customer base driving down costs per customer, which is simply unsupported and conclusory. *Id.*, 4:84-86. Similarly, Mr. Glahn's suggestion that a multi-family versus single family bifurcation might be appropriate is unsupported by the facts. The Utilities' bifurcation into heating and non-heating classes appropriately recognizes those customers' respective load characteristics by reflecting the single largest component of distribution plant which drives cost responsibility, *i.e.*, the cost of mains. The capacity cost of mains is driven by peak load and, as a group, heating customers place a significantly higher peak load on the system than do non-heating customers. Dividing S.C. No. 1 customers into multi-family and single family classes would do nothing to recognize this important cost causation factor and only a heating versus non-heating classification would do so. Amen Sur., NS-PGL Ex. RJA-3.0, 8:163-175.

Similarly, Mr. Glahn's criticism that the 1N/1H bifurcation disproportionately impacts low income customers is unavailing. Glahn Dir., GCI Ex. 3.0 REV, 17:19 - 18:2. Indeed, as established by Ms. Grace, under the Utilities' bifurcation proposal, the resulting rates will be lower than those proposed by Mr. Glahn, particularly during the winter. Grace Reb., NS-PGL Ex. VG-2.0, 33:714-719.

Finally, Mr. Glahn's assertion that bifurcation is not needed because there may have been a subsidy shift lacks merit. He concludes that any apparent subsidy is from heating customers to non-heating customers. Glahn Dir., GCI Ex. 3.0 REV, 23:1-2. That is consistent with the Utilities' positions that the current rate structures result in an intra-class subsidy from heating customers to non-heating customers. However, a primary purpose of bifurcation is to better align costs and revenue recovery. Grace Dir., PGL Ex. VG-1.0 REV, 11:230-237; Grace Dir. NS Ex. VG-1.0 3REV, 9:191-197. Because the fixed costs for S.C. No. 1H are twice as high as the fixed costs for S.C. No. 1N, the current single service rate structure is not an appropriate alignment of costs and recovery and overburdens smaller use non-heating customers. Grace Dir., PGL Ex. VG-1.0 REV, 11:241-244; Grace Dir., NS Ex. VG-1.0 3REV, 9:200 - 10:204.

Further, Mr. Glahn supports his assertion by comparing the difference between the cost recovery percentages of S.C. No. 1 and S.C. No. 1N, before and after the proposed rate increase. He concludes that since the differences between the percentages remain basically the same before and after the proposed rate increase, 8.38% and 8.3%, respectively, bifurcation of S.C. No. 1 is unwarranted. Glahn Dir., GCI Ex. 3.0 REV, 23:6-10. Mr. Glahn's basic comparison proves nothing in respect of the appropriateness of bifurcation. Moreover, Ms. Grace establishes that the proposed bifurcation does not result in higher rate increases for heating customers, contrary to Mr. Glahn's assertion. Grace Reb., NS-PGL Ex. VG-2.0, 33:724 - 34:728.

Mr. Luth has not indicated that he opposes the Companies' bifurcations. However he did put forth proposals to determine customers' eligibility for S.C. Nos. 1N and 1H. His initial proposal was problematic for a variety of reasons. Grace Reb., NS-PGL Ex. VG-2.0, 26:545 - 31:672. In response to the litany of problems associated with his initial proposal, Mr. Luth replaced that proposal with a new proposal which does not eliminate those already identified problems and in fact introduces many new problems. Grace Sur., NS-PGL Ex. VG-3.0, 7:144 - 9:197. Mr. Luth has not demonstrated that his proposals are warranted, practical or workable.

d. <u>Allocation of Distribution Plant Account No. 385</u>

Account No. 385 represents industrial measuring and regulating station equipment expense. Peoples Gas has allocated the overwhelming majority of Account No. 385 costs to S.C. No. 2. In his Direct Testimony, Mr. Glahn proposed that Account No. 385 expense be allocated entirely to S.C. No. 4 because S.C. No. 4 best fits the definition of "Large Industrial". He also vaguely suggested that S.C. No. 5[26] might also be a repository for such costs. Glahn Dir., GCI Ex. 3.0 REV, 26:19-27:2. Mr. Glahn appears to have based his proposal on what he asserts is the unlikelihood that Peoples Gas keeps as detailed records for S.C. No. 2 as it does for S.C. No. 4, Glahn Dir., GCI Ex. 3.0, 24:14-15, and the unlikelihood that an S.C. No. 2 customer would deserve the equipment described as "special and expensive", appearing to reason that S.C. No. 2 customers are small businesses. Glahn Dir., GCI Ex. 3.0 REV, 25:16-22. After Peoples Gas pointed out that Mr. Glahn's assumptions of unlikelihood were utterly untrue, Amen Reb., NS-PGL Ex. RJA-2.0, 17:363-18:387, Mr. Glahn changed his approach. In his Rebuttal Testimony, he proposed that Account 385 costs should be directly charged as a facilities charge or metering surcharge to the individual customers generating those costs. Glahn Reb., GCI Ex. 6.0 REV, 6:137-139. Mr. Glahn claims the proposal is justified because he believes the Company can track the costs of Account No. 385 facilities to individual customers; the customers may move from one rate classification to another; and the small number of customers causing the cost justifies a direct charge. *Id.* at 5:124-127.

As Mr. Amen points out, such an approach would be both impractical and inappropriate. First, applying Peoples Gas' methodology, the Account No. 385 expenses increase the S.C. No. 2 Meter Class No. 1 charge by $.05 and the Meter Class No. 2 charge would decrease by $.13. Thus, the overall impact of the issue Mr. Glahn raises is *de minimis*. Amen Sur., NS-PGL Ex. RJA-3.0, 11:242-245. Furthermore, Account No. 385 represents less than 0.04% of Peoples Gas' customer related distribution plant. *Id.*, at 10:213-214. Moreover, Mr. Glahn's proposal raises questions of fairness and equity with respect to the treatment of customers whose costs can be specifically identified to them. The Utilities have the capability to identify the specific plant

[26] Mr. Glahn incorrectly identifies S.C. No. 5 as standby service. Glahn Dir., GCI Ex. 3.0 Rev., 27:1-2.

costs of meters, regulators and services with individual customers in all of its service classes. Hence, all such charges could be directly charged to customers creating a multiplicity of charges and an impractical rate approach. A sound rate structure should include the practical attributes of simplicity, understandability, certainty and feasibility of application. Amen, Sur., NS-PGL Ex. RJA-3.0, 10:223-11:231. Mr. Glahn's proposal is entirely inconsistent with such attributes and must be rejected.

e. <u>Differentiated Class Rates of Return</u>

The Companies calculated at present rates an average return in their respective ECOSS' of 4.88% for Peoples Gas and 7.12% for North Shore. Amen Dir., PGL Ex. RJA-1.0, 33:740; NS Ex. RJA-1.0, 33:697. Mr. Amen testified that his ECOSS allocates revenue responsibility at an equalized class rate of return on investment of 8.25% (Peoples Gas) / 8.57% (North Shore) under proposed rates. Amen Dir., PGL Ex. RJA-1.0, 2:28-31; NS Ex. RJA-1.0, 2:27-30. Mr. Thomas assumes this means that the Companies' ECOSS provides that each customer class contributes precisely the same rate of return. Additionally, he claims that residential customers' gas usage is affected by the weather and commercial customers' usage is affected by economic conditions. Thomas Dir., CUB-City Ex. 1.0, 77:1868-1872. Mr. Thomas appears to contend that this difference in gas usage between the two customer groups creates different revenue-related risk factors for the Companies, which in turn affects the Companies' return on equity because this is determined by "riskiness". Therefore, he concludes that each customer class must provide a different level of risk to the overall cash flow risk of the Companies. *Id.*, at 1873-1876. Mr. Thomas makes no effort to support his observation with an analysis of these purported different risks. Indeed, he admits that he is not even proposing any specific adjustments but merely making an observation to cast doubt on Mr. Amen's ECOSS results. Thomas Dir., CUB-City Ex. 1.0, 77:1876-78:1878. The fact is, however, that no evidence was presented by Mr. Thomas or any other party which suggests that the notion of risk adjusted rates of return by class is an appropriate topic for consideration in these proceedings.

The issue has no bearing on the identification of cost responsibility of the customer classes on an equal footing, at the system average, or "equalized" rates of return, which provides the correct starting point for determining an appropriate level of class revenue responsibility. Amen Reb., NS-PGL Ex. RJA-2.0, 19:417-422. Absent some demonstrated causal link between a utility company's customer class composition and its capital costs, the concept of relative customer class risk is inapplicable as a basis for setting customer class target rates of return within the framework of a cost of service study. Amen Sur., NS-PGL Ex. RJA-3.0, 13:271-275.

f. Allocation of Revenue Requirement to Customer Classes

Mr. Thomas "cautions" the Commission not to solely rely on the Companies' ECOSS for the purposes of designing rates for customers because he claims the allocation process utilized contains significant "uncertainties." CUB-City Ex. 1.0, 72:1742-1745. Mr. Thomas' assertions appear to be an attempt to cast doubt on the usefulness of cost of service as a basis for apportioning revenue responsibility among the customer classes. The Companies have not suggested it to be the only consideration nor have they suggested that other factors are irrelevant to the revenue allocation process. In the absence of any alternative approaches offered by Mr. Thomas or any other party, however, the ECOSS stands as the most reasonable basis for establishing cost responsibility among the customer classes.

IX. RATE DESIGN

A. Overview

The Utilities have not filed a rate case since 1995, and the current tariff book was created that year. The tariff books submitted by the Utilities in these proceedings are completely new and have been submitted as IL.C.C No. 28 and IL.C.C No. 17 for Peoples Gas and North Gas, respectively. *See* Grace Dir., PGL Ex. VG-1.1 and NS Ex. VG-1.1.

In designing rates, the Utilities have sought to accomplish six major objectives. They are to (1) better align costs and revenue recovery, (2) provide more equity between and within rate classes, (3) maintain rate design continuity, (4) reflect gradualism, (5) retain customers on the Utilities' systems and (6) consolidate certain transportation riders while providing new service options for transportation customers. Grace Dir., PGL Ex. VG-1.0 REV, 4:68-72; NS Ex. VG-1.0 2REV, 4:68-72. Objectives 1 through 5 will be addressed in this Section IX and objective 6 will be addressed in Section X, below.

The Utilities have presented analyses that reflect their revenues under present and proposed rates with Rider UBA. *See* Grace Dir., PGL Ex. VG-1.1; NS Ex. VG-1.2. These exhibits also reflect the proposed transportation diversity factors of .87 and .75 for transportation customers of Peoples Gas and North Shore, respectively. *See* Grace Dir., PGL Ex. VG-1.0 REV, 5:88; NS Ex. VG-1.0 2REV, 5:88 and PGL Ex. VG-1.2, 1; NS Ex. VG-1.2, 1. The Utilities have submitted additional exhibits which show rate and revenue impacts with Rider UBA expenses recovered through base rates, rather than through a rider mechanism. *See* Grace Dir., PGL Ex. VG-1.0 REV, 5:90-94; NS Ex. VG-1.0 3REV, 5:90-93 and PGL Ex. VG-1.2, page 2 and NS Ex. VG-2.1, page 2. Rider UBA places recovery of the gas cost portion of uncollectible expense in a rider rather than base rates. If the Commission does not approve this proposal, the Companies' base rates must include the full uncollectible expense. Accordingly, the Companies' rate and revenue data reflect the preferred rate design, which includes Rider UBA as well as rate and revenue data with uncollectible expense in base rates without Rider UBA.

The Utilities utilized Mr. Amen's ECOSS as the basis for the determination of the revenue requirement and resulting proposed rates in this proceeding, including the analyses without Rider UBA. The Companies used the ECOSS to move rates toward cost-based rates and to better align charges with like costs. The ECOSS was also used as the basis for bifurcating Service Classification No. 1 into two new service classifications: S.C. No. 1N, Small Residential Non-Heating Service, and S.C. No. 1H, Small Residential Heating Service. Grace Dir., PGL Ex. VG-1.0 REV, 6:112-117, NS Ex. VG-1.0 3REV, 6:111-116. Utilizing the ECOSS results which determine the cost of service for each service classification, North Shore proposes to continue to set all its service classifications at cost. Peoples Gas proposes to set all service classifications, except S.C. Nos. 1N, 1H, and 2, at cost. The remaining revenue requirement for S.C. Nos. 1N, 1H and 2, is allocated utilizing the equal percentage of embedded cost ("EPEC") methodology which is discussed in more detail in section B(1) of this Section IX.

Almost all of the Utilities' costs, about 95% for Peoples Gas and about 98% for North Shore are fixed, *i.e.*, they do not vary with throughput, and the Utilities have traditionally recovered a greater portion of their costs through non-fixed volumetric charges. The Utilities' last rate case filed about 12 years ago reflected costs that were 98% and 97% fixed for Peoples Gas and North Shore, respectively. Less than 30% of fixed costs were recovered through fixed charges. *See*, Dockets Nos. 95-0031 and 95-0032. This mismatch of fixed costs and non-fixed charges practically assures that the Utilities will either over or under-earn their Commission approved revenue requirement and that customers will either over or under pay their share of such costs. To partially remedy this, the Utilities are proposing to recover more fixed costs through fixed charges. Grace Dir., PGL Ex. VG-1.0 REV, 8:168-9:184; NS Ex. VG-1.0 3REV, 6:130-7:144.

Generally the Utilities have proposed to increase customer charges in an effort to recover more fixed costs in the fixed charge. The relative increase in customer charges proposed by the Utilities is consistent with a growing trend whereby public utility commissions have approved greater fixed cost recovery in fixed charges. This trend has resulted in the approval of rate models where all fixed cost are recovered through a fixed charge, such as the Straight Fixed Variable "SFV" rate design or customers paying a largely flat charge for utility delivery service, with little or no volumetric charge. *See Re Atlanta Gas Light Company*, 2001 WL 1776861 (Ga. P.S.C., Sep 18, 2001) (Docket No. 8516-U). Greater fixed cost recovery through customer charges stabilizes the non-gas cost delivery charge portion of customers' bills and stabilizes the variability in earnings related to variations in customer consumption caused by weather and other conditions outside the Utilities' control. While the Utilities have demonstrated that an SFV rate design would be the optimal one, PGL Ex. VG-1.0 REV, 17:360-18:388; NS Ex. VG-1.0 3REV, 14:309-15:337, the Utilities, instead, are proposing only to recover a greater portion of fixed cost through increased customer charges.

Other parties to these proceedings have not submitted evidence that the Utilities' move toward greater fixed cost recovery through higher customer charges is unwarranted. Rather, those parties have taken issue with specific aspects of the Utilities' S.C. No. 1N and S.C. No. 1H proposals. The Commission has urged Peoples Gas to increase its customer charge in future rate proceedings to move it closer to cost. *Re Peoples Gas Light and Coke Company*, 1995 WL 17200632 (Ill.C.C. Nov 8, 1995) (Docket No. 95-0032). The Companies' proposals are consistent with this policy.

The particulars of the rates and rate design proposals of the Utilities and other parties are discussed below.

Generally, as to Peoples Gas, the Company has proposed ten major changes to its base rates and other charges. These are the following.

1. S.C. No. 1, Small Residential Service, will be bifurcated into two service classifications: S.C. No. 1N, Small Residential Non-Heating Service, and S.C. No. 1H, Small Residential Heating Service.

2. The monthly customer charge for S.C. No. 1N customers will be increased. The distribution charge, which is a two-block rate structure under current S.C. No. 1, will become a flat charge.

3. The monthly customer charge for S.C. No. 1H customers will be increased. The distribution charge will reflect a decrease in the end block with a greater percentage of costs being allocated to the front block of the current two-block rate structure.

4. The monthly customer charges for each Meter Class under S.C. No. 2, General Service, will be increased. The distribution charge will reflect an increase in the front and middle blocks and a decrease in the end block of the three-block rate structure.

5. S.C. No. 3, Large Volume Service, and S.C. No. 4, Large Volume Demand Service, will be combined under S.C. No. 4. S.C. No. 3 will be eliminated. The monthly customer charge and demand charge will be decreased. The distribution charge and standby service charge will be increased. This service classification is set at cost.

6. The monthly customer charge and distribution charge for S.C. No. 6, Standby Service, will be increased. The demand charge will be decreased and will reflect a single demand charge rather than the separate demand charges for heating and non-heating customers under current rates. This service classification is set at cost.

7. The customer charge and distribution charge for S.C. No. 8, Compressed Natural Gas, will be increased. This service classification is set at cost.

8. Service reconnection charges and service activation charges will be restructured to reflect a base charge and charges for additional appliances.

9. The Charge for Dishonored Checks and/or Incomplete Electronic Withdrawal will be increased to better reflect prevailing rates for such checks and transactions and to discourage customers from making such deficient payments to the Company.

10. The Company is proposing a new charge for a Second Pulse Data Capability to accommodate customers' requests for this service. *See* Grace Dir, PGL Ex. VG-1.0 REV, 9:188-10:219.

Generally, as to North Shore, the Company has proposed nine major changes to its base rates and other charges. These are the following.

1. S.C. No. 1, Small Residential Service, will be bifurcated into two service classifications: S.C. No. 1N, Small Residential Non-Heating Service, and S.C. No. 1H, Small Residential Heating Service.

2. The monthly customer charge for S.C. No. 1N customers will be increased. The distribution charge, which is a two-block rate structure under current S.C. No. 1, will become a flat charge. This service classification is set at cost.

3. The monthly customer charge for S.C. No. 1H customers will be increased. The distribution charge will reflect a decrease in the end block with a greater percentage of costs being allocated to the front block of the current two-block rate structure. This service classification is set at cost.

4. The monthly customer charges for each Meter Class under S.C. No. 2, General Service, will be increased. The distribution charge will reflect an increase in the front and a decrease in the middle and end blocks of the three-block rate structure. This service classification is set at cost.

5. The monthly customer charge, distribution charge, demand charge and standby service charge for S.C. No. 3, Large Volume Service will be decreased. The increased. The demand blocks for this service classification will be changed from 5,000 therms and over 5,000 therms to 10,000 therms and over 10,000 therms. This service classification is set at cost.

6. The monthly customer charge and distribution charge for S.C. No. 5, Standby Service, will be increased. The demand charge will be decreased. This service classification is set at cost.

7. Service reconnection charges and service activation charges will be restructured to reflect a base charge and charges for additional appliances.

8. The Charge for Dishonored Checks and/or Incomplete Electronic Withdrawal will be increased to better reflect prevailing rates for such checks and transactions and to discourage customers from making such deficient payments to the Company.

9. The Company is proposing a new charge for a Second Pulse Data Capability to accommodate customers' requests for this service. *See* Grace Dir, Ex. VG-1.0 REV, 7:148-9:180.

Only certain aspects of these proposals are contested, and they will be discussed below.

B. <u>General Rate Design</u>

1. <u>Allocation of Rate Increase</u>

As discussed previously, North Shore proposes to continue to set all its service classifications at cost. Peoples Gas proposes to set S.C. Nos. 4, 6 and 8 at cost and to allocate the remaining revenue requirement among S.C. Nos. 1N, 1H and 2 utilizing the equal percentage of embedded cost (EPEC) method. The EPEC method allocates the remaining revenue requirement in proportion to the embedded costs of service for the three service classifications and the resulting amounts are added to the revenue generated under currently applicable rates for the particular service classification to arrive at the revenue to be provided under proposed rates. Grace Dir., PGL Ex. VG-1.0 REV, 6:123-130; NS Ex. VG-1.0 3REV, 6:111-118.

The EPEC method provides a gradual movement toward full cost recovery for each of the small customer service classifications. It also provides a gradual movement toward equalizing rates of return and ratios of revenue among the small customer service classifications. Grace Dir., PGL Ex. VG-1.0 REV, 7:134-139.

It would appear that all parties support the notion that ideally, all service classifications should support their full cost of service. For various historical and policy reasons, however, the rates of Peoples Gas' small residential service classification have been set below costs. In order to avoid the rate spikes that would attend moving residential service classifications to costs, Peoples Gas has applied a policy of gradualism in the movement toward full cost and the Commission has heretofore endorsed this gradualism in its approval of the EPEC method. *See* Peoples Gas Light and Coke Co., Docket Nos. 91-0586 and 95-0032. No party appears to quarrel with the notion of gradualism being employed in these proceedings. Rather, two witnesses appear to take issue with the rate increase allocations that result from application of the EPEC mechanism. Neither of those parties, or any other party, has proposed a method that is definable and supportable, like the EPEC methodology, although a third party offers a vague alternative to Peoples Gas' proposal. Indeed, the rate increase allocation proposals for Peoples Gas by other parties appear to have been arbitrarily derived and none have been accompanied by analysis which would show the impact of their proposals on customers' bills. In short, only Peoples Gas has provided a reasoned and specific analysis to support its rate increase allocation and only the Companies have shown how their specific rate proposals would affect customers.

Mr. Neil Anderson, on behalf of Vanguard Energy Services ("VES"), proposes to phase in increases for rate classifications to reach cost over a five (5) year period. Mr. Anderson's proposal, however, is devoid of details. While Mr. Anderson characterizes his proposal as a rate design proposal, he does not offer any rates or meaningful rate design proposal for any service classification. His exhibit VES 3, which supports his "rate design proposal", reflects revenue allocations for years 1 through 4 that are consistent with Peoples Gas' EPEC revenue allocation. However, it is unclear how the revenue allocation in year 5 (Exhibit VES 3, line 9) was derived. It should also be noted that the service class revenues in year 5 (Exhibit VES 3, line 9) do not sum to the total company revenues and the total revenue amount is not consistent with any revenue amount proposed by any party in this proceeding. Peoples Gas agrees that it is appropriate to move all service classifications to cost, and it is taking significant steps in this case, including bifurcating S.C. No. 1 into heating and non-heating rates, to move S.C. No. 1 to cost. *See*, Grace Reb., NS-PGL Ex. VG-2.0, 17:367-18:379. However, Mr. Anderson's proposal lacks sufficient detail for the Commission to evaluate and should be rejected.

2. <u>Gas Cost Related Uncollectible Expense</u>

The only issues which are contested concerning Gas Cost Related Uncollectible Expense center from a rate design perspective around how the gas cost related uncollectible expense would be recovered in base rates if Rider UBA is not approved. Staff Witness Mr. Luth is the only party who has taken issue on the record with the Utilities' proposals for the treatment of uncollectible expense if Rider UBA is not adopted. At one point, Mr. Luth had urged that uncollectible expense should be allocated to S.C. Nos. 3 and 4 and Peoples Gas performed an analysis that indicated a portion of bad debt was attributable to S.C. No. 3 and modified the proposals to allocate an appropriate amount to S.C. No. 4. See Amen Reb., NS-PGL RJA-2.0, 14:294-302.

Ms. Grace and Mr. Luth agree in principle that if Rider UBA is not approved, separate base rates will need to be established for sales and transportation customers. Ms. Grace has proposed an approach whereby the Utilities' ECOSS, which already reflects the removal of gas cost related bad debt expense, would establish the base rates for all customers, including transportation customers. The Gas Cost Related Uncollectible Expense would then be added to sales customer's base rates, thereby establishing separate rates in a straightforward and simply manner. Exhibits VG-2.3-PGL and VG-2.3-NSG illustrate this simple methodology which determines how the Utilities' distribution base rates would be affected. Ms. Grace's approach also allocates uncollectible expenses at full costs to each affected service classification. Grace Reb., NS-PGL Ex. VG-2.0, 21:445-447. This is an appropriate approach because it mitigates the impact of such costs on Peoples Gas' S.C. No. 2 which has already been allocated a portion of the rate increase for S.C. Nos. 1N and it is based on cost causation. The assertion that there are errors on Exhibits VG 2.3-PGL and VG-2.3-NSG is simply incorrect. The uncollectible expenses reflected in the referenced exhibits are recovered based on rate class specific historical write-offs, consistent with the approach utilized in Mr. Amen's ECOSS and by Mr. Luth to allocate total uncollectible expense in his ECOSS. Luth, Tr. at 1460:1-21; NS-PGL Luth Cross Ex. 9. Additionally, the Utilities proposed that final credits to transportation customers be based on the gas charge revenues and the gas cost related uncollectible expenses for sales customers as approved by the Commission in this proceeding, rather than any credit based on present rate total gas charge revenues which would inappropriately include a credit arising from transportation customers' own gas charge revenues. Mr. Luth mischaracterizes the proposal above to support his proposal for Account No. 904 expenses. Although, Mr. Amen correctly demonstrated that Account No. 904 expenses is a customer related cost, the Companies have elected at this time to not recover these customer related costs through the customer charge in their gradualism approach of not recovering all customer costs through the customer charge. Grace Sur., NS-PGL Ex. VG-3.0 REV, 13:270-277. Therefore, the determination to recover gas cost related bad debt through the distribution charge is warranted and reasonable.

The Utilities have also established the necessity for a different rate treatment for sales and transportation customers if Rider VBA or Rider WNA is implemented without approval of Rider UBA. Gas cost related uncollectible expense under such circumstances should be made on a per customer, rather than on a per distribution therm basis. Grace Sur., NS-PGL Ex. VG-3.0 REV,16:344-17:357.

Finally, the Utilities have established that if Rider UBA is not approved, gas cost related uncollectible expenses should be recovered entirely through the distribution charge, rather than the customer charge and the distribution charge. Although, Mr. Amen correctly demonstrated that that Account No. 904 expense is a customer related cost, the Companies elected not to recover certain costs through the customer charge in their gradualism approach of not recovering all customer costs through the customer charge. Grace Sur., NS-PGL Ex. VG-3.0 REV,13:270-277. Therefore, the determination to recover gas cost related bad debt through the distribution charge is warranted and reasonable.

3. <u>Other Rate Design Considerations</u>

There are three other considerations that warrant discussion. These are: (1) cost and revenue alignment; (2) bill impact; and (3) sales normalization. The Utilities have proposed that an important objective of rate design is to move customer charges closer to the full cost of providing service to those customers. This involves increasing fixed charges to higher levels, with the application of mitigation measures to effectuate gradualism. It would appear that the Staff is in agreement with this approach to better align costs and revenues. Only Mr. Glahn supports continuation of the practice of recovering a large portion of fixed costs through variable charges. Under the present rates, Peoples Gas recovers 30% of test year fixed costs through fixed charges and North Shore recovers 31%. Under Mr. Glahn's proposals, fixed cost recovery would be reduced to only 28%. By contract, the Utilities' proposals would increase fixed cost recovery for Peoples Gas and North Shore to 45% and 50%, respectively. Grace Reb., NS-PGL Ex. VG-2.0, 23:484-500. Clearly, Mr. Glahn's approach is headed in the wrong direction and does not represent sound and modern regulatory policy.

The Utilities have supported their rate design proposals with impact analyses in Schedule E-9, in very detailed analyses in response to a Staff data request which is summarized in Staff Ex. 7.0, Schedule 7.1 and in PGL Ex. VG-1.6, 1.7, 1.9, 2.4-PGL and NS Ex. VG-1.5, 1.6, 1.8 and 2.4-NSG. Since no other party has offered impact analyses of their rate design proposals, it would be impossible for the Commission to adequately assess these proposals, let alone, approve them, to the extent they are markedly different from those proposals made by the Utilities.

Although over 90% of the Companies' costs are fixed, their proposed rate designs as well as the rate designs proposed by the parties in this proceeding include a volumetric, per therm component – the distribution charge. In order for the Companies to recover their Commission authorized revenues, they need to make assumptions and predictions, about their expected sales. Sales are dependent in part on the number of heating degree days experienced. It is therefore important that the Companies use the most accurate projection of heating degree days available for the period that these rates will be in effect. That is addressed in Section VI. If the

Commission were to approve the much higher and unsupported number of heating degree days as well as the highly volumetric rate design proposed by Mr. Glahn, the Companies likely would not recover the revenue amounts authorized by the Commission. Grace Reb. NS-PGL Ex. 2.0, 25:527-539.

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 classification from "Contract Service" to "Contract Service to Prevent Bypass" so it is more descriptive, allow contract terms in excess of five years for this service classification and make minor editorial changes to the tariff language. Grace Dir., NS Ex. VG-1.0 3REV, 23:498-502.

b. North Shore Service Classification No. 5

The Company's proposal is to set S.C. No. 5 at cost. Therefore, the monthly customer charge was set at $43.00. The monthly demand charge was set at 10.414 cents per therm and the distribution charge at 1.875 cents per therm. Grace Dir., NS Ex. VG-1.0 2REV, 23:505-508. Based on his ECOSS, Staff witness Luth recommended that the Company's proposed monthly customer charge be reduced by 65 cents per month resulting in a monthly customer charge of $42.35. Luth Dir., Staff Ex. 7.0, 24:472-475. The Company accepts Mr. Luth's proposed adjustment as long as it is supported by the ECOSS approved in this proceeding.

c. Peoples Gas Service Classification No. 5

The Company's sole proposal is to make minor editorial changes to the tariff language of SC No. 5. Grace Dir., PGL Ex. VG-1.0 REV, 26:578-579. There has been no other proposal by Staff or by any party to this proceeding.

d. **<u>North Shore Service Classification No. 6</u>**

The Company's sole proposal is to make minor editorial changes to the tariff language of SC No. 6. Grace Dir., NS Ex. VG-1.0 3REV, 24:515-516. There has been no other proposal by Staff or by any party to this proceeding.

e. **<u>Peoples Gas Service Classification No. 6</u>**

The Company's proposed changes are to set SC No. 6 at its embedded cost of service and to eliminate the distinction between heating and non-heating customers. The monthly customer charge was set at $90.00 or 80% of cost. The monthly demand charge was set at cost, 70.956 cents per therm, and the distribution charge at 14.878 cents per therm. Grace Dir., PGL Ex. VG-1.0 REV, 26:584-27:587; Grace Reb., NS-PGL Ex. VG-2.0, 47:1045-48:1063. Staff witness Luth proposed to set S.C. No. 6 at cost although he did not make any specific rate proposals. Grace Sur., NS-PGL Ex VG-3.0, 27:568-572.

f. **<u>Peoples Gas Service Classification No. 8</u>**

The Company proposes to increase charges under SC No. 8 to reflect its embedded cost of service. The monthly customer charge was set at $140.00 and the distribution charge was set at 5.022 cents per therm. Grace Dir., PGL Ex. VG-1.0 REV, 27:601-605. Staff witness Luth proposed to set S.C. No. 8 at cost although he did not make any specific rate proposals. Grace Sur., NS-PGL Ex. VG-3.0 REV, 27:568-572.

2. **<u>Contested Issues</u>**

a. **<u>Peoples Gas Service Classification Nos. 1N and 1H</u>**

The issues pertaining to Service Classification Nos. 1N and 1H apply equally to Peoples Gas and North Shore. Therefore, the following discussion applies to both Companies. As was discussed in Section VII(B)(2)(c) hereof, the Utilities have appropriately demonstrated a basis for bifurcating former Service Classification No. 1 into two service classifications, S.C. No. 1N and S.C. No. 1H. In that earlier section, the Utilities have addressed the reasons the bifurcation proposal is sound. In this section, the Utilities will discuss the specific S.C. No. 1N and S.C. No. 1H charges proposed by other parties, as well as certain S.C. No. 1N and S.C. No. 1H implementation proposals made by Mr. Luth. As discussed earlier in this Section IX, North Shore has proposed to set its S.C. Nos. 1N and 1H at cost while Peoples Gas has proposed to apply the EPEC methodology to allocate costs to S.C. Nos. 1N and 1H. The Utilities propose to establish the S.C. No. 1N charges for Peoples Gas and North Shore at $11.25 and $10.50, respectively. For Peoples Gas, the total monthly embedded fixed costs per customer, with Rider UBA, is $18.14 and the total monthly allocated cost per customer with Rider UBA, derived by applying the EPEC method, is $14.99. While the proposed $11.25 Peoples Gas charge represents 64% of embedded customer costs and 62% of total embedded fixed costs, by applying the EPEC method and only a portion of allocated customer costs, the increase has been limited to $2.25 per month in the interest of gradualism. Moving the charge to total allocated fixed cost would require an additional increase of $3.74 per month, while moving the charge to total embedded fixed cost would require an additional increase of $6.89 per month. For North Shore, the total monthly embedded fixed cost per customer with Rider UBA is $16.18. The proposed $10.50 charge represents 70% of embedded customer costs and 65% of total embedded fixed costs, North Shore has limited the increase to $2.00 per month in the interest of gradualism. Moving the charge to total embedded fixed cost would require an increase of an additional $5.68 per month. Grace Dir., PGL Ex. VG-1.0 REV, 12:249-263; NS Ex. VG-1.0 2REV, 10:208-217.

Peoples Gas is proposing to increase the monthly customer charge for S.C. No. 1H from $9.00 to $19.00 and North Shore would increase S.C. No. 1H from $8.50 to $16.00. The total embedded fixed cost per customer with Rider UBA is $36.27 and the total monthly allocated fixed cost per customer, derived by applying the EPEC method, is $33.80. While the proposed $19.00 charge represents 71% of embedded costs and 52% of total embedded fixed costs, by applying the EPEC method and only a portion of allocated customer costs, Peoples Gas has limited the increase to $10.00 per month in the interest of gradualism. Moving the charge to total allocated fixed costs would require an additional increase of $14.80 per month, while moving the charge to a total embedded fixed cost would require an additional increase of $17.27 per month. If properly aligned, such charges would be recovered entirely through a fixed monthly charge. However, in the interest of rate design continuity, Peoples Gas is proposing to recover all demand costs as well as remaining customer costs through the distribution charge. Similarly, the total embedded fixed cost per customer for North Shore is $29.28. While the proposed $16.00 charge represents 55% of total embedded fixed costs and 79% of embedded customer costs, North Shore has limited the increase to $7.50 per month in the interest of gradualism. Moving the charge to total embedded fixed cost would require an increase of an additional $13.28 per month. If properly aligned, such charges would be entirely recovered through a fixed charge such as the customer charge or a demand charge. However, in the interest of rate design continuity, North Shore is proposing to recover demand costs as well as remaining customer costs through the distribution charge. Grace Dir., PGL Ex. VG-1.0 REV, 13:285-14:302; NS Ex. VG-1.0 3REV, 11:239-12:253.

Mr. Glahn proposes that S.C. No. 1N not be bifurcated and that Peoples Gas decrease its customer charge to $10.50, while retaining the distribution charge in Peoples Gas' currently applicable declining block rate structure. Mr. Glahn's proposed customer charge represents a slight increase in the customer charge from $9.00 to $10.50. Mr. Glahn's S.C. No. 1 proposal is arbitrary and he offers no analysis or justification for it, except casually comparing it to the customer charges of other Utilities. Mr. Glahn has not performed a cost study for the Utilities nor has he provided any analysis of the other utilities rate designs, costs underlying their rates, or any reasoned discussion of how they have been developed or how they specifically compare with Peoples Gas' rates or why such a comparison is relevant. In short, Mr. Glahn's proposal amounts to little more than a "seat of the pants" analysis and should be treated accordingly.

Mr. Glahn's proposal for North Shore's S.C. No. 1 charge is similarly flawed. He proposes no bifurcation of North Shore's S.C. No. 1 charge, establishing it at its current level of $8.50. He offers no analysis to support his customer charge proposal, and he makes no attempt to address the North Shore customer charge in relation to the other components of North Shore's rates, such as the distribution charge. Mr. Glahn's North Shore proposal is at best, superficial and incomplete. In any case, it must be rejected.

Mr. Luth proposes that Peoples Gas slightly increase its proposed S.C. No. 1N in customer charge from $11.50 to $12.00. The Company would not be opposed to this charge as long as any change in the distribution charge is reasonable. He also proposes that the increase in the S.C. No. 1N in customer charge be offset by a decrease in the distribution charge. Mr. Luth also proposes that Peoples Gas' S.C. No. 1H charge be set no higher than the Peoples Gas proposed $19.00 charge. Mr. Luth makes no additional specific recommendations concerning Peoples Gas' S.C. No. 1H distribution charges other than to say that they should not be reduced as long as overall cost are not recovered by rates. As to North Shore, Mr. Luth does not propose any changes to North Shore's S.C. No. 1N.

Only the Utilities have presented proposals for S.C. No. 1N and S.C. No. 1H rates that are comprehensive, detailed, and analytical. The rate proposals of Mr. Glahn are very general and superficial and not based on any cost studies or reasoned analysis. On the other hand, Mr. Luth proposes very reasonable customer charges for Peoples and North Shore S.C. Nos. 1N and 1H. He also reasonably recommends that Peoples Gas' S.C. No. 1N distribution charges be reduced to offset the increase in the customer charge. He makes no recommendation as to distribution rates for the Utilities' S.C. No. 1N. Mr. Luth proposes to reduce the distribution rates for North Shore's S.C. No. 1H as his ECOSS allocates fewer costs to S.C. No. 1H than North Shore's ECOSS. This would also be reasonable. However, his proposal for Peoples Gas S.C. No. 1H distribution charge is too general to warrant any consideration. Since the customer charge proposals of the Utilities do not differ significantly from Staff witness Luth's proposals, approval of the Utilities' comprehensive and well reasoned proposals for rates for S.C. No. 1N and S.C. No. 1H would amount to acceptance of a large part of the Staff proposal.

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

Please see discussion in Section IX(C)(2)(a) of this Initial Brief.

c. Peoples Gas Service Classification No. 2

Peoples Gas proposes to increase the monthly customer charge for S.C. No. 2 customers and to move the charges for meter classes one and two closer to embedded cost for each individual meter class, instead of considering an average of the embedded customer cost for all S.C. No. 2 customers. The proposed monthly customer charges would increase from $15.00 to $21.00 for Meter Class 1 and increase from $22.00 to $60.00 for Meter Class 2. These charges are supported by the ECOSS. Peoples Gas is also proposing to maintain the three declining block distribution charge for SC No. 2 and to allocate 23%, 61% and 16% of the remaining customer, demand and commodity costs to the front, middle and end blocks, respectively. The front block charge has been increased to 35.441 cents, the middle charge has been increased to 13.669 cents per therm and the end block has been decreased to 7.199 cent per therm. The proposed S.C. No. 2 charges exclude the gas cost portion of uncollectible expenses, which would be recovered through Rider UBA. Without Rider UBA, the proposed customer charges would remain the same but the front, middle and end block charges would be 37.695 cents per therm, 14.5339 cents per therm and 7.655 cents per therm, respectively. Grace Dir., PGL Ex. VG-1.0 REV, 22:480-23:511.

Mr. Glahn proposes to increase Peoples Gas' Meter Class 1 customer charge to $27.00 so that it "matches" a charge for one utility and "falls in the midst" of certain other utilities. On the other hand, Mr. Glahn selectively avoids any comparison for Meter Class 2 as Peoples Gas' proposed rate at $60.00 is less than the $70.00 and $90.00 rates charged by those certain other utilities. Mr. Glahn's proposals are based on arbitrary, inapt comparisons and not on sound ratemaking principles.

North Shore proposes to increase the monthly customer charge for S.C. No. 2 customers and move the charges for Meter Classes 1 and 2 closer to the embedded cost for each individual meter class, instead of considering an average of the embedded customer cost for all S.C. No. 2 customers. The proposed monthly customer charges would increase from $15.00 to $17.00 for Meter Class 1 and from $22.00 to $60.00 for Meter Class 2. The proposed customer charges are less than the embedded fixed cost for each meter type and are supported by the ECOSS. North Shore is proposing to also maintain the three declining block S.C. No. 2 distribution charge and allocate 25%, 55% and 20% of the remaining customer demand and commodity cost to the front, middle and end blocks respectively. The front block increases to 23.248 cents per therm, the middle block decreases to 8.716 cents per therm and the end block decreases to 2.769 cents per therm. The proposed S.C. No. 2 rates for North Shore do not include the gas cost portion of uncollectible expense which is recovered through Rider UBA. Without Rider UBA the monthly customer for North Shore would mostly remain the same and the front, middle and end block charges would be 24.175 cents per therm, 9.064 cents per therm and 2.879 cents per therm, respectively. Grace Dir., NS Ex. VG-1.0 3REV, 19:408-20:438.

Mr. Glahn proposes that the North Shore S.C. No. 2 customer charges not be increased. He offers no reasoned analysis or other detail to support his proposal. Thus, Mr. Glahn's S.C. No. 2 recommendations are arbitrary and without merit.

Although Peoples Gas does not agree with Mr. Luth's undefined rate increase methodology for S.C. No. 2, Mr. Luth's rate design proposals are consistent with those proposed by Peoples Gas. As to North Shore's S.C. No. 2, however, there appears to be some divergence of opinion between Mr. Luth and North Shore. Mr. Luth proposes to change North Shore's S.C. No. 2 demand device and transportation administrative charges. Those charges, are cost based and rider specific for North Shore's proposed transportation Riders AGG, SST and P, irrespective of a customer's service classification. It is not appropriate to adjust rider specific charges simply to meet a particular service classification's revenue requirement. If North Shore's S.C. No. 2 needs to be adjusted to meet its revenue requirement, it would be more appropriate to adjust charges that are applicable to the service classification, rather than a charge designated in several riders that applies to several service classifications. Grace Sur., NS-PGL Ex. VG-3.0 REV, 23:499-508.

d. <u>North Shore Service Classification No. 2</u>

Please see Section IX(C)(2)(c) of this Initial Brief.

e. <u>North Shore Service Classification No. 3</u>

North Shore's current S.C. No. 3 is a cost based rate that serves large volume, high load factor customers. Present rates include a monthly two block demand structure which is set at

5,000 therms and over 5,000 therms. North Shore proposes to increase the front block to 10,000 therms to better reflect the higher monthly demand volumes that are representative of this service classification. The minimum, average and maximum monthly demand volumes for this service classification are 19,000 therms, 26,000 therms and 34,000 therms, respectively. The current demand block structure, which current data show is set too low, results in 19% of demand volumes falling within the first block and 81% of demand volumes falling in the end block. This does not allow North Shore to recover its demand costs through a reasonable rate design that accurately reflects the customer profile. To remedy this, at least partially, and to allow a more balanced cost recovery, the Company proposes to increase the front block to 10,000 therms. This would result in 38% of demand volumes falling within the first block and 62% of demand volumes falling within the second block. The revenue from S.C. No. 3 will be set at embedded cost as determined in the ECOSS. This is consistent with the rate treatment in North Shore's last rate case. Grace Dir., NS Ex. VG-1.0 3REV, 21:456-22:471. The demand charge will be set at 80% of cost, with 50% being recovered through the front demand block. That results in about 75% of the total S.C. No. 3 revenue requirement being recovered through the demand charges. The front block (0-10,000 therms) demand charge will be set at 49.065 cents per demand therm and the end block (over 10,000 therms) demand charge will be set at 30.574 cents per demand therm. The monthly customer charge will be set at cost and will be $705.00. The monthly standby service charge will be set at 11 cents per therm of standby demand with the remaining revenue being recovered through the distribution charge, which will be set at .262 cents per therm. *Id*., at 472-480.

Mr. Luth proposes to allocate $236,527 more costs to S.C. No. 3 based on his use of the Average and Peak methodology over the amount that North Shore proposed. While he does not propose any changes to the customer charge, he is proposing to recover 23.1% of the S.C. No. 3 demand costs through the distribution charge resulting in an increase in the proposed S.C. No. 3 distribution charge to 0.46 cents per therm. Applying this proposed rate to the S.C. No. 3 distribution volumes results in distribution charge revenue of $85,246, which is only $36,693 higher than what North Shore proposed. A comparison of this amount to Mr. Luth's additional $236,527 of proposed S.C. No. 3 costs, results in an under-recovery of S.C. No. 3 costs of approximately $199,800.

Mr. Luth failed to account for these additional costs in his revenue adjustments for S.C. No. 3. In addition, North Shore proposed to recover only 80% of demand related costs in the demand charge, with the remaining demand and commodity costs being recovered through the standby service charge and the distribution charge. This proposal is very similar to what Mr. Luth is proposing, but Mr. Luth used a different cost allocation methodology. As Mr. Luth agrees with North Shore's proposed customer charge and derives a demand charge which is similar to that proposed by North Shore, the distribution charge would need to be adjusted to appropriately recover the revenue requirement arising from his ECOSS. The charges would also need to be adjusted to reflect revenues arising from the standby service charge that was corrected. NS-PGL Ex. VG-2.10. Based on that correction, the standby service charge would be reduced from 11 cents per therm to 7 cents per therm. Even with the proposed changes, all charges would need to be supported by the final ECOSS arising from this proceeding. Grace Reb., NS-PGL Ex. VG-2.0, 46:1019-47:1042.

Mr. Luth does not address North Shore's S.C. No. 3 in his Rebuttal Testimony although Staff Ex. 19.0, Schedule 19.1-NS accompanying that testimony reflects different demand and distribution charges than those proposed in his Direct Testimony and in data responses.

Otherwise, Mr. Luth's customer charge proposal approximates that proposed by North Shore. Grace Sur., NS-PGL Ex. VG-3.0 REV, 26:560-565. Given the lack of clarity attending Mr. Luth's proposals for North Shore's S.C. No. 3 charges, the Commission should adopt the Company's proposal which appears not to differ greatly from Mr. Luth's recommendations.

f. <u>Peoples Gas Service Classification No. 4</u>

The Company's current S.C. No. 3 is a cost based rate that was designed to serve large volume, low load factor customers. The Company's current S.C. No. 4 is a cost based rate that was designed to serve large volume, high load factor customers. In the Company's last rate case the average load factors for S.C. No. 3 and S.C. No. 4 were 42% and 75%, respectively. Currently, these load factors are 37% and 51%, respectively.

As the difference in average load factors has significantly narrowed between the two service classifications, it is no longer necessary to provide service under two separate large volume service classifications. Combining these two service classifications under S.C. No. 4, Large Volume Demand Service, is also supported by the Company's ECOSS which demonstrates that on a per demand therm basis, there is very little difference in costs. The revenue from S.C. No. 4 will be set at embedded cost for S.C. Nos. 3 and 4 combined as determined in the ECOSS. This is consistent with the rate treatment in the Company's last rate case. The monthly customer charge will be set at cost and will be $565.00. The demand charge will be set at 80% of cost, with 70% being recovered through the front demand block. That results in about 59% of the total S.C. No. 4 revenue requirement being recovered through the demand charges. The monthly standby service charge will be set at 24 cents per therm of standby demand with the remaining revenue being recovered through the distribution charge, which will be set at 1.211 cents per therm. The front block (0-7,500 therms) demand charge is

50.609 cents per demand therm and the end block (over 7,500 therms) demand charge is 40.163 cents per demand therm.

Currently, S.C. No. 3 customers are not required to have a daily demand measurement device to determine billing demand although S.C. No. 4 customers are required to have such a device. As the Company is proposing to increase the amount of the revenue requirement being recovered through the demand charge, these customers will be required to have a daily demand device to determine billing demand. This should have a minimal impact on most S.C. No. 3 customers as about 90% of the current customers already have such devices installed. For those customers who do not have a daily demand device installed, until such device can be installed, the billing demand will be calculated using the same methodology currently used to make such a determination for transportation customers. The sales customers' standby demand will be the same as their billing demand and the Rider SST customers' standby demand will be their selected standby demand. The Company would propose the same charges as those with Rider UBA. Grace Dir., PGL Ex. VG-1.0 REV, 24:530-26:565.

Using his ECOSS, Mr. Luth's proposal results in only 33% of demand costs being recovered through the demand charge. This shifts 60% of demand cost recovery through a volumetric distribution charge with 7% of demand costs being recovered through the standby service charge. Mr. Luth's ECOSS shows volumetric commodity costs for Peoples Gas' S.C. No. 4 of $804,826 while his proposal results in recovery of $9.1 million or 1,119% over the amount that should be recovered on a volumetric basis. Mr. Luth expresses concern about Peoples Gas' increased demand charge for former S.C. No. 3 customers but overlooks the impact that his higher distribution charge would have on all customers. Mr. Luth's proposal would more than triple the distribution charge for current Peoples Gas' S.C. No. 4 customers.

Mr. Luth's proposed rate designs, which are not based on sound ratemaking principals, would be uneconomical to customers in this service classification and may induce some to switch to S.C. No. 2 or bypass Peoples Gas' system. Conversely, Peoples Gas' proposals are reasonable and based on sound ratemaking principals.

g. **<u>Peoples Gas Service Classification No. 7</u>**

The Company's current S.C. No. 7, Contract Service, is available to any customer for whom bypass of the Company's gas distribution system is economically feasible and practical. Grace Dir., PGL Ex. VG-1.0REF, 27:593-595. The Company proposes to change the description of this services classification from "Contract Service" to "Contract Service to Prevent Bypass" to make it more descriptive and allow for a longer term contract in response to customer requests. *Id.* at 27:595-598. No parties have contested those issues.

Mr. Glahn's proposal to allocate costs to S.C. No. 7 is flawed for several reasons, however. First, is it rooted in his assumption that Peoples Gas "assumes that the costs to service this group of customers has not increased since 1995." Glahn Dir., GCI Ex. 3.0 REV, 13:16-17. Peoples Gas' present tariff limits contract terms for customers served under this service classification to five years. As a result contracts which may have been in place since Peoples Gas' last rate case over eleven years ago have been renegotiated based on the proper cost considerations. Peoples Gas' allocation has been performed against the backdrop of the circumstances presently in place in respect of the contracts, *i.e.*, data which has changed since 1996. Mr. Glahn has not explained how any rate increase he might impute into rate design could be factored into the binding contracts that are currently in effect and that may expire up to five years from the effective date of Peoples Gas' increase. Accordingly, Witness Glahn's proposed allocations for S.C. No. 7 should be rejected by the Commission and Peoples Gas' proposed changes should be approved.

D. **<u>Tariffs – Other Tariff Issues</u>**

The Utilities propose several changes in a variety of tariffs for various reasons. None of the intervenors have opposed any of the changes to the Tariff issues delineated in this section. However, Staff has objected to language in some of the Tariffs, of which all but two of the objections have been resolved.

1. **<u>Rider 2, Factor TS</u>**

The Utilities propose to revise Rider 2 to reflect the applicability and renaming of applicable transportation riders. The Companies also propose to eliminate Factor TS, Transition Surcharge and refund or recover any dollars awaiting recovery or refund through Factor NCGC, Non-Commodity Gas Charge. Staff Witnesses Dan Kahle and Cheri Harden support the Companies' proposal to roll Factor TS balances into their non-commodity gas charges. Harden Dir., Staff Ex. 9.0, 24:516-518; Harden Reb., Staff Ex. No. 21.0, 2:23-3:27. Given that no other parties have addressed this matter, the Companies' proposal is uncontested.

2. **Charge for Dishonored Checks and/or <u>Incomplete Electronic Withdrawal</u>**

The Companies propose to increase their charge for dishonored checks and incomplete electronic withdrawals from $10.00 to $25.00 to better reflect prevailing rates for such checks and transactions and to discourage customers from making deficient payments to the Company. Grace Dir., PGL Ex. VG-1.0 REV, 32:709-711. The Commission has approved an increased charge of $25.00 for Mid American Energy in Docket No. 99-0534. *Id.* at 716-717. The Mid American Order stated that the increase "would serve to discourage payment with checks that are not valid" and "that revenues from this charge will serve to reduce the rates of those customers who make valid payments." *Re Mid American Energy Company*, 2000 WL 3444650 (Ill.C.C. July 11, 2000) (Docket No. 99-0534). In these proceedings, as in Mid American Energy, revenue from the Utilities' charge will offset the increase in base rates in this proceeding. Grace Dir., PGL Ex. VG-1.0, 32:711-718. Staff Witness Cheri Harden is supportive of the Companies' proposal. Harden Dir., Staff Ex. 9.0, 11:226. Witness Glahn opposes the increase in the charge for dishonored checks and incomplete electronic withdrawals, basing his opposition on a lack of a cost study. Glahn Reb., GCI Ex. 6.0 REV, 15:354-363; Glahn Dir., GCI Ex. 3.0 REV, 35:2-8. This Commission was clear when it approved a similar increase in the Mid American Order (Docket No. 99-0534) to better reflect prevailing rates and to discourage customers from making deficient payments to the company. As Staff agrees, the Commission should approve the increase for dishonored checks and incomplete electronic withdrawals.

3. <u>Rider 4, Extension of Mains</u>

The Utilities propose changes to Rider 4 to clarify language and to address certain practices and customer preferences. The basic structure of Rider 4 is unchanged. The Companies are responsible for the costs associated with certain main installations as Part 500 of Commission's Rules provides. However, when, for example, a customer requests that the Companies install a main in a different location than is required to provide service, the customer would bear the incremental costs associated with meeting the customer's preferences. Grace Dir., PGL, Ex. VG-1.0 REV, 36:795-802. Staff Witness Cheri Harden disagreed with the language of Rider 4 regarding "return" and testified that the proposed language should not be approved for Rider 4. Harden Reb., Staff Ex. No. 21.0, 4:92-5:98. The Utilities have agreed to concede to the objection of Staff Witness Harden and remove the proposed language regarding "return". Grace Sur., NS-PGL Ex. VG-3.0 REV, 29:627-628. No other parties addressed this matter and therefore, this matter is not contested.

4. Rider 5, Gas Service Pipe

The Utilities also propose to revise Rider 5 to clarify language and to address certain practices and customer preferences. The Utilities proposed to reduce the free main extension shown in Rider 5 from 100 feet to 60 feet consistent with an agreement between Staff and parties related to question raised by the Commission when it initiated Docket No. 03-0767. Grace Dir., PGL Ex. VG-1.0 REV, 36:804-37:811. As with Rider 4, Staff Witness Cheri Harden disagreed with the language of Rider 5 regarding “return” and recommended the language not be approved by the Commission. Harden Reb., Staff Ex. No. 21, 6:133-135. As with Rider 4, the Utilities agreed to concede to the objection of Staff Witness Harden and remove the proposed language regarding “return”. Grace Sur., NS-PGL Ex. VG-3.0 REV, 29:627-628. No other parties addressed this matter and therefore, it is not contested.

5. Rider 8, Heating Value of Gas Supplied

The Companies propose to revise Rider 8 to reflect the applicability of the rider based on the elimination and renaming of transportation riders and to make a minor grammatical change. The revisions also specify that the Utilities will make filings only when the heating value factor changes, rather than file every month. Grace Dir., PGL Ex. VG-1.0 REV, 37:821-824. Staff Witness Harden opposes the Utilities’ change regarding monthly filing requirement believing there would be no assurance that the Utilities are reviewing heating value factors. Harden Reb., ICC Staff Ex. No. 21.0, 8:175-179. The Utilities review heating values on an ongoing basis in the due course of their business, not simply on a monthly basis. The heating value factor often remains the same for two or more consecutive months, and a filing is only needed when the factor changes. Grace, Dir., PGL Ex. VG-1.0 REV, 37:821-826. Therefore, it is appropriate that filings be made only when there is such a change.

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

Staff Witness Harden agrees with the Companies proposed elimination of Riders 13, 14, 15, CCA, and LCP. Harden Dir., Staff Ex. No. 9.0, 18:392-397, 19:409-415, 19:425-426, 20:445-447, 21:461-463. No other parties addressed these matters, which leaves them uncontested.

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

Staff Witness Harden is in agreement with the changes to Riders 1, 3, 10 and 11, and no other parties addressed these matters.

a. Rider 1, Additional Charges for Taxes and Customer Charge Adjustments

Peoples Gas proposes to revise Rider 1 to clarify language and to incorporate the language from Riders 15 and CCA, which are being eliminated. Rider 15 provides for taxes on the use of compressed natural gas while Rider CCA provides for charges arising from the Energy Assistance Act of 1989 and the Renewable Energy, Energy Efficiency and Coal Resources Development Law of 1997. Grace Dir., PGL Ex. VG-1.0 REV, 35:763-767. Staff Witness Harden concurs with the Companies' modifications. Harden Dir. Staff Ex. No. 9.0, 23:496-504.

b. Rider 3, Budget Plan of Payment

The Companies propose to revise the language of Rider 3 to make it more consistent with the Companies' current budget plan. Grace Dir., PGL Ex. VG-1.0 REV, 36:789-793; Grace Dir. NS Ex. VG-1.0 3REV, 32:696-701. Staff witness Ms. Harden finds the changes acceptable. Harden Dir., Staff Ex. No. 9.0, 26:556-558.

c. Rider 10, Controlled Attachment Plan

The Companies propose to revise Rider 10 to reflect the applicability of the rider based on the elimination and renaming of transportation riders and to make the language more understandable. Grace Dir., PGL Ex. VG-1.0 REV, 34:740-742 and 38:833-835. Staff agrees with the proposed changes in Rider 10. Harden Dir., Staff Ex. No. 9.0, 31:692-32:695.

d. Rider 11, Adjustment of Incremental Costs of Environmental Activities

The Companies made minor editorial changes and revised Rider 11, as required by the Commission's order in Docket No. 06-0540 to reflect the Companies' change to a calendar year for its fiscal year. Grace Dir., PGL Ex. VG-1.0 REV, 34:745-747 and 38:838-840. Staff agrees with the proposed changes in Rider 11. Harden Dir., Staff Ex. No. 9.0, 32:710-33:715.

X. TRANSPORTATION ISSUES

A. Overview

Peoples Gas and North Shore each proposed substantial revisions to its existing transportation tariffs. Zack Dir., PGL Ex. TZ-1.0 2Rev.; Zack Dir., NS Ex. TZ-1.0 REV Each Utility's existing transportation tariffs consist of two separate programs – a large volume transportation program and a small volume transportation program.

Each Utility first made gas transportation service available to large volume customers in the mid-1980's. The details of each Utility's large volume transportation were largely put in place in each Utility's last rate case – Docket No. 95-0031 for North Shore and Docket No. 95-0032 for Peoples Gas. Each Utility's existing large volume transportation program is set forth in Riders FST (Full Standby Transportation), SST (Selected Standby Transportation), LST (Large Volume Selected Standby Transportation), TB (Transportation Balancing) and P (Pooling). The first three riders describe the customer's service level. Rider FST is a full standby service available to all customers except those served under S.C. No. 1. Rider SST is a partial standby service available to S.C. Nos. 2 and 8 customers on Peoples Gas and to S.C. No. 2 customers on North Shore. Rider LST is a partial standby service that is very similar to Rider SST, available to S.C. Nos. 3 and 4 customers on Peoples Gas and to S.C. No. 3 customers on North Shore. Customers served under Rider LST for each Utility have fully unbundled base rates, and Rider LST reflects this rate design. Rider TB is the required balancing service used by Rider LST customers who elect 0% standby service. Rider P is the aggregation or pooling service that the suppliers who sells gas to large volume transportation customers purchase. Each large volume transportation customer receives an Allowable Bank ("AB") that allows it to balance differences between the quantities of gas actually delivered by its gas supplier to the Utilities and the quantities of gas actually consumed by that customer.

Each Utility's current small volume transportation program is set forth in Rider SVT (Small Volume Transportation) and Rider AGG (Aggregation). The small volume transportation customer takes service under Rider SVT, and the supplier who sells gas to that customer purchases an aggregation service under Rider AGG. Peoples Gas' small volume program originally was introduced in 1997 as a pilot program for small volume General Service customers. In 2002, its small volume transportation program was made permanent and expanded to include Small Residential Service customers and North Shore implemented a substantially identical small volume program. Under each Utility's small volume transportation program, the small volume supplier receives a proportionate share of each Utility's storage capabilities based on the requirements of that suppliers' customers and on how the Utility uses its storage capabilities, subject to the monthly storage injection and withdrawal parameters provided by each Utility to these suppliers and subject to the 10% daily tolerance that each Utility provides to these suppliers for daily deliveries. In addition (unlike the large volume program), each Utility takes responsibility for forecasting small volume delivery requirements correctly.

In these proceedings, Peoples Gas originally proposed the expansion of Rider SVT (and renaming it CFY), the elimination of Rider FST, changes to Rider SST, the merging of Rider LST into Rider SST, and changes to Rider TB and Rider P. Zack Dir., PGL Ex. TZ-1.0 2REV, 1:17-20. North Shore originally proposed the expansion of Rider SVT (and renaming it CFY), the elimination of Rider FST, changes to Rider SST, the merging of Rider LST into Rider SST, changes to Rider P and the elimination of Rider TB. Zack Dir., NS Ex. TZ-1.0, 1:18-21. However, the underlying reason for each Utility's proposal was the same: the storage and standby rights of each Utility's transportation customers need to be shaped to be consistent with each Utility's individual gas supply portfolio, and each Utility needs to have an annual mechanism to adjust those rights as its individual gas supply portfolio changes. Zack Dir., PGL Ex. TZ-1.0 REV, 3:49-52; NS Ex. TZ-1.0, 3:50-53.

A number of intervenors opposed many of the changes sought by the Utilities. Staff recommended that the Commission accept many of the changes sought by the Utilities, but it recommended that the Commission reject some of them. There were some proposals of the Utilities to which no party has objected, and those issues will be summarized briefly below.

B. Uncontested Issues

1. Demand Diversity Factor

Under its current rates Peoples Gas' demand Diversity Factor is 0.50. Zack Dir., PGL Ex. TZ-1.0 2REV, 21:482-484. Peoples Gas has proposed to set its Diversity Factor to 0.87. Zack Dir., PGL Ex. TZ-1.0 2REV, 21:486-22:489. Neither any intervenor nor Staff has filed any evidence in opposition to this proposal. Under its current rates North Shore's demand Diversity Factor is 0.50. Zack Dir., NS Ex. TZ-1.0, 20:456-457. North Shore's has proposed to set its

Diversity Factor to 0.75. Zack Dir., NS Ex. TZ-1.0, 20:459-462. Neither any intervenor nor Staff has filed any evidence or otherwise submitted any statement in opposition to this proposal. Therefore, the Commission should approve a 0.87 Diversity Factor for Peoples Gas and a 0.75 Diversity Factor for North Shore.

2. Daily Demand Measurement Device Charge

Peoples Gas proposed to change its Daily Demand Measurement Device Charge from a range of three charges, depending on the type of meter, to a single charge of $28.00 per month. Zack Dir., PGL Ex. TZ-1.0 2REV, 48:1100-1102; PGL Ex. TZ-1.17. Neither any intervenor nor Staff has filed any evidence in opposition to this proposal. North Shore proposed to change its Daily Demand Measurement Device Charge from a range of three charges, depending on the type of meter, to a single charge of $34.00 per month. Zack Dir., NS Ex. TZ-1.0, 46:1047-1049; NS Ex. TZ-1.17. Neither any intervenor nor Staff has filed any evidence in opposition to this proposal. Therefore, the Commission should approve a Daily Demand Measurement Device Charge of $28.00 per month for Peoples Gas and a Daily Demand Measurement Device Charge of $34.00 per month for North Shore.

3. Elimination of Rider TB (NS)

North Shore proposed to eliminate Rider TB. Zack Dir., NS Ex. TZ-1.0, 17:515. Neither any intervenor nor Staff has filed any evidence in opposition to this proposal. Therefore, the Commission should approve North Shore's elimination of Rider TB.

4. Revised Calculation of Average Monthly Index Price

North Shore proposed to change its calculation of the Average Monthly Index Price ("AMIP") from an average of weekly indices to an average of daily indices. Zack Dir., NS Ex. TZ-1.0, 45:1018-1023. Peoples Gas proposed to make the same change to its calculation of the AMIP. Zack Dir., PGL Ex. TZ-1.0 2REV, 46:1051-1056. Neither any intervenor nor Staff has filed any evidence in opposition to this proposal. Therefore, the Commission should approve each Utility's proposed change to its calculation of AMIP.

5. <u>Administrative Charges for Rider SST and Rider P</u>

Peoples Gas proposed that the monthly administrative charge for Rider SST be reduced to $23.00 and that the monthly administrative charge for Rider P be set at $18.00. Zack Dir., PGL Ex. TZ-1.6, Page 1 of 2. North Shore proposed that the monthly administrative charge for Rider SST be reduced to $21.00 and that the monthly administrative charge for Rider P be set at $13.00. Zack Dir., NS Ex. TZ-1.6, Page 1 of 2. Vanguard complained that these rates should be set only to recover costs incurred. Vanguard Ex. 1.0, 18:394-405; Vanguard Ex. 2.0, 18:394-405. In rebuttal Mr. Zack testified that the Utilities did not object to setting the Rider SST charge at $23.16 for Peoples Gas and $21.48 for North Shore and the Rider P charge at $17.55 for Peoples Gas and $12.61 for North Shore. Zack Reb., NS-PGL Ex. TZ-2.0, 45:993-996. No other party expressed any opposition to the revised administrative charges reflected in Mr. Zack's rebuttal testimony.

In light of the Utilities' proposals to retain a form of Rider FST, the Utilities recalculated these monthly administrative charges, and the recalculated charges would yield a Rider SST charge of $11.24 for Peoples Gas and a Rider SST charge of $8.94 for North Shore, and a Rider P charge of $8.36 for Peoples Gas and a Rider P charge of $4.95 for North Shore. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 6:117-118; NS-PGL Ex. TZ-3.1. The Utilities presume that because no party objected to the administrative charges reflected in Mr. Zack's direct testimony, no party would object to the even lower charges reflected in Mr. Zack's surrebuttal testimony.

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

Consistent with the requirements of Rider SVT, the Utilities' practice has been to hold any CFY customer enrollment request if there is not an actual reading of a customer's meter in over 120 days. The Retail Gas Suppppliers ("RGS") proposed that this requirement be eliminated. RGS Ex. 1.0, 42. The Utilities have accepted RGS' position on this issue, so it no longer is a contested issue. Zack Reb., NS-PGL Ex. TZ-2.0, 58:1295-1299.

7. Meter Reading[27]

Staff initially raised a concern with the number of consecutively unread meters, but Staff, in rebuttal testimony, expressed general satisfaction with Peoples Gas' responses in testimony, and suggested that Peoples Gas should provide quarterly updates (within 30 days after the end of each quarter), to the Director of the Energy Division and the Director of the Consumer Services Division of Staff, summarizing the number of consecutively unread meters without a reading for more than six months, or three months in the case of ERTed meters. Lounsberry Reb., Staff Ex. 23.0, 20:382- 23:443, 25:485 – 26:499. Peoples Gas agreed to provide these reports. Doerk Sur., NS-PGL Ex. ED-3.0, 3:64 – 4:69. No party opposed the agreement to provide the reports.

8. Automatic Meter Reading

Vanguard and Multiut argued that the availability of automatic meter reading ("AMR") addressed the Utilities' concerns about meter reading for Rider FST customers. Vanguard Ex. 1.0, 11-12; Vanguard Ex. 2.0, 11-12; Multiut Ex. 1.0, 6. The Utilities responded that AMR did not alleviate the larger issue of the need to better align customer usage with daily injection and withdrawal rights. NS-PGL Ex. TZ-2.0, 6:123-130. However, in light of the Utilities'

[27] This subsection concerns sales customers, not transportation customers. Its inclusion here is an artifact resulting from the negotiation of the joint outline for these briefs.

withdrawal of their proposed to require daily metering of Rider FST customer usage, *infra*, Section X.C.1., this argument is moot.

9. Billing Demand Determination

Constellation NewEnergy – Gas Divison ("CNE-Gas") proposed that the Utilities be compelled to change their method of determining a customer's Billing Demand from being the customer's highest daily demand in therms from December to February of the most recent 12 month period to the arithmetic average of the customer's highest five daily demands therms from December to February of the most recent 12 month period. CNE-Gas Ex. 1.0, 25:551-554. The Utilities originally opposed CNE-Gas' proposal. Zack Reb., NS-PGL Ex. TZ-2.0, 46:1006-1011. However, they also indicated they could accept a compromise revision to the Billing Demand definition based on certain alternate tariff language proposed by CNE-Gas. Zack Reb., NS-PGL Ex. TZ-2.0, 46:1011-47:1032. In rebuttal testimony CNE-Gas advised that it was willing to accept the Utilities' compromise language on this issue. CNE-Gas Ex. 2.0, 34:716-720.

Neither any other intervenor nor Staff has filed any testimony in connection with the proper determination of Billing Demand. While the compromise provision proposed by the Utilities to deal with the Billing Demand issue is the first choice of neither the Utilities nor CNE-Gas, it is acceptable to both of them and therefore the Commission should accept the compromise as a resolution of the issue.

10. Imbalance Trading

In its original filing Peoples Gas proposed to expand the circumstances under which imbalance trades would be allowed. Zack Dir., PGL Ex. TZ-1.0 2REV, 49:1108-1123. It proposed that trades be allowed for any movement of gas to or from a customer's Allowable Bank for any reason, as long as (1) they net to zero within Peoples Gas' system; (2) they cannot reduce bank balances below minimum bank requirements or increase them above maximum bank requirements; (3) they are confirmed by both parties; (4) they are done via PEGASys™; and (5) they may not eliminate daily balance penalties. North Shore originally proposed identical permissible imbalance trading provisions. Zack Dir., NS Ex. TZ-1.0, 46:1052-47:1070. In rebuttal, Mr. Zack clarified that an additional condition of a permissible trade was that a customer could not trade gas in excess of the amount of its imbalance. Zack Reb., NS-PGL Ex. TZ-2.0, 65:1447-1453. No party objected to either of the Utilities' proposals concerning imbalance trading, and the Commission should permit these proposals to go into effect.

C. Large Volume Transportation Program

1. Rider FST

Each Utility originally proposed to eliminate its Rider FST, with existing FST customers to take transportation service, at their election, either under a more inclusive Rider CFY or under a modified Rider SST, or to take retail sales service. Zack Dir., PGL Ex. TZ-1.0 2REV; Zack Dir., NS Ex. TZ-1.0 REV. The reasons for their proposal to eliminate Rider FST are that the actual operation of the program results in inefficient meter reading procedures and more importantly it expends assets beyond those reasonably appropriate for the provision of the service. Zack Dir., PGL Ex. TZ-1.0 REV, 33:745-747; NS Ex. TZ-1.0, 31:719-721. The Utilities each proposed the elimination of Rider FST to more closely match its rights with respect to storage injections and withdrawals with the rights exercised by their transportation customers. Zack Dir., PGL Ex. TZ-1.0 2REV, 33:758-34:773; NS Ex. TZ-1.0, 33:733-747. With respect to Rider SST, the Utilities each also proposed limits on customer withdrawals and injections from a customer's AB to reflect, to some extent, the limits on withdrawals and injections within which each Utility has to operate in connection with its storage assets. Zack Dir., PGL Ex. TZ-1.0 2REV, 38:860-862; NS Ex. TZ-1.0, 36:830-832. Peoples Gas also proposed that its transportation customers taking service under Rider SST be required to meet specific storage inventory requirements by having their AB at least 70% full on November 30 and no more than 35% full on March 31 of each year. Zack Dir., PGL Ex. TZ-1.0 2REV, 42:951-963. Correspondingly, North Shore proposed that its transportation customers taking service under Rider SST be required to meet specific storage inventory requirements by having their AB at least 85% full on November 30 and no more than 24% full on March 31 of each year. Zack Dir., NS Ex. TZ-1.0, 40:921-41:933. The differing levels of storage inventory requirements proposed by the two Utilities were based on each Utility's own storage rights and assets, and the restrictions to which each Utility is subject with respect to those storage rights and assets.

The Illinois Industrial Energy Consumers ("IIEC"), CNE-Gas, VES and Multiut objected to the Utilities' proposals. IIEC/CNE/VES Jt. Ex. 1.0, 15:13-21:21; CNE-Gas Ex. 1.0, 27:594-599; Vanguard Ex. 1.0, *passim*; Multiut Ex. 1.0, 6:122-127. Staff objected to some, but not all, of the Utilities' proposals. ICC Staff Ex. 24.0, 1-2:19-24; 9-10:171-201; 12:229-237. The opponents of the Utilities' proposals cited a number of reasons for their opposition. They liked the Rider FST program as is, and saw no reason to change it. They believed that the requirement to meter the consumption of SST customers on a daily basis would impose significant unnecessary costs on those customers for metering equipment and telephone equipment and charges. The Utilities dispute these beliefs. Zack Reb., NS-PGL Ex. TZ-2.0, 10:200-202. The opponents objected to the storage injection and withdrawal limitations, and the cycling requirements for transportation customer storage gas inventory that formed the basis of the Utilities' original proposals. They also wanted the Utilities' proposals to limit injections and withdrawals from storage by transportation customers to be relaxed on non-critical days. IIEC/CNE/VES Jt. Ex. 1, 3:1-2. Staff, while generally siding with the opponents of the Utilities' proposals, found the Utilities' transportation customer cycling requirement proposal to be acceptable. ICC Staff Ex. 24.0, 12:229-237.

In response to the criticisms of their original proposals, the Utilities proposed to retain an alternative form of Rider FST. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 4:85-87. Under their revised proposal, a customer's daily nominations under Rider FST would be capped at the customer's average daily use in the comparable month in the prior year plus 0.67% (20% divided by 30) of the customer's AB, and with the customer being obligated to operate within the framework of the Utilities' end of season restrictions on storage balances. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 5:104-111. In response to criticism the Utilities also modified their proposed changes to Rider SST. Zack Sur., NS-PGL Ex. TZ-3.0 REV,9-10:180-217. In lieu of their original proposals for daily injection and withdrawal limits for SST customers, the Utilities proposed revised Riders SST that would limit a customer's monthly injections to 20% of AB converted to a daily injection limit, but they would not place additional daily limits on a customer's withdrawals from AB from limits currently in effect. *Id*., at 185-186. The revised Riders SST would have new daily and monthly injection provisions while retaining the existing daily and monthly withdrawal provisions. However, both FST and SST customers would have the identical end of season storage inventory requirements on the applicable Utility.

The Utilities' revised proposals regarding Riders FST and SST are based on suggestions made by Vanguard (Vanguard Ex. 2.0, 9:200-203), and Staff (Staff Ex. 24.0, 12:229-237) to address the concerns of transportation customers while addressing the most problematic aspects of the Utilities' current transportation programs. While the compromise provisions proposed by the Utilities regarding the revision of Riders FST and SST are not the first choice of any party to this case, they represent a reasonable resolution of the issues. Therefore the Commission should accept the Utilities' revised proposals regarding Riders FST and SST.

2. <u>Rider SST</u>

Please see discussion under Section X(D)(1), *supra*.

3. <u>Daily Metering Requirements</u>

The Utilities proposed to maintain their requirement that Rider SST customers would be required to have their gas consumption metered on a daily basis and Rider CFY customers need not have daily metering. Consequently, under the Utilities' original proposal to eliminate Riders FST, customers moving to Rider SST would be required to have daily metering, but FST customers moving to Rider CFY would not be required to have daily metering. Zack Dir., PGL Ex. TZ-1.0 2REV, 35:797-799; NS Ex. TZ-1.0, 34:769-773. Staff opposed the imposition of this daily metering requirement on FST customers moving to Rider SST service. ICC Staff Ex. 24.0, 15:283. CNE-Gas, Vanguard and Multiut also opposed the imposition of this daily metering requirement on FST customers. CNE-Gas Ex. 2.0, 19:399-403; Vanguard Ex. 3.0, 7:140-145; Multiut Ex. 2.0, 5:69-73.

The Utilities' revised proposals regarding Riders FST and SST, discussed under X.D.1., above, essentially moot this issue. Customers currently being served under Rider FST will be able to continue to receive service under that Rider without having to have their consumption metered daily. Customers currently being served under Rider SST would continue to be required to have their consumption metered daily, and any customer electing to be served under Rider SST in the future would be required to have its consumption metered daily. In essence, the Utilities are no longer proposing any changes to their existing tariffs regarding daily metering requirements, and no party has argued that their existing tariffs regarding daily metering requirements are unjust or unreasonable.

4. Injection, Withdrawal and Cycling Requirements

Please see discussion under Section X(D)(1), *supra*.

5. Unbundled Storage Bank ("USB")

IIEC, CNE Gas and VES ("USB advocates"), each of which is a large volume transporter or a gas supplier serving such customers on the Utilities' systems, jointly proposed that the Utilities be compelled to offer to transportation customers a base rate storage service that is unbundled from the AB which is supported by pipeline and company-owned service, with a cost-based unbundled storage bank ("USB") charge. IIEC/CNE/VES Jt. Ex. 1, 2:16-24. The USB advocates originally proposed that the USB charge be 0.60 cents per therm of storage capacity per month for Peoples Gas and 0.23 cents per therm of storage capacity per month for North Shore, with Peoples Gas' transportation customers receiving 20 times the customer's Maximum Daily Quantity (MDQ) of unbundled storage, and with North Shore's transportation customers receiving 6 times the customer's MDQ of unbundled storage. *Id*., at 2:20-24. They later revised the proposed USB charge to both Peoples Gas' and North Shore's transportation customers to a single rate of 0.71 cents per therm of storage capacity per month. IIEC/CNE/VES Jt. Ex. 2, 14:293-295, 14:319-321, and Schedule 2. The stated rationale for their proposal is that Peoples Gas owns the Manlove gas storage field, and that this field could support USB service. IIEC/CNE/VES Jt. Ex. 1, 7:6-7. However, they also claim that the Utilities could provide the USB service more economically by utilizing other parts of their systems as well as Manlove. IIEC/CNE/VES Jt. Ex. 2, 9:176-183. The Utilities believe that this latter claim substantially undermines the stated rationale for the USB proposal.

The Utilities oppose being compelled to offer the proposed USB. Zack Reb., NS-PGL Ex. TZ-2.0, 14-23:300-508; Zack Sur., NS-PGL Ex. TZ-3.0 REV, 21-25:449-553. The proposal would provide USB customers with daily injection and withdrawal rights vastly exceeding the capabilities of Manlove, which would necessarily mean that the Utilities' sales customers would subsidize the USB service. *Id*. The USB proposal would make it more difficult for the Utilities to manage their systems for the benefit of all their customers. The USB advocates' revised USB proposal ignores the fact that the Utilities are separate from each other, have different gas storage rights and are separately regulated by the Commission. Moreover, North Shore does not own a storage field, so, it does not have a base rate storage asset to nbundled. Staff also opposes the USB proposal, essentially for the reason that Manlove Field is Peoples Gas' lowest cost storage resource, and Staff believes that the storage available to transport customers should reflect the availability (and the cost) of all storage resources that the Utilities own or lease, not just the storage that has the lowest cost. ICC Staff Ex. 24.0, 13-14:255-266. The Commission should reject the USB proposal, for the reasons outlined by the Utilities and by Staff.

6. Rider P-Pooling

a. Pool size limits

In response to supplier requests, the Utilities each proposed to increase the maximum pool size under Rider P from 150 to 200 accounts. Zack Dir., NS Ex. TZ-1.0, 43:986-987; PGL Ex. TZ-1.0 2REV, 45:1020-1021. In response, Vanguard proposed that the pool size limit be increased further, to 300 accounts. Vanguard Ex. 1.0, 5:103 – 6:112; Vanguard Ex. 2.0, 5:102 – 6:111[28]. CNE proposed that the pool size limit be eliminated entirely. CNE-Gas Ex. 1.0, 18:384-386. Staff also believes that the pool size limit should be eliminated entirely. Rearden Reb., Staff Ex. 24.0, 21:409-410.

[28] Ironically, in Nicor Gas Company's most recent rate case, Vanguard argued that Nicor Gas should increase its pool size limit from 50 accounts to 150 accounts, using the existence of Peoples Gas' Rider P pool size limit of 150 accounts as support for its argument. *In Re Northern Illinois Gas Company d/b/a Nicor Gas Company*, ICC Docket No. 04-0779, Order dated September 20, 2005, at 174. Lacking the existence of a similarly convenient example in these proceedings, Vanguard simply assumes that the pool size should be increased further because the 150 account limit has been in effect on Peoples Gas and North Shore for over 11 years and the Utilities should have learned to handle an increase in pool size over that time period.

The Utilities' proposals to increase the pool size to 200 accounts are reasonable. They reflect a substantial 33% increase in pool size from the limit currently in effect. Mr. Zack testified in rebuttal and in surrebuttal about the billing and other difficulties the Utilities would encounter if the pool size limit were eliminated entirely or increased dramatically beyond the substantial increase that the Utilities themselves proposed. Zack Reb., NS-PGL Ex. TZ-2.0, 35:771-36:797; Zack Sur., NS-PGL Ex. TZ-3.0 REV, 18:393-19:410. Suppliers frequently change the make-up of their pools as they move customers in and out of them. The advocates for further increasing pool size claim that the Utilities' concerns about billing and administrative problems from increasing pool sizes are overblown, but none of those advocates have to actually deal with those problems. The Utilities' proposal to increase the pool size limit from 150 accounts to 200 accounts should be adopted. However, they should not be compelled to increase the pool size limit beyond the capability of their billing and administrative groups to handle.

b. <u>"Super-pooling"</u>

CNE proposes that the Utilities allow suppliers to "super-pool" all of the pools and individual standalone customers that are under common management. CNE Ex. 1.0, 20:444-445. Under its proposal CNE envisions that it would be applicable to several different measures, only some of which were specified in its Direct Testimony. *Id*., at 20:487-21:502. Those measures that it specified were to determine compliance with seasonal inventory requirements, to determine compliance with storage injection and withdrawal restrictions, and to determine a supplier's net position before applying any Rider P Imbalance Account Charge for either Non-Critical or Supply Surplus Days.

The Utilities initially opposed being compelled to accept any form of super-pooling, based on their concerns about being able to implement it without significant billing system programming and without establishing a separate billing entity. Zack Reb., NS-PGL Ex. TZ-2.0, 36:800-39:855. Staff also opposed the imposition of super-pooling on the Utilities. Staff Ex. 24.0, 22:429-431. However, upon further consideration, the Utilities agreed that they could accept a form of superpooling if it were limited to being used solely for the purpose of determining if the supplier meets the two cycling requirements and if individual stand alone (non-pooled) customers were excluded. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 14:308-312. Vanguard has indicated that it could accept the Utilities' counterproposal on this issue, though it would prefer to include stand alone accounts. Vanguard Ex. 3.0, 4:79-81.

The Utilities' counterproposal to implement a limited form of superpooling reflects a reasonable balance between the interests of the Utilities' sales customers and their transportation customers, and it should be accepted as a reasonable resolution of the merits between the competing interests of all parties.

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

CNE proposed that the Utilities permit customers with different selected standby percentages (SSP) to be in the same supplier pool. CNE Ex. 1.0, 15. The Utilities opposed being compelled to accept pools containing customers with different SSPs in the same pool because extensive programming changes would be required to their billing systems to implement this requirement. Zack Reb., NS-PGL Ex. TZ 2.0, 39:862-40:871. However, the Utilities have indicated that they could accept such pools if the requirement were implemented in the following manner: (1) a pool's MDQ would be the summation of the underlying customer (contract) MDQs, and (2) a pool's SSP would be the weighted average of its customers' (contract) SSPs. *Id*., at 874-887. A scenario spelling out the Utilities' understanding of how an acceptable proposal would operate was set forth in Mr. Zack's Rebuttal Testimony, and no party took issue with that scenario. *Id*. CNE concluded that it was reasonable. CNE Ex. 2.0, 29:605-614.

The Utilities' counterproposal permitting customers with different SSPs to be in the same pool should be accepted as a reasonable resolution of the competing interests of all parties.

7. Operational Issues

a. Intra Day Allocations and Intra Day Nominations

The Utilities originally proposed that each day a customer or supplier with more than one contract or pool be permitted, on an intra-day basis, to re-allocate deliveries between or among its contracts or pools. Zack Dir., NS Ex. TZ-1.0, 47:1072-1084; PGL Ex. TZ-1.0 2REV, 50:1125-1137. The purpose behind the Utilities' proposals was to permit suppliers to reallocate gas among their contracts to permit them to offset any potential gas deficiencies and avoid penalties. *Id*.

CNE supported the Utilities' proposals for intra-day allocations, but it also proposed that they be compelled to allow transportation customers to make intra-day nominations. CNE-Gas Ex. 1.0, 8:162-163. CNE claims that intra-day nominations are standard in the industry. *Id*.

The Utilities do not accept CNE's proposal. Zack Reb., NS-PGL Ex. TZ-2.0, 41:898-909. Intra-day nominations are industry standard as far as interstate pipelines are concerned, but they certainly are not industry standard as far as local gas distribution companies are concerned, particularly as far as major Illinois gas distribution companies are concerned. *Id*., at 910-914; Zack, Tr. At 781:8-10. The Utilities have responsibilities greater than those of marketers like CNE. The Utilities must manage the entire utility system; they are the supplier of last resort and must meet demand with supply, despite a dynamic demand profile, on a real time basis. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 19-20:412-438. The imposition of an obligation on the Utilities to accept intraday nominations from transporters would be a serious problem because the Utilities must scramble to match supply with consumption, and then have to adjust their supply to do so. They can't be in the position of, e.g., trying to shed supply during a warm winter day while marketers are trying to increase their supply because prices are low because it is a warm winter day. The situation is similar to an airplane flight. There are many potential flight paths between two cities and flight plan deviations can be made to account for weather, but when the airplane is on final approach there really is only one path to a safe landing. Similarly, the Utilities can handle a supplier's day-ahead regularly scheduled gas nominations, but last-minute changes to gas nominations can be problematic. The Utilities should not be compelled to accept intra-day nominations from marketers, when doing so could cause the Utilities to be unable to meet demand with supply or to incur penalties to do so.

Finally, in judging tariffs, one needs to review the rules of the utility as a whole, because each tariff has numerous provisions, and some provisions may be favorable in one area and other provisions may be less favorable. An example is contained in CNE-Gas' own testimony, in which are listed a number of utilities that purportedly allow intraday nominations. CNE-Gas Ex. 1.0, 12:240-253. However, when the actual tariff of one of these utilities was examined, it was revealed that the utility requires suppliers to exactly match deliveries and consumption on a daily basis, making intraday nominations more appropriate. CNE-Gas Witness Rozumialski, Tr. At 781:2-7. Furthermore, on cross examination, CNE-Gas witness Mr. Oroni admitted that in his direct testimony in Nicor Gas' recent rate case (No. 04-0779), in which the Commission declined to compel Nicor Gas to offer intraday nominations, he mistakenly testified that Peoples Gas offered intraday nominations in support of his argument that Nicor Gas should be compelled to do so. Orani, Tr. At 776:10-22 and 777:1-21.

The Utilities should not be compelled to permit intraday nominations by gas transporters, but the Utilities' proposals to allow intraday allocations are reasonable and should be accepted by the Commission.

b. Delivery Restrictions

CNE and Multiut witnesses expressed concerns in their Rebuttal Testimony about delivery restrictions. CNE Ex. 2.0, 24-27; Multiut Ex. 2.0, 5. The Utilities impose delivery restrictions only when customer deliveries are disproportionate to customer consumption requirements. Zack Reb., NS-PGL Ex. TZ-2.0, 43:943-948; Zack Sur., NS-PGL Ex. TZ-3.0 REV, 20:441-448. CNE suggested that delivery restrictions tied to the prior day's usage would be preferable. CNE-Gas Ex. 2.0, 26:548-555. This is impractical, because nominations must be made the day prior to flowing gas, before the current day's actual consumption is known. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 20:441-443. The consumption of FST customers is not metered daily and Rider SST customers who are daily metered have a natural one-day lag before usage is even available. *Id.*, at 20:443-448. The Utilities expected that their proposals to shape transportation customers' AB use to something closer to what applies to the Utilities, along with the discontinuance of Rider FST, would alleviate (but not eliminate) the need to impose delivery restrictions. Zack Reb., NS-PGL Ex. TZ-2.0, 43:949-954. The Utilities hope that their revised proposals concerning Riders FST and SST will mitigate the need to impose delivery restrictions. Zack Sur., NS-PGL Ex. TZ-3.0 REV,9:196-198.

8. Other Large Volume Transportation Issues

a. Accounting for Trading and Storage Activity

Vanguard claims that Peoples Gas and North Shore each improperly handles accounting for imbalance traded gas and storage transfer gas by its transportation customers. Vanguard Ex. 1.0, 6:113-9:194; Vanguard Ex. 2.0, 6:112-9:193. The gist of the complaint seems to be that the Utilities reduce gas in storage in a customer's account by the gas traded away by that customer, but that there is an eight day delay in the Utilities' recording of an increase in gas storage in a customer's account by the amount of gas traded into that customer's account. No other Peoples Gas or North Shore customer or supplier has claimed that the Utilities improperly handles accounting for imbalance traded gas and storage transfer gas by its transportation customers. Peoples Gas and North Shore each maintains that its accounting for its customer trading and storage activity is appropriate in light of some practical administrative issues (Zack Reb., NS-PGL Ex. TZ-2.0, 44:961-45:989), and that neither Vanguard nor any of Peoples Gas' or North Shore's other transportation customers or suppliers are harmed by its accounting methodology. *Id*. Peoples Gas and North Shore also note that Vanguard admitted, both in response to the Utilities' Data Request Nos. 2.06 and 2.07 and in Vanguard's own rebuttal testimony (Vanguard Ex. 3.0, 6:119-121, for each of Peoples Gas and North Shore), that no one has been harmed by the Utilities' accounting for imbalance traded gas and storage transfer gas.

In the absence of evidence of any harm to any of Peoples Gas' or North Shore's customers, and in light of the fact that no other customer has complained of Peoples Gas' or North Shore's accounting for imbalance traded gas and storage transfer gas, the Commission should not order any change in Peoples Gas' or North Shore's accounting for imbalance traded gas and storage transfer gas.

b. Excess Bank and Critical Surplus Day <u>Unauthorized Overrun Charges</u>

Both North Shore and Peoples Gas propose that they continue to be authorized to charge their existing Excess Bank Charge of $0.10 per therm and their Critical Surplus Day Unauthorized Overrun Charge of $6.00 per therm under Riders SST and P. Zack Dir., NS Ex. TZ-1.6, 1; PGL Ex. TZ-1.6, 1. Multiut opposes these charges. Multiut Ex. 1.0, 8. Neither of these charges is new. The Excess Bank Charge is imposed only to deter customers from delivering gas to the Utilities in quantities in excess of the customer's total AB capacity. Tr. At

546:6-17. Absent the Excess Bank Charge, and subject only to the Utilities' end of season storage cycling requirements, a customer would be able to have inventory substantially in excess of its AB without incurring any financial penalty for doing so. The Critical Surplus Day Unauthorized Overrun Charge is assessed only to keep transportation customer supply equal to consumption on days in which there is a critical excess of supply coming into the Utilities' systems. The Utilities should be permitted to continue both of these charges in effect in order to manage their systems.

c. <u>Cash-outs Index</u>

Multiut challenges the Utilities' proposals to sell gas to a customer at 110% of AMIP and to buy gas from a customer at 90% of AMIP to the extent that such customer fails to comply with the Utilities' end of season storage inventory requirements. Tr. At 550:6-8 and 551:10-17. While Multiut calls these proposals "penalties", they are not penal in nature. They are designed to influence customers to comply with the end of season storage inventory requirements, and they can easily be avoided by the customer arranging to fill and deplete its AB in compliance with those requirements at pure market prices. No other party opposed these proposals.

One would expect that suppliers who purport to be in the business of supplying gas to customers should generally be responsible for obtaining and managing their own gas supply and for complying with the Utilities' end of season storage requirements. The Utilities' proposals to (1) sell gas to customers at 110% of AMIP to the extent that the customer fails to comply with the Utilities' November 30 storage injection requirements and (2) buy gas from a customer at 90% of AMIP to the extent that the customer fails to comply with the Utilities' March 31 storage withdrawal requirements are reasonable, and the Commission should permit the Utilities to implement these cash-out proposals.

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

CNE-Gas proposed that the information that the Utilities make available on PEGASys™ include four pieces of data: (1) the customer's Service Classification and Rider(s), (2) the customer's Maximum Daily Quantity (3) the customer's Selected Standby Percentage, and (4) the customer's Allowable Bank. CNE-Gas Ex. 1.0, 24:523-528; CNE-Gas Ex. 2.0, 33:699-715. Vanguard and RGS essentially support CNE-Gas' proposal. Vanguard Ex. 3, 1-3:10-48; RGS Ex. 2.0, 24:29-33. In rebuttal, the Utilities indicated that they would be willing to make these data available on PEGASys™, once they have accepted and processed the customer enrollment request. Zack Reb., NS-PGL Ex. TZ-2.0, 62:1389-1391. In rebuttal CNE-Gas indicated that the Utilities' proposal in rebuttal was a step in the right direction which CNE-Gas supported, though CNE-Gas would prefer the information be made available sooner. CNE-Gas Ex. 2.0, 33:703-715. In surrebuttal, the Utilities indicated that they would be willing to make this information available on PEGASys™ at the time of customer enrollment, subject to Commission approval of the making of this information available. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 33:726-736. That would mean that suppliers would have access to this information at the time of enrollment, but before the customer is "active and flowing" in the supplier pool. *Id*.

D. Small Volume Transportation Program (Choices For You℠ or "CFY")

1. Storage Rights and Aggregation Rights

Retail Gas Suppliers has proposed a significant number of changes to the Utilities' small volume transportation programs. RGS Ex. 1.0, RGS Ex. 2.0. Nicor Advanced Energy ("NAE") supports many of the RGS proposals. NAE Ex. 1.0; NAE Ex. 2.0. The Utilities oppose most, but not all, of these changes. Zack Reb., NS-PGL Ex. TZ-2.0, 47:1040-63:1405; Zack Sur., NS-PGL Ex. TZ-3.0 REV, 25:554-36:798. Each proposal is discussed individually below.

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

RGS claims that the Utilities do not provide CFY suppliers with a significant amount of the daily and monthly injection and withdrawal rights associated with the storage costs that the Utilities recover from CFY customers. RGS Ex. 1.0, 11:12-14. RGS proposes that the Utilities be compelled to assign to CFY suppliers substantially larger specific daily, monthly, seasonal and annual allocations of storage rights. *Id*., at 15-21.

The Utilities oppose RGS's proposal for a number of reasons. First, the gas consumption of CFY customers is not metered daily, so there is no way to verify that CFY supplier injections and withdrawals are within the daily parameters that RGS proposes to establish. Second, RGS's proposal uses peak day (maximum) capabilities, even though these maximum capabilities do not exist with respect to the Utilities' storage assets and rights. Third, RGS's proposal was based on data from 2006, a single, unusually warm year. Finally, while the RGS proposal refers to monthly injection and withdrawal rights, the proposal itself does not quantify those monthly rights in any way. Zack Reb., NS-PGL Ex. TZ-2.0, 48:1060-1069. CFY suppliers already have the ability to inject gas into storage in the summer and withdraw it in the winter. The Utilities also provide balancing services for CFY suppliers and their customers. The 10% daily and proposed 5% monthly delivery tolerances are evidence of the existence of generous storage and balancing rights for the benefit of CFY customers. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 26:562-580.

This is not the first time that the Commission has dealt with the issue raised by RGS. As pointed out by RGS, the Commission dealt with this issue on the Peoples Gas system in ICC Docket No. 01-0470. RGS Ex. 1.0, 18:15-25 and 19:1-17. The Commission also dealt with this issue on the North Shore system in ICC Docket No. 01-0469. As a result of those two proceedings, Peoples Gas and North Shore conducted workshops to provide CFY suppliers with greater flexibility over the use of allocated storage capacity. Based on those workshops, Peoples Gas filed tariff changes that were approved by the Commission. *Id*., at 19:9-10. North Shore also filed similar tariff changes that were approved by the Commission. These tariff provisions gave CFY suppliers monthly storage capacity levels and storage withdrawal rights, based on certain parameters. *Id*., at 19:9-17. When considering the Utilities' proposals here to increase the month-end delivery tolerance by 150%, the Utilities' proposals here are, in the aggregate, more generous to CFY suppliers than those previously approved by the Commission as a result of the workshop process. RGS complains of the Utilities' proposals because they do not reflect abject surrender to RGS' proposals. However, the Utilities' proposals reflect a reasonable allocation of storage rights to CFY suppliers at reasonable charges while maintaining sufficient operational control in the Utilities so that they can accommodate the needs of all of their customers. RGS' proposal would permit a CFY supplier to withdraw up to 66% of its storage inventory as of the close of November 30. Crist, Tr. At 1021:7-12. If a CFY supplier did so and December was colder than normal, a strong possibility would exist that that supplier would not be able to supply its customers' gas requirements. Where would the gas to supply these requirements come from? Presumably, it would have to come from the Utilities. The Utilities could not operate their storage assets in such an irresponsible fashion. CFY suppliers should not be permitted to do so, either.

RGS has proposed that the Utilities adopt a revised Rider AGG. RGS Ex. 2.0, 8:16-23; RGS Ex. 2.1. The Utilities oppose being compelled to adopt RGS' proposed Rider AGG. RGS claims that its proposal is based on tariff provisions currently in effect on the Nicor Gas system. RGS Ex. 2.0, 8:18-20. However, the "Storage Quantity Target Levels" for the winter months provide substantially wider ranges than those in the Nicor Gas rider. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 27:585-587. Below is a comparison of the Storage Quantity Target Levels of the preceding November inventory provided for in the Nicor Gas rider (taken from RGS Ex. 1.2, 8th Revised Sheet No. 75.6) to the end of month Storage Quantity Target Levels, prepared by RGS in its proposed Rider AGG (taken from RGS Ex. 2.1, Original Sheet No. 88), for the four most critical winter months:

	Nicor Gas	**RGS Proposal**
November	55% - 100%	50% - 100%
December	55% - 75%	35% - 100%
January	35% - 60%	15% - 75%
February	15% - 35%	0 – 50%

Similarly, RGS' proposed Rider AGG provides that, to the extent a CFY supplier's aggregation group load increases throughout the winter, storage in place for such customers shall transfer with the customers, and supplier's November 1 Storage Inventory Level will be modified to reflect such changes. RGS Ex. 2.1, Original Sheet No. 86. Conspicuous by its absence is a corresponding provision in RGS Ex. 2.1 to decrease a supplier's November 1 Storage Inventory Level if the supplier's aggregation load decreases. This just highlights some of the ways in which RGS' proposed Ex. 2.1 would operate to the unilateral benefit of CFY suppliers. The Commission should reject RGS' proposal to specifically allocate storage capacity to CFY suppliers.[29]

[29] One of the arguments that RGS makes in support of its proposal to specifically allocate storage capacity to CFY suppliers is that CFY supplier storage needs can be met entirely from Manlove Field. RGS Ex. 2.0, 9:6-7. Similarly, IIEC, CNE-Gas and Vanguard argue that Manlove Field could be used to support their proposed USB. IIEC/CNE/VES Jt. Ex. 2, 9:176-183. The fact that both large and small volume transportation customers want Manlove Field to support services targeted solely for themselves should cause the Commission to reject both efforts.

b. Aggregation Balancing Gas Charge (ABGC)

In response to requests by RGS members and others, the Utilities have proposed to move the billing of the Aggregation Balancing Gas Charge ("ABGC") from the supplier to the customer at the account level. Zack Dir., NS Ex. TZ-1.0, 30:690-698; Zack Dir., PGL Ex. TZ-1.0 2REV, 31:717-32:725. Now that the Utilities have responded to this request, RGS wants even more – the entire removal of the ABGC. RGS Ex. 1.0, 23:19-21.

The Commission should reject RGS' demand to eliminate the ABGC. The Utilities incur costs to provide the storage and daily balancing services that they provide to CFY customers. Zack Reb., NS-PGL Ex. TZ-2.0, 47:1050-1059. Those costs are currently based on the firm storage and related transportation services that the Utilities purchase from ANR Pipeline Company and Natural Gas Pipeline Company of America. It is appropriate for the Utilities to recover these costs from the customers who obtain the benefits of the services provided by the Utilities as a result of the costs incurred by the Utilities. The Utilities could provide neither balancing services nor storage accounts for CFY suppliers unless these costs are incurred. There is no reason any customer class should get free balancing and storage service from the Utilities.

c. Pipeline Capacity Assignment

As an alternative to the specific allocation of storage rights to CFY suppliers, RGS has proposed that the Utilities be compelled to grant CFY suppliers the option to receive an assignment of storage capacity on a one-year recallable basis and pipeline capacity on a month-to-month recallable basis. RGS Ex. 1.0, 22:20-22. The Utilities oppose this alternate proposal because it is not feasible. Zack Reb., NS-PGL Ex. TZ-2.0, 52:1176-53:1188; Zack Sur., NS-PGL Ex. TZ-3.0 REV, 28:615-628. The Utilities cite the administratively active nature of the capacity release process, which must be completed in a short period of time. *Id*. Also, their exercise of recall rights would be cumbersome. RGS disputes the Utilities' assertions in this regard and cites three gas distributors who do conduct capacity release programs. RGS Ex. 2.0, 9:16-20. However, none of the three gas distributors cited by RGS operate in Illinois. The Commission should reject RGS' proposal regarding pipeline capacity assignment.

d. <u>Customer Migration</u>

RGS claims that the Utilities do not adequately adjust a supplier's access to storage when a customer switches suppliers for either another supplier or to or from Utility sales service. RGS Ex. 1.0, 20. The Utilities reject RGS' claim. The Utilities adjust supplier storage rights during the injection season as pool enrollment changes. In addition, the Utilities are proposing a "storage true-up" mechanism that further adjusts storage during the injection season. Zack Reb., NS-PGL Ex. TZ 2.0, 50:1119-51:1136. They do not adjust supplier storage rights for customer migration during the withdrawal season because of the need for the CFY programs to schedule withdrawals in a measured way over the course of winter, with appropriate adjustments for weather. *Id*. Note that this benefits a supplier that loses customers during the withdrawal season. Also, winter period customer migration is reflected in the following winter period's storage allocation to the supplier.

The Utilities' existing practices regarding customer migration are reasonable, and the Commission should not compel the Utilities to change them. The Utilities' proposed storage true-up is reasonable, and the Commission should approve it.

e. <u>Month End Delivery Tolerance</u>

The Utilities have proposed to increase the month-end delivery tolerance for CFY suppliers from 2% of Monthly Adjusted Deliveries to 5% of Monthly Adjusted Deliveries. Zack Dir., NS Ex. TZ-1.0, 28:634-636; PGL Ex. TZ-1.0 2REV, 29:661-663. In response RGS has proposed that the month-end delivery tolerance should be eliminated (RGS Ex. 1.0, 24:20-21), so that there would be no requirement that a CFY supplier's Required Monthly Delivery Quantity be met by that supplier. In rebuttal RGS indicated that it was willing to accept a 10% month-end delivery tolerance as a compromise. RGS Ex. 2.0, 14:7-9. Staff opposed RGS' proposal and would accept the Utilities' proposal on this issue. ICC Staff Ex. 24.0, 17:341-18:345.

It is reasonable that CFY suppliers be required to operate within monthly, as well as daily, delivery parameters, because the Utilities have to operate their systems within similar parameters. The Utilities' proposals to increase the month-end delivery tolerance from 2% to 5%, a 150% increase in tolerance are reasonable. The Utilities' proposals on this issue should be accepted by the Commission.

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

RGS claims that working capital costs related to system gas costs are improperly charged to CFY customers. RGS Ex. 1.0, 34-35. RGS proposes that working capital costs should be included in the Utilities' system gas costs. The Utilities recognize the validity of this claim, and they propose to include a credit from working capital in the CFY customer Aggregation Charge, as is currently the case. Zack Reb., NS-PGL Ex. TZ-2.0, 51:1137-52:1145; Zack Sur., NS-PGL Ex. TZ-3.0 REV, 31:673-684; NS-PGL Ex. TZ-3.4.

The Utilities' proposal on this issue should be accepted as a reasonable resolution of the merits between the competing interests of RGS and the Utilities.

RGS has proposed that the Utilities' administrative Monthly Aggregation Charge be eliminated. RGS Ex. 1.0, 36:8. The basis for RGS' claim is that it believes that all administrative charges should be part of base rates. The Utilities disagree with RGS' claim. Zack Reb., NS-PGL Ex. TZ-2.0, 52:1148-1152. The Utilities need to recover costs associated with CFY program administration, supplier and customer care, and customer education, as well as maintaining and enhancing the systems used to administer the CFY program, including PEGASys™ enhancements.

The imposition by the Utilities of the Monthly Aggregation Charge, supported by the data submitted by the Utilities in NS Ex. TZ-1.7 and PGL Ex. TZ-1.7, continues to be appropriate.

2. Customer Enrollment

a. Customer data issues

i. Customer List Names and Addresses

RGS wants the Utilities to provide customer lists with names and addresses of Service Classification No. 1 customers to CFY suppliers at no cost to those suppliers. RGS Ex. 1.0, 25-28. RGS also wants the customer list to show whether the customer is a Service Classification No. 1N or 1H customer. RGS Ex. 2.0, 15:8-12. The Utilities are willing to provide this information, excluding customers on the Utilities' "do not call" lists, on such terms as the Commission may prescribe without prior customer consent. Zack Reb., NS-PGL Ex. TZ-2.0, 55:1212-1221. However, the Utilities should not be obligated to provide such a list more often than once every six months. *Id*. RGS is willing to accept this limitation. RGS Ex. 2.0, 15:16-18. However, Staff does not want the Utilities to provide any such list absent explicit customer approval. ICC Staff Ex. 24.0, 19:366-368. In light of the disagreement on this issue between the Utilities and RGS on the one hand, and Staff on the other, the Utilities request a specific determination as to whether the Utilities can furnish customer list names and addresses to CFY suppliers without explicit customer approval.

ii. Customer Payment History

RGS claims that the Utilities should be compelled to provide customer payment history to CFY suppliers on request. RGS Ex. 1.0, 38-40. The Utilities are concerned about supplying customer payment history because of its sensitive nature. Zack Reb., NS-PGL Ex. TZ-2.0, 55:1230-57:1270. They proposed that they provide these data only if (1) the Commission authorizes them to do so, (2) the CFY suppliers requesting these data represent and warrant that they have the requisite authorization from the customer to obtain it, and (3) the CFY suppliers indemnify the Utilities and hold them harmless from any customer damage claim if the CFY supplier receiving the data does not have the requisite customer authorization, or if the customer revokes the authority. *Id*. NAE, while expressing support for RGS' position on this issue "in many ways", proposed a variation of the Utilities' proposals on this issue. NAE Ex. 2.0, 11-12:208-241. Staff separately expressed significant concerns about the Utilities supplying customer payment history and customer past due payment data to CFY suppliers. Staff Ex. 24.0, 19:366-383.

The differing positions taken on this issue by the Utilities, Staff, RGS and NAE demonstrate the difficulty of reaching a result that is fair to all interested parties. As a result, the Commission's guidance on this issue is essential. The Utilities have struggled with this issue, and after receiving the positions of all of the parties weighing in on this issue, believe that the following would represent a reasonable resolution. First, before the Utilities would be obligated to provide any such history or data to the CFY supplier, the Utilities should be able to review the form contract(s) of a CFY supplier claiming that the contract(s) authorize it to obtain customer payment history and customer past due payment data. Second, the Utilities should not be responsible if there is any dispute between a CFY supplier and its customer about the scope or effectiveness of a customer's authorization of the Utilities to provide payment history or past due payment data to a CFY supplier. Third, it is appropriate that the CFY supplier indemnify the Utilities against any customer damage claim if the CFY supplier receiving the data does not have the requisite authorization, or if the customer revokes the authority. Consequently, the Utilities continue to believe that the tariff language they proposed to reflect in a new subsection insertion D of Rider CFY, and in a new provision, subsection 5, added to the description of the contract in section F of Rider AGG, are appropriate.

Staff recognizes that the Utilities are uncomfortable in being the gatekeeper for customer payment information, and it also expresses a legitimate concern about such customer information not being sold or used for any purpose other than in connection with gas service. This suggests a need for the Commission to explicitly prohibit CFY suppliers from selling or otherwise using customer information for any purpose other than in connection with gas service regardless of the terms contained in the CFY supplier's boilerplate contract. This also suggests that the mechanism suggested by Staff witness Dr. Rearden, whereby an independent third party verifies a customer's sign up with a CFY supplier, and verifies that customer's agreement to permit the Utilities to provide customer payment history and customer past due payment data, to a CFY supplier, with the costs of the third party verification process to be borne by CFY suppliers, might be the best method to rationalize all the competing interests here. Tr. At 686-693.

iii. <u>Customer Past Due Payment Data</u>

Please see discussion under Section X(B)(3)(a)(ii) of this Initial Brief, *supra*.

iv. <u>Tier 1 and Tier 2 Data</u>

The Utilities have proposed to provide more detailed customer information to CFY suppliers than customer list names and addresses (but not including the customer payment history and customer past due payment data covered under (ii) and (iii) immediately above) in two tiers. Zack Dir., NS Ex. TZ-1.0, 26:587-27:612; PGL Ex. TZ-1.0 2REV, 27:614-28:639. These more detailed data would be provided pursuant to a written contract between the applicable Utility and the CFY supplier. The first tier would not include any customer-specific information and would not require customer consent. It would include therms billed, billing dates and whether the information is based on actual or estimated meter readings. *Id*. The second tier would be customer-specific information and would require customer consent, which would be evidenced by the supplier having one or two customer-specific pieces of information to input as keys to access the information. Second tier information would include name, account number, billing address, premises address, usage, type of meter reading and meter reading dates. *Id*. RGS wants all Tier 1 and Tier 2 data to be provided to all certified alternative retail gas suppliers at no cost to them (RGS Ex. 2.0, 15:19-21 and 16:1-3), simply because it would be useful to them.

The Utilities' proposals regarding the supplying of Tier 1 and Tier 2 customer data to CFY suppliers are reasonable, and the Commission should permit the Utilities to implement them. The Utilities should not be compelled to supply customer data at no cost. This data is essentially market data, and there is no valid reason why alternative retail gas suppliers should receive it on a cost-free basis with no corresponding obligations on the supplier regarding the appropriate use of the data.

b. <u>Evidence of Customer Consent</u>

Please see discussion under Section X(D)(2) of this Initial Brief, *supra*.

c. <u>Minimum Stay Requirement</u>

The Utilities initially proposed to continue to require a CFY customer returning to utility sales service and not selecting another CFY supplier within 60 days of its return to utility sales service to remain on Utility sales service for a minimum of one year before being again eligible to switch to CFY service. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 57:1271-1283. Subsequently, the Utilities modified their proposal to require a customer returning to Utility sales service and not selecting another CFY supplier within 90 days of its return to Utility sales service to remain on Utility sales service for a minimum of one year. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 33:720-725. RGS opposes any form of this minimum stay requirement, claiming that it is an anticompetitive practice. RGS Ex. 1.0, 41:1-23. The Utilities have three reasons for this requirement. Zack Reb., NS-PGL Ex. TZ-2.0, 57:1271-1283. First, it provides reasonable certainty to their gas supply planning. Second, it prevents customers from switching back and forth between CFY suppliers and the Utilities to take advantage of temporary price fluctuations. Third, it is not substantively different from the minimum terms provisions that CFY suppliers insert in their contracts.

The one year minimum stay provision reflected in the Utilities' revised proposal on this issue is neither unreasonable nor anticompetitive. The Utilities should be allowed to continue to enforce this provision, as revised by them.

3. Rider SBO

a. Billing Credit

NAE proposed that the Utilities provide CFY suppliers that single bill under Rider SBO a credit for single billing, to reflect costs avoided by the Utilities by not having to issue a bill for their distribution charges. NAE Ex. 1.0, 7-12:100-224. The Utilities initially rejected providing any credit. Zack Reb., NS-PGL Ex. TZ-2.0, 59:1306-1310. In rebuttal NAE claimed that size of the credit sought should be at least 33 cents per customer per month. NAE Ex. 2.0, 4-6. In surrebuttal the Utilities agreed to provide a 33 cent per customer (per month) credit for CFY suppliers billing under Rider SBO. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 31:686-692. The proposed credit offered by the Utilities reflects their estimate of postage and paper costs. Tr. At 624:9-17. Therefore, this issue should be resolved by accepting the billing credit offered by the Utilities.

b. **Order of Payments**

The order of payments that applies when a customer makes a partial bill payment historically has differed between the application of payment proceeds billed under Rider SBO and that applied to payment proceeds billed under the Utilities' single bill. In either case, a single bill is issued for both CFY supplier gas charges and LDC gas distribution charges; the only difference is that in one case the Utility issues the single bill and in the other case the CFY supplier issues it. NAE initially proposed that the order of payments for Rider SBO should be identical to the order of payments for CFY suppliers that bill on the Utilities' single bill. NAE Ex. 1.0, 17:326-328. Under the Rider SBO order of payments the Utilities get all their charges paid before the CFY supplier receives any payment. On the other hand, under the LDC single billing option the order of payment is Utility past due charges, then CFY supplier past due charges, then Utility current charges, then CFY supplier current charges.

In response to NAE's proposal, the Utilities proposed that the Rider SBO order of payments be adopted for the LDC single billing option. Zack Reb., NS-PGL Ex. TZ-2.0, 60:1328-1330. Both NAE and RGS objected to the Utilities' proposal on this issue. NAE Ex. 2.0, 7-9; RGS Ex. 2.0, 19:12-14. The Utilities' proposal on this issue addresses the substance of NAE's original complaint as reflected in its Direct Testimony. The Rider SBO order of payments resulted from the Commission's orders in Docket Nos. 01-0469 and 01-0470, while the Commission has never addressed the order of payments under the LDC billing option. Zack Reb., NS-PGL Ex. TZ 2.0, 59:1318-1325. Therefore, the Utilities' proposal on this issue is reasonable and should be accepted by the Commission.

c. **NSF Checks**

NAE also is unhappy with the Utilities' existing practice regarding the return of customer non-sufficient funds (NSF) checks. NAE Ex. 1.0, 17-20. When one of the Utilities issues a single bill and receives a customer check, the Utility credits the appropriate funds to the CFY supplier, and if the check later is determined to be NSF, the Utilities do not try to recover the uncollected funds from the CFY supplier. *Id*. Correspondingly, if a CFY supplier billing under Rider SBO were to receive a check, the supplier would pay the appropriate funds to the relevant Utility, and if the check later was determined to be NSF, then the Utility would not return any portion of the funds to the CFY supplier that accepted the NSF check for payment. *Id*. NAE sees this as a scheme favoring LDC single billing and discouraging the use of SBO. *Id*., at 19:378-398. NAE wants the Utilities to reimburse the CFY suppliers for any proceeds paid by the CFY suppliers to the Utilities that relate to customer NSF checks.

The Utilities strongly disagree with NAE on this issue. The party issuing the single bill – whether it is the utility under the LDC billing option or the CFY supplier under Rider SBO – should bear the risk associated with a customer NSF check. Zack Reb., NS-PGL Ex. TZ-2.0, 60:1334-1336; Zack Sur., NS-PGL Ex. TZ-3.0 REV, 32:706-714. If the Utilities were to accept NAE's proposal on this issue, the Utilities always would assume all risk under both options and suppliers, whether billing themselves under SBO or through the Utilities, and the CFY suppliers would have no risk. Consequently, the Commission should accept the Utilities' proposal to continue the existing practice regarding the treatment of customer NSF checks.

4. <u>**Purchase of CFY Supplier Receivables**</u>

The Commission should not adopt RGS' proposal to compel the Utilities to purchase the receivables of CFY suppliers. *See* Crist Dir., RGS Ex. 1.0, 31:2 – 34:20; Crist Reb., RGS Ex. 2.0, 16:19 - 21:7. RGS' proposal is unwarranted and inappropriate, for several reasons.

First, Peoples Gas and North Shore are not in the business of offering purchase of receivables service to third parties, they do not wish to offer this service, and their information systems and business processes are not set up to provide this service. Borgard Reb., NS-PGL Ex. LTB-2.0, 15:317-320. RGS' unsupported assertions that the Utilities have or might have such information systems and business processes are incorrect. Borgard Sur., NS-PGL Ex. LTB-3.0, 9:178-191. Within the boundaries of governing law, a utility has discretion to manage the conduct of its business. *E.g.*, *Lowden v. Illinois Commerce Commission*, 376 Ill. 225, 231 (1941). No valid grounds have been presented to support the Commission's ordering the Utilities to go into this non-utility line of business.

Second, RGS' proposal is an inappropriate attempt to shift business risks from CFY suppliers to the Utilities and utility customers. Borgard Reb., NS-PGL Ex. LTB-2.0, 15:320-326. RGS attempts to argue otherwise, but RGS cannot alter the fact that the Utilities do not now have the risks associated with collecting the receivables in question. Borgard Sur., NS-PGL Ex. LTB-3.0, 9:192 – 10:203. Indeed, the answers of RGS' witness at the evidentiary hearing to questions of the Administrative Law Judges show that, while the CFY suppliers perform credit checks now, they would stop doing so if RGS' proposal were adopted, which would mean that the risk shifted to the Utilities would be much greater than the CFY suppliers' risks now. *See* Crist, Tr. 1023:7 – 1025:10.

Third, RGS' proposal inappropriately and incorrectly contemplates that the Utilities should and would be able to invoke, and carry out, the threat of disconnection of their customers, even when those customers are current on their obligations to the Utilities. Borgard Reb., NS-PGL Ex. LTB-2.0, 15:326-330; Borgard Sur., NS-PGL Ex. LTB-3.0, 10:204-219. RGS' proposal not only inappropriately interferes with and harms the relationship between the Utilities and their customers, *id.*, but it is inconsistent with the Commission's rules regarding disconnection, which do not provide for disconnection when a customer owes a debt to an alternate supplier, 83 Ill. Adm. Code § 280.130(a). In contrast, CFY suppliers have many mechanisms to avoid and reduce these risks that are not generally available to the Utilities. Borgard Sur., NS-PGL Ex. LTB-3.0, 10:220 – 11:233.

Fourth, RGS' vague proposal, at least as presented in testimony, provides for no discount, no other compensation, and no means for the Utilities to recover the added risks, costs, and expenses that would be taken on by the Utilities. Borgard Reb., NS-PGL Ex. LTB-2.0, 15:334 – 16:342; Borgard Sur., NS-PGL Ex. LTB-3.0, 12:256-268; *see also* Crist Dir., RGS Ex. 1.0, 31:2 – 34:20; Crist Reb., RGS Ex. 2.0, 16:19 – 21:7. At the evidentiary hearing, RGS' witness airily offered up the theory that no discount is appropriate because this is a base rate case and there can be an increase in the Utilities' uncollectibles expenses recovered through their tariffs. S*ee* Crist Tr., 1026:12-18. However, there is no data in the record that would come close to providing a basis for calculating how much the Utilities' revenue requirements would need to be increased to offset the shift of risks, burdens, and expenses, especially when, as noted above, the CFY suppliers would abandon credit checks, which would increase the risks, burdens, and expenses.

Finally, RGS' argument that Senate Bill 1299, which applies only to electric utilities, supports RGS' proposal, is not reasonable, because the General Assembly chose not to extend the requirement of a purchase of receivables program to gas utilities. Borgard Sur., NS-PGL Ex. LTB-3.0, 13:269-276. Moreover, Senate Bill 1299, which requires electric utilities with more than 100,000 customers to adopt a purchase of receivables program, is not consistent with RGS' proposal. For example, the legislation provides for "a just and reasonable discount rate to be reviewed and approved by the Commission after notice and hearing. The discount rate shall be based on the electric utility's historical bad debt and any reasonable start-up costs and administrative costs associated with the electric utility's purchase of receivables." There are no facts in the evidentiary record upon which the Commission could determine an appropriate discount rate. RGS' proposal should be rejected.

5. **PEGASys™ and Customer Information**

There is general agreement among the parties that the Utilities' electronic bulletin board system, PEGASys™, should be improved. The Utilities have proposed substantial improvements to it, and want to be able to implement them in an orderly, efficient manner. Some of the suppliers want the Commission to order that the planned improvements be implemented within 30 days of the issuance of a final order in these proceedings. RGS Ex. 1.0, 40:5-21; RGS Ex. 2.0, 25:1-23 and 26:1-3; NAE Ex. 1.0, 21:412-22:444; NAE Ex. 2.0, 10:171-11:194.

The Utilities have not stood still in connection with PEGASys™. They made improvements in it from time to time in the past, and they plan substantial additional improvements. Earlier this year, they eliminated the meter number requirement for enrollment purposes and to retrieve 24-month usage histories. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 36:795-798. They have proposed to eliminate the monthly charges and per minute of usage fees that usually are in effect for a customer's use of PEGASys™. Zack Dir., NS Ex. TZ-1.0, 45:1036-46:1043; PGL Ex. TZ-1.0 2REV, 48:1089-1096. They also plan to enhance the mechanism by which CFY suppliers interact with the Utilities to process (1) account enrollments, amendments and terminations; (2) billing charges and adjustments; and (3) LIHEAP grants. Zack Reb., NS-PGL Ex. TZ-2.0, 61:1351-1356. They also plan to provide a means to permit a customer to extract existing and new reporting data, as well as to enhance certain existing PEGASys™ reports. *Id.*, at 1356-1365. However, they should not be compelled to implement these improvements according to an artificially imposed external deadline. They should implement them in an orderly and efficient manner. Zack Reb., NS-PGL Ex. TZ-2.0, 62:1375-1381. Note that the Utilities expect to implement all of the PEGASys™ improvements no later than August, 2008 (*Id*., at 61:1370-1372), and perhaps as early as June 2008. Zack Sur., NS-PGL Ex. TZ-3.0 REV, 36:794-795. If final orders were issued in these proceedings by February 1, 2008, then the PEGASys™ enhancements would have to be implemented by March 1, 2008, if the artificial deadline advocated by RGS and NAE were imposed. Mathematically, it appears that there is, at most, a five month difference between the implementation time proposed by the Utilities and that proposed by RGS and NAE. The Utilities should be accorded the discretion to implement these improvements in a cost effective manner pursuant to their proposed schedule, and the artificial deadline proposed by RGS and NAE should be rejected.

E. Tariff Corrections and Clarifications

The Utilities have proposed six corrections and clarifications to the proposed transportation tariffs, one of which was made moot by the Utilities' proposed changes to Rider SST in their surrebuttal testimony. Zack Reb., NS-PGL Ex. TZ-2.0, 63:1408-65:1453. Each is listed below. The Utilities also proposed a clarification to their Terms and Conditions of Service. No party has objected to any of them, and they all should be accepted by the Commission.

1. Rider SST, Section F

Rider SST, Section F, includes a monthly limitation on withdrawals from the AB, but it is not clear what happens if the monthly limit is exceeded. The implication from Section E, which defines the daily order of deliveries to the customer, is that gas taken in excess of the lesser of one-third or inventory limitation would be purchased under the companion classification up to the SSQ. However, the Utilities propose to make that clear by adding the following sentence to the end of the last paragraph in Section F: "For quantities that would be in excess of this limitation, the customer shall purchase gas under the Companion Classification in a quantity not to exceed the product of the SSQ times the number of days in the month minus standby service gas purchased during the month and any remaining quantity shall be Unauthorized Use."

2. **<u>Rider TB, Section A</u>**

For Peoples Gas, the Rider TB calculation of the Imbalance Coincidence Factor should be limited to data associated with S.C. No. 4 customers. Only S.C. No. 4 customers are eligible for Rider TB, and only their data should be used. Consequently, Peoples Gas proposes to add in Rider TB, Section A, Imbalance Coincidence Factor, a new sentence before the last sentence of the definition: "For purposes of determining the ICF, the Company shall use only Service Classification No. 4 customers' data."

3. **<u>Rider LST-T</u>**

If the Commission approves Peoples Gas' proposal to consolidate S.C. Nos. 3 and 4, then the Daily Demand Measurement Device Charge will not be assessed under Rider LST-T because daily metering is an incident of service under S.C. No. 4. However, the language pertaining to the customer's obligations relating to telephone wiring needs to be maintained. Accordingly, Peoples Gas proposes to delete the charge from Section B of Rider LST-T and add the non-charge language to Section J of Rider LST-T.

4. **<u>Rider SST, Section H</u>**

A proposed change to Rider SST, Section H, was made moot by the Utilities' proposed changes to Rider SST in their surrebuttal testimony.

5. **Rider SST, Section K**

Rider SST, Section K, addresses customers who do not yet have daily metering installed. There is a minimum AB requirement and a gas purchase obligation if the minimum AB is not met. The Utilities proposed that the purchase price be 110% of the greater of the Gas Charge or the Average Monthly Index Price ("AMIP"). For simplicity, the Utilities propose that the price simply be 110% of the AMIP.

6. **Rider TB, Section H and Rider P, Section G**

The imbalance trading provision in Rider TB, Section H, could result in customers trading gas beyond the amount of their imbalance. The function of a trade for these customers should be to reduce or eliminate the imbalance and not to create another imbalance. For example, a customer should not be able to trade negative imbalance gas such that it is in a positive imbalance situation. The Utilities propose that the following be added to the second paragraph of Section H: "or increase the amount of the imbalance." A comparable change in Rider P, Section G, would be appropriate.

7. **Terms and Conditions of Service**[30]

a. **Service Activation Charges**

The Utilities propose to increase the Service Activation Charge, which recovers a portion of the costs related to initiating gas service at a premises. Grace Dir., PGL Ex. VG-1.0 2REV, 29:641-642; NS Ex. VG-1.0 3REV, 25:549-550. There are two types of service activations: a "successor turn-on," and a "straight turn-on." A successor turn-on occurs when the customer moving out calls and discontinues gas service at approximately the same time as the applicant moving in calls and request gas service. In this instance only a meter reading is required. A

[30] This subsection concerns sales customers, not transportation customers. Its inclusion here is an artifact resulting from the negotiation of the joint outline for these briefs.

straight turn-on occurs when there has never been gas at the location, or when the prior customer cancelled service and the gas has actually been turned off before new service is requested. In this instance the gas has to be turned on and the appliances relit. Id.

Both North Shore and Peoples Gas performed a study on these charges. The results are shown in NS Ex. VG-1.9 and PGL Ex. VG-1.10. Both studies show the cost is higher than the respective Company's proposed change in this docket: Harden Staff Ex. 9.0, 7:144-8:152. North Shore proposes charging $18.00 for a successor turn-on, and $28.00 for a straight turn-on including the relighting of four appliances, plus $5.00 for the fifth and each additional appliance to be activated. Grace Dir., NS Ex. VG-1.0 3REV, 26:562-567. Peoples Gas proposes charging $12.00 for a successor turn-on, $20.00 for a straight turn-on, including the relighting of four appliances, plus $5.00 for the fifth and each additional appliance to be activated. Grace Dir., PGL Ex. VG-1.0 2REV, 30:657-659.

Staff witness Ms. Harden has reviewed the supporting documentation and agrees with the changes proposed by North Shore and Peoples Gas. Harden, Staff Ex. 9.0, 8:157. No other parties addressed this matter.

b. <u>Service Connection Charges</u>

A Service Reconnection Charge is a charge assessed to a customer whose gas has previously been turned off for any number of reasons, such as nonpayment of bills or the customer's own request. Grace Dir., PGL Ex. VG-1.0 2REV, 30:670-31:677; NS Ex. VG-1.0 3REV, 27:578-580. Each customer is granted a waiver of one reconnection charge each year, except in the situation where the customer voluntarily disconnects and then requests reconnection within twelve months, or in the situation in which service is disconnected at the main. Grace Dir., PGL Ex. VG-1.0 2REV, 30:672-31:675; NS Ex. VG – 1.0 3REV, 27:580-583.

As with the Service Activation Charge, the Utilities propose to restructure the Service Reconnection Charge to include a basic charge that includes the relighting of up to four appliances, and to assess a charge for the fifth and each additional appliance. The Utilities are proposing a slight increase to the charges for all three types of reconnection: (1) basic reconnections which only require a meter turn-on; (2) reconnections which require the Company to set a meter; and (3) reconnections that involve excavating at the main. Grace Dir., PGL Ex. VG-1.0 2REV, 30:671-31:678; NS Ex. VG-1.0 3REV, 27:579-586.

North Shore proposes charging $50.00 for a basic reconnection, $90.00 if the meter has to be reset, and $275.00 if service has to be reconnected at the main. Grace Dir., NS Ex. VG-1.0 3REV, 27:596-600. Peoples Gas proposes charging $50.00 for a basic reconnection, $100.00 for a reconnection when the meter has to be reset, and $275.00 when service has to be reconnected at the main. Grace Dir., PGL Ex. VG-1.0 2REV, 31:687-695.

The Companies provided the results of a study on these charges in North Shore Gas Ex. VG-1.9 and Peoples Gas Ex. VG-1.10. Both studies show the actual cost is even higher than the charge the Companies are proposing in this docket.

c. <u>Second Pulse Data Capability</u>

Certain meters, meter correctors, and daily demand measurement devices are capable of delivering a "second pulse" signal to specialized devices that can capture and transmit metering data. Second Pulse Data Capability can provide this signal and make real-time usage readings to customers. While the Companies does not require such capability, a few large volume customers have made requests to receive the second pulse output to help manage their gas usage. Grace Dir., PGL Ex. VG-1.0 2REV, 33:725-730, NS Ex. VG-1.0 3REV, 29:633-638. The Utilities proposes a charge of $14.00, set at cost, to customers who elect Second Pulse Data Capability. Grace Dir., PGL Ex. VG-1.0 2REV, 33:737-738; NS Ex. VG-1.0 3REV, 30:645-646.

Staff witness Ms. Harden has reviewed North Shore and Peoples Gas' supporting documentation and agrees to the monthly charge for Second Pulse Data Capability. Harden Dir., Staff Ex. 9.0, 12:245-246. No other Parties have addressed this issue.

North Shore and Peoples Gas also propose to revise the first sentence of the second paragraph of the section entitled "Second Pulse Data Capability" to state "Initial terms of the contract shall end on the first April 30 following the effective date thereof, and the contract shall automatically renew for one-year periods upon expiration of the initial term and each one-year extension." This change does not substantially affect the second pulse proposal. The change was made for consistency since many of the contracts automatically rollover on May 1. Grace Sur., NS-PGL Ex. VG-3.0, 29:615-623.

XI. UNION PROPOSALS

Peoples Gas shares a number of the general views expressed by Local Union No. 18007, Utility Workers Union of America, AFL-CIO ("Local 18007"), but the Commission should not adopt the proposals made by Local 18007. The proposals (which relate only to Peoples Gas) are not warranted and are inappropriate.

When an employee who is a member of Local 18007 leaves Peoples Gas, or is promoted to a management (non-union) position, the utility currently has a decision to make: it can hire or promote another Union employee to fill the spot, or it can decide not to do so, in the utility's discretion. Through its "One For One" proposal, however, Local 18007 initially proposed to take that decision entirely away from Peoples Gas, and require that every vacated union employee position be filled. The revised version of the proposal still inappropriately would circumscribe and invade the role of management.

In ICC Docket No. 06-0540 (Order, February 7, 2007), in which the Commission considered the transaction by which Integrys Energy Group, Inc., became the parent corporation of Peoples Energy Corporation, which in turn was and remains the parent corporation of Peoples Gas and North Shore, the Commission approved three Conditions that were the result of negotiations between Local 18007 and the Utilities. Conditions 31, 32, and 33 directed the Utilities not to engage in reorganization-related layoffs, to negotiate with Local 18007 regarding training and replenishment of union workers, and to undertake a hiring plan to fill some positions. Gennett Dir., UWUA Ex. 1.0, 4:3-14. Local 18007 agrees that the Utilities have complied with these Conditions. *Id*., 5:10 - 6:8.

Local 18007, in the instant consolidated docket, would like to achieve through a Commission order what it has not been able to bring about through negotiation: a rigid "One For One" program at Peoples Gas. In rebuttal testimony, Local 18007 agreed that its One For One proposal could have exceptions for technological or infrastructure changes, but Local 18007 did not provide specifics for the nature of those exceptions. *See* Gennett Reb., UWUA Ex. 2.0, 16:7-11; Gennett, Tr. at 794:14-19. Local 18007 suggested that its exceptions are consistent with the "management rights" provision of the collective bargaining agreement between Peoples Gas and Local 18007, under which Peoples Gas has complete discretion not to promote anyone to fill a vacant position, but, as cross-examination showed, the union's position still very significantly limits (albeit in poorly defined ways) management's role and subjects it to unprecedented review, including by the Commission. *See* Gennett, Tr. at 807:17 - 808:2, 819:12 – 822:22.

There are two primary reasons that the "One For One" proposal should be rejected. First, it is not an appropriate issue for the Commission to regulate. The Commission regulates the Utilities on a wide variety of areas, but labor relations are not among them. In this case, Peoples

Gas has a collective bargaining agreement with Local 18007. The agreement is not approved by the Commission, and problems that arise under that agreement would either be governed by the agreement's own grievance procedure (Gennett, Tr. at 822:8-18), or would fall under the jurisdiction of a federal agency or afederal court. 29 U.S.C. § 160(k) (the NLRB has primary jurisdiction over disputes arising out of allegations of unfair labor practices); *San Diego Bldg. Trades Council v. Garmon*, 359 U.S. 236, 245 (1959). *See also Marquez v. Screen Actors Guild*, 525 U.S. 33, 49 (1998) (labor disputes fall within the primary jurisdiction of the NLRB in part to promote a uniform interpretation of the NLRA). Suits for violation of contracts between an employer and a labor organization representing employees may also be brought in any district court of the United States having jurisdiction over the parties. 29 U.S.C. § 185(a). State agencies and courts do not generally get involved. Yet, under Local 18007's proposal, the Commission would be forced to insert itself into these issues. *See* Gennett, Tr. at 821:12-18.

Second, a straight "One For One" procedure would not give Peoples Gas the flexibility it should have to reduce via attrition the ranks of senior positions if they are not really necessary. The Commission should encourage the companies it regulates to be efficient. Section 1-102 of the Public Utilities Act, 220 ILCS 5/1-102, while it is a finding rather than an operative provision of the Act, indicates that the Commission should encourage efficiency, including the efficient allocation of human resources. While it is not clear exactly how the One For One proposal as modified in rebuttal testimony would affect the Utilities' hiring and promotion practices if the proposal had exceptions for technology and infrastructure changes, it is clear that the Utilities could have less flexibility and more possible disputes, as indicated above. Especially given the Utilities' willingness to agree to and abide by the conditions set forth in the reorganization approval order, to impose the proposal would constitute an unwarranted invasion of the Utilities' management prerogatives. Doerk Reb., NS-PGL Ex. ED-2.0, 5:101 - 6:113; Borgard Reb., NS-PGL Ex. LTB-2.0, 13:294 - 14:308.

Local 18007 also did not justify its related report and audit proposals. *See* Gennett Dir., UWUA Ex. 1.0, 20:8 – 21:6. Before approving such an audit, the Commission would need to find that there are reasonable grounds to believe that the audit requested by Local 18007 is necessary to assure that the utility is providing adequate, efficient, reliable, safe, and least-cost service, or that the audit is likely to be cost-beneficial in enhancing the quality of service or the reasonableness of rates. 220 ILCS 5/8-102. The evidentiary record here does not demonstrate either of those grounds.

XII. CONCLUSION

Accordingly, for the reasons appearing of record and the reasons stated herein, Peoples Gas and North Shore respectfully request that the Commission enter findings and make conclusions on all contested issues consistent with the Utilities' positions taken in testimony and/or stated herein regarding the evidence in the record and the applicable law.

Dated: October 12, 2007

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