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.	:	

EXCEPTIONS TO THE PROPOSED ORDER OF
NORTH SHORE GAS COMPANY AND THE
PEOPLES GAS LIGHT AND COKE COMPANY

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Dated: December 14, 2007

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In accordance with the schedule set forth in the Administrative Law Judges' (the "ALJs") Proposed Order of November 26, 2007 (the "Proposed Order"), and Section 200.830 of the Rules of Practice of the Illinois Commerce Commission (the "Commission" or "ICC"), 83 Ill. Adm. Code § 200.830, North Shore Gas Company ("North Shore") and The Peoples Gas Light and Coke Company ("Peoples Gas") (together, "the Utilities" or "Companies") submit this Exceptions to the Proposed Order (the "NS-PGL Exceptions") containing proposed revised and replacement language in black-lined format and are separately filing a Brief on Exceptions that supports the proposed Exceptions.

EXCEPTIONS

Please note that the Utilities have included only those sections of the consensus common outline adopted by the Administrative Law Judges in these proceedings as to which the Utilities are proposing Exceptions to the Proposed Order.

II. RATE BASE

E. Cash Working Capital [and Appendix A, pages 10-11, and Appendix B, pages 10-11]

Exception No. 1

Page 10 of Appendix A to the Proposed Order, which sets forth the cash working capital calculations for Peoples Gas, should be revised to reflect: (a) the exclusion of depreciation and amortization; (b) the exclusion of capitalized payroll-related expenditures; and (c) the inclusion of pass through taxes in revenues as well as expenses. After the necessary corrections are made, revised Page 10 of Appendix A should be consistent with the table on the following page.

The Peoples Gas Light and Coke Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Thousands)

Line (A)	Item (B)	Amount (C)	Lag (Lead) (D)	CWC Factor (E) (D/365)	CWC Requirement (F) (C*E)	Column C Source (G)
1	Revenues $	1,350,489	49.44	0.13545	$ 182,927	Appendix A page 11
2	Pass Through Taxes	205,491	49.44	0.13545	27,834	Appendix A pages 1 and 13
3	Total Revenues $	1,555,980			$ 201,761	
4	Pensions and Benefits	31,011	(28.50)	(0.07808)	(2,421)	Appendix A page 11
5	Payroll and Withholdings	58,223	(14.23)	(0.03899)	(2,270)	Appendix A page 11
6	Inter Company Billings	48,189	(36.22)	(0.09923)	(4,782)	PGL Ex. MJA-1.1, Company Schedule B-8, Page 1, Column H, Line 3
7	Natural Gas	1,084,326	(42.05)	(0.11521)	(124,920)	ICC Staff Ex. 13.0, Sch. 13.7 P, Column B, Line 2
8	Other Operations and Maintenance	89,657	(49.51)	(0.13564)	(12,161)	Appendix A page 11, Line 16
9	Taxes Other Than Income	224,009	(43.67)	(0.11964)	(26,801)	Appendix A page 13
10		-		0.00000	0	
11	Interest Expense	24,392	(76.99)	(0.21093)	(5,145)	Appendix A page 7
12	Federal Income Tax	60,581	(37.88)	(0.10378)	(6,287)	Appendix A page 1
13	State Income Tax	9,864	(37.88)	(0.10378)	(1,024)	Appendix A page 1
14	TOTAL				$ 24,949	Sum of Lines 1 through 13
15	Cash Working Capital per Order		$ 24,949			Line 14
16	Cash Working Capital per Company		30,896			PGL Ex. SF-2.1P, Line 4
17	Difference -- Adjustment		$5,947			Line 16 minus Line 15

Exception No. 2

Page 11 of Appendix A to the Proposed Order, should be revised to reflect: (a) the inclusion of pass through taxes in revenues; and (b) the accurate amount of Inter Company Billings. After the necessary corrections are made, revised Page 11 of Appendix A should be consistent with the table on the following page.

The Peoples Gas Light and Coke Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Thousands)

Line (A)	Revenues (B)	Amount (C)	Source (D)
1	Total Operating Revenues	$ 453,457	Appendix A page 1, Line 5
2	Pass Through Taxes	205,491	Appendix A pages 1, Line 17 and 13, Line 19
3	PGA Revenue	1,084,326	ICC Staff Ex. 13.0, Sch. 13.7 P, Column B, Line 2
4	Uncollectible Accounts	(39,090)	Appendix A page 1 Line 6
5	Depreciation & Amortization	(59,203)	Appendix A page 1 Line 14
6	Return on Equity	(89,001)	Appendix A page 1 Line 24
7	Total Revenues for CWC calculation	$ 1,555,980	Sum of Lines 1 through 6
8	Total Return on Rate Base	$ -	
9	Percentage Equity	56.00%	ICC Staff Ex. 17.0, Schedule 17.1
10	Return on Equity	$ -	Line 8 times Line 9
11	O & M Expenses	$ 266,170	Appendix A page 1 Line 19 minus Appendix A, page 1, Line 14
12	Pensions and Benefits	(31,011)	PGL Ex. MJA-1.1, Company Schedule B-8, Page 1 of 2, Column H, Line 1
13	Payroll and Withholdings	(58,223)	PGL Ex. MJA-1.1, Company Schedule B-8, Page 1 of 2, Column H, Line 2
14	Uncollectible Accounts	(39,090)	Appendix A page 1 Line 6
15	Inter Company Billings	(48,189)	PGL Ex. MJA-1.1, Company Schedule B-8, Page 1 of 2, Column H, Line 3
16	Other Operations & Maintenance	$ 89,657	Sum of Lines 11 through 15

Exception No. 3

Page 10 of Appendix B to the Proposed Order, which sets forth the cash working capital calculations for North Shore, should be revised to reflect: (a) the exclusion of depreciation; (b) the exclusion of capitalized payroll-related expenditures; and (c) the inclusion of pass through taxes in revenues as well as expenses. After the necessary corrections are made, revised Page 10 of Appendix B should be consistent with the table on the following page.

North Shore Gas Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Thousands)

Line (A)	Item (B)	Amount (C)	Lag (Lead) (D)	CWC Factor (E) (D/365)	CWC Requirement (F) (C*E)	Column C Source (G)
1	Revenues	$ 266,876	41.08	0.11255	$ 30,036	Appendix B page 11
2	Pass Through Taxes	18,991	41.08	0.11255	2,137	Appendix B pages 1 and 13
3	Total Revenues	$ 285,867			$ 32,174	
4	Pensions and Benefits	4,765	(40.92)	(0.11211)	(534)	Appendix B page 11
5	Payroll and Withholdings	5,220	(14.83)	(0.04063)	(212)	Appendix B page 11
6	Inter Company Billings	11,233	(36.78)	(0.10077	(1,132)	NS Ex. MJA-1.1, Company Schedule B-8, Page 1, Column H, Line 3
7	Natural Gas	226,316	(41.84)	(0.11463)	(25,943)	ICC Staff Ex. 13.0, Sch. 13.7 N, Column B, Line 2
8	Other Operations and Maintenance	13,603	(55.35)	(0.15164)	(2,063)	Appendix B page 11 Line 16
9	Taxes Other Than Income	21,026	(40.28)	(0.11036)	(2,320)	Appendix B page 13
10		-		0.00000	0	
11	Interest Expense	4,320	(91.25)	(0.25000)	(1,080)	Appendix B page 7
12	Federal Income Tax	2,232	(37.88)	(0.10378)	(232)	Appendix B page 1
13	State Income Tax	11	(37.88)	(0.10378)	(1)	Appendix B page 1
14	TOTAL				$ (1,343)	Sum of Lines 1 through 13
15	Cash Working Capital per Order		$ (1,343)			Line 14
16	Cash Working Capital per Company		(1,124)			NS Ex. SF-2.1N, Line 4
17	Difference -- Adjustment		$ (219)			Line 15 minus Line 16

Exception No. 4

Page 11 of Appendix B to the Proposed Order, should be revised to reflect: (a) the inclusion of pass through taxes in revenues; and (b) the accurate amount of Inter Company Billings. After the necessary corrections are made, revised Page 11 of Appendix B should be consistent with the table on the following page.

North Shore Gas Company
Adjustment to Cash Working Capital
For the Test Year Ending September 30, 2006
(In Thousands)

Line (A)		Revenues (B)	Amount (C)		Source (D)
1	Total Operating Revenues		$	62,646	Appendix B page 1, Line 5
2	Pass Through Taxes			18,991	Appendix B pages 1, Line 17 and 13, Line 14
3	PGA Revenue			226,316	ICC Staff Ex. 13.0, Sch. 13.7 N, Column B, Line 2
4	Uncollectible Accounts			(1,975)	Appendix B page 1 Line 6
5	Depreciation & Amortization			(6,094)	Appendix B page 1 Line 14
6	Return on Equity			(14,017)	Appendix B page 1 Line 24
7	Total Revenues for CWC calculation		$	285,867	Sum of Lines 1 through 6
8	Total Return on Rate Base		$	-	
9	Percentage Equity			56.00%	ICC Staff Ex. 17.0, Schedule 17.1
10	Return on Equity		$	-	Line 8 times Line 9
11	O & M Expenses		$	36,796	Appendix B page 1 Line 19 minus Appendix B, page 1, Line 14
12	Pensions and Benefits			(4,765)	NS Ex. MJA-1.1, Company Schedule B-8, Page 1 of 2, Column H, Line 1
13	Payroll and Withholdings			(5,220)	NS Ex. MJA-1.1, Company Schedule B-8, Page 1 of 2, Column H, Line 2
14	Uncollectible Accounts			(1,975)	Appendix B page 1 Line 6
15	Inter Company Billings			(11,233)	NS Ex. MJA-1.1, Company Schedule B-8, Page 1 of 2, Column H, Line 3
16	Other Operations & Maintenance		$	13,603	Sum of Lines 11 through 15

F. Gas in Storage

1. Working Capital

Exception No. 5

Pages 26 to 27 of the Proposed Order should be modified as follows:

The discrepancy that Staff's witness perceived – that Peoples Gas had an inventory at Manlove higher than its planned withdrawals for the following season – does not lead to an automatic disallowance. 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, even though some of it has no doubt become base gas. Zack Sur., PGL/NS Ex.-TEZ 3.0 Rev, 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.

~~As an initial matter, the Commission notes that neither the arguments of the Utilities nor those of Staff, are models of clarity in dealing with the issue at hand. The Utilities appear to suggest that they are entitled to include in rate base the level of natural gas actually in storage during the test year, period. They fixate on the fact that the natural gas actually exists and that gas in storage is either top gas or base gas. And, the Utilities assert that they are allowed to include both top gas and base gas in rate base and, therefore, all gas in storage should be included in rate base.~~

~~In the Commission's view, it is true that natural gas can serve the function of either top gas or base gas and that by definition the gas in storage is either one or the other. The Utilities' idea that natural gas can~~

~~simply be converted from top gas to base and back again, is not a view that the Commission shares. As the Commission understands it, base gas is the quantity of gas in storage needed for a storage field to operate properly; that is, allow the top gas to be injected and withdrawn to meet the needs of utility customers. While the quantity of gas that is classified as base gas in subject to revision in some circumstances, it does not fluctuate as the Companies seem to suggest.~~

~~It appears that Staff has done the better job in focusing on the proper question before the Commission, i.e., whether the Utilities had more top gas in storage than was necessary to meet the needs of utility customers during the test year. The evidence of record appears to support the theory that due to warmer than normal weather during the test year, the Utilities did not withdraw as much top gas from storage as they would during a normal or colder than normal year. This does not indicate that the Utilities did anything wrong. It does explain; however, why they had more top gas in storage during the test year than is necessary to meet the needs of their customers. Contrary to what the Utilities suggest, they are not necessarily entitled to include in rate base all gas in storage.~~

~~In proposing its adjustment, Staff looked to the difference between the quantities of underground gas on hand at the end of the test year as opposed to other years. The Utilities contend that the test year was unusual. But, this is precisely why a historical review is necessary and we expect that Staff took the weather differences from this data into account when assessing whether the volume that is set out as working inventory in the test year is fairly representative of the volumes going forward. According to Staff, it is not.~~

~~In conclusion, the Commission finds that Staff has demonstrated that the Utilities had more top gas in storage than necessary to meet their customer needs. Thus we approve Staff's proposed downward adjustments to the working capital requirements of Peoples Gas and North Shore for gas in storage.~~

2. <u>Accounts Payable</u>

<u>Exception No. 6</u>

Page 31 of the Proposed Order should be revised as follows:

d) Commission Analysis and Conclusion

~~The Commission considers Staff's proposed adjustments to impose accounts payable offsets against the Gas in Storage in rate base and the Utilities' challenges to that proposal.~~

The Utilities maintain that while vendors arguably "finance" the storage gas, they pay vendors' invoices in no more than 16 days. ~~This is the main thrust of their argument.~~ The record establishes that the Utilities must, and do, pay these invoices, and that all of the invoices at issue here have been paid by the Utilities, based on the historical test year used in these proceedings. Staff's proposed adjustments unreasonably seek to deny the Utilities' return on substantial amounts of their actual historical investments in the Gas in Storage in rate base. Accordingly, the Commission finds that Staff's proposed adjustments to impose accounts payable offsets against the Gas in Storage in rate base lack merit and should not be approved.

~~In Staff's view, however, there is value to the Utilities during the term of those 16 days. Indeed, Staff considers the assertion that accounts payable are paid within sixteen days to confirm rather than disprove, that the accounts payable exist. Regardless of when the accounts payable were paid, Staff goes on to tell us, the fact remains that costs for gas in storage are continually being incurred and that there is a continual level of gas in storage that is supported by accounts payable. And, Staff asserts, the Utilities should not earn a return on that gas in storage.~~

~~We note too that what Staff asks be done in this instance is nothing new. In other words, there are a number of other cases where we made similar adjustments. The Utilities' attempts to distinguish these earlier situations from the present case are not convincing.~~

~~Staff bases the amount of its adjustment on accounts payable figures provided by the Utilities in a data request response. Staff Ex. 15.0 Corrected, Schedules 15.3 N and P at 2. While a more detailed discussion of Staff's methodology would have useful, we do not see the Utilities to present any challenges on Staff's calculation.~~

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

G. OPEB Liabilities and Pension Asset/Liability

Exception No. 7

Pages 35 to 36 of the Proposed Order should be modified as follows, or, in the alternative, as stated in Alternative A.

5. Commission Analysis and Conclusion

The Commission ~~agrees~~ does not agree with the positions asserted by GCI and Staff. Their arguments unfairly exclude Peoples Gas' net pension asset and North Shore's net pension liability, are not persuasive and ~~fully supported by~~ are contrary to the evidence. ~~Further, they have each established that the treatment we are being urged to assign to this item today, is the same the treatment that we adopted in a number of previous decisions. On all these grounds, the Commission accepts that a rate base deduction of $7,094,000 ($4,074,000 net of related deferred taxes) is required for the NS accrued OPEB liability and a rate base deduction of $55,653,000 ($31,570,000 net of related deferred taxes) is required for the PGL accrued OPEB liability in the determination of the Utilities' rate bases. *See* GCI Ex. 2.0 at 13.~~ Staff's citations to prior Commission orders addressing ratepayer-funded pension contributions are also inapposite. Accordingly, the Commission rejects GCI's and Staff's position, that OPEB liabilities should be deducted when calculating the Utilities' rate bases.

Alternative A

The Commission agrees, in part, with the positions asserted by GCI and Staff that the Utilities' OPEB liabilities should be deducted; however, for the reasons provided by the Utilities, Peoples Gas' net pension asset of $110,000,000 and North Shore's net pension liability of $24,000 also will be incorporated into the calculation of the rate bases.

~~The Commission agrees with the positions asserted by GCI and Staff. Their arguments are persuasive and fully supported by the evidence. Further, they have each established that the treatment we are being urged to assign to this item today, is the same the treatment that we adopted in a number of previous decisions. On all these grounds, the Commission accepts that a rate base deduction of $7,094,000 ($4,074,000 net of related deferred taxes) is required for the NS accrued OPEB liability and a rate base deduction of $55,653,000 ($31,570,000 net of related deferred taxes) is required for the PGL accrued OPEB liability in the determination of the Utilities' rate bases. *See* GCI Ex. 2.0 at 13.~~

~~But, we note that the underlying rationale for these adjustments is that such funds are supplied by ratepayers and not by shareholders such that shareholders are not entitled to earn a return on these funds. In fairness then, we need recognize the undisputed record showing that Peoples Gas and North Shore contributed $15,278,614 and $1,862,247, respectively, to the pension plans during the test year. We observe no discussion of or opposition to this particular recalculation that the Utilities propose on basis of their contribution. It appears to the Commission that recognizing these contributions is consistent with, but the converse of, the theoretical basis that we are applying here, i.e, these contributions are not ratepayer-funded.~~

~~The Commission finds that the Utilities' OPEB liabilities will be deducted, but, for the reasons provided by the Utilities, Peoples Gas'~~

~~contributions of $15,278,614 and North Shore's contributions of $1,862,247 to the pension plan also should be incorporated into the calculation of the rate bases.~~

I. Overall Conclusion on Rate Base

Exception No. 8

Pages 36 of the Proposed Order should be revised by correcting and updating the applicable figures, and adding parallel North Shore discussion, to reflect Exception Nos. 1 through 7.[1]

> Based on the gas utility rate base as originally proposed by Peoples Gas along with the conclusions *supra*, the gas utility rate base for Peoples Gas approved for purposes of this proceeding is $1,___,___,000. The rate base may be summarized as follows:

[1] While the Utilities believe that the Commission should adopt their Exceptions, they recognize that there are possible permutations of the Commission's rulings and, accordingly, the Utilities have not attempted to set forth all the possible resulting figures.

Peoples Gas Rate Base (in thousands)

Description	Rate Base
Gross Utility Plant	
Accumulated Provision for Depreciation and Amortization	
Net Plant	
Additions to Rate Base:	
Materials and Supplies	
Cash Working Capital	
Gas in Storage	
Budget Plan Balances	
Unamortized Rate Case Expense	
~~Pension Contribution~~	
Deductions From Rate Base:	
Accumulated Deferred Income Taxes	
Pre-1971 Investment Tax Credits	
Reserve for Injuries and Damages	
Customer Advances for Construction	
Customer Deposits	
~~Accrued Postretirement Benefits Other than Pensions ("OPEB")~~	
Rate Base	$ 1,___,___

Based on the gas utility rate base as originally proposed by North Shore along with the conclusions *supra*, the gas utility rate base for North Shore approved for purposes of this proceeding is $___,___,000. The rate base may be summarized as follows:

North Shore Rate Base (in thousands)

Description	Rate Base
Gross Utility Plant	
Accumulated Provision for Depreciation and Amortization	
Net Plant	
Additions to Rate Base:	
Materials and Supplies	
Cash Working Capital	
Gas in Storage	
Budget Plan Balances	
Unamortized Rate Case Expense	
~~Pension Contribution~~	
Deductions From Rate Base:	
Accumulated Deferred Income Taxes	
Pre-1971 Investment Tax Credits	
Reserve for Injuries and Damages	
Customer Advances for Construction	
Customer Deposits	
~~Accrued Postretirement Benefits Other than Pensions ("OPEB")~~	
Rate Base	$ ___,___

Alternative A

If the Commission were to accept Alternative A of Exception No. 7, then the text would need to be changed to reflect the resulting rate base figures and the same changes to the tables as above would be made, except that (1) in the Peoples Gas table, "Pension Contribution" would change to "Pension Asset" and the OPEB line would not be stricken; and (2) in the North Shore table, "Pension Contribution" would change to "Pension Liability" and the OPEB line would not be stricken.

III. OPERATING EXPENSES

B.5.i. Uncontested Issues – Administrative & General Expenses – Rate Case Expenses

Exception No. 9

On page 45 of the Proposed Order, "further abandon" should be changed to "withdrew".

C.3.b. Contested Issues – Administrative & General Expenses – Incentive Compensation Expenses

Exception No. 10

Pages 66 to 67 of the Proposed Order should be revised as follows, or, in the alternative, as provided in Alternative A:

(6) Commission Analysis and Conclusion

Before us on this issue are two conflicting views. While the Utilities assert that all parts of their incentive programs meet the standard for recovery, Staff, CUB and the AG would generally argue that none of these plans satisfy the test. As such, the Commission is put to the task of examining the record and applying its reasoned judgment informed by all of the relevant circumstances.

The record shows that there are as many instances where the Commission has approved incentive compensation as there are cases where such an expense has been denied. The main and guiding criterion is that the expense be prudent, reasonable and operate in a way to benefit the utility's customers. ~~It is in this light that we consider the particulars of the programs, the amounts paid out, to whom and why, and what this all means to the Utilities' customers.~~

~~We agree with Staff that three of the five plans (STIC, Affiliate Charges, Restricted Stock & Performance Shares) fail to demonstrate the cost saving or other direct ratepayer benefit that we require. While these plans may indeed be necessary "to attract and retain a qualified workforce" this is not reason enough to allow the expense. The remaining two plans, however, bring different concepts into focus.~~

Being a large utility means that management depends on the dutiful work performance of its ~~non-executive~~ employees. To motivate and maintain high standards, a utility may reasonably ~~believe that~~ offer incentive compensation ~~is~~ as the best way to match both employer and employee interests and ensure quality work performance. ~~And, when matters of customer service, customer satisfaction and the reduction of~~

~~operating expenses is at issue, it is incumbent upon the Commission to take a close and considered view. It is on this basis that we turn our attention to the Utilities' non-executive TIA and IPB Plans.~~ As such, incentive compensation is clearly a prudent expense, and one that stands to benefit a utility's customers.

The Commission finds that Peoples Gas and North Shore have demonstrated a steadfast commitment to incentive compensation that ensures they will continue to provide incentive compensation going forward. The record also shows that Peoples Gas' and North Shore's incentive compensation expenses are in the interests of their customers. The undisputed record demonstrates that, without incentive compensation, the Utilities could not continue to attract the talent necessary to provide safe, efficient and reliable service to customers. The record further demonstrates that incentive compensation benefits the Utilities' customers through: increased customer satisfaction; improved service reliability; more efficient, lower cost operations that lead to lower rates than would result from less efficient operations; improved employee performance; enhanced ability to attract and to retain high-quality employees; and better employee productivity. Finally, the record also shows that Peoples Gas' and North Shore's incentive compensation expenses resulted in tangible benefits to its customers, chiefly in the reduction of O&M expenses below target levels.

Peoples Gas' and North Shore's incentive compensation expenses are, in fact, reasonable and prudent. On this basis, the Commission finds that the Utilities are entitled to recover $5,376,000 and $576,000, respectively, of incentive compensation program costs and, therefore, the proposed adjustments of Staff and GCI are not approved.

~~The TIA Plan~~

~~This Plan applies to non-officer employees. As to its particulars, the Utilities' surrebuttal testimony effectively disputes Staff's claim that controlling O & M expenses should not count. It further shows that in the 2006 test year the aggregate actual O & M expenses were about $11 million below budget. Under the Plan, 25% of the measures were based on controlling these very expenses and we consider this as beneficial to ratepayers.~~

~~We further see that another 10% of the measures are tied to the number of phone calls made to the call centers. Even Staff recognizes the value of motivating this work. Further there is a measure of 10% associated with gas expenses and Gas Charges that we also believe should be counted. Finally, other unchallenged evidence of record confirms that 67.2% of the total payments were based on measures for controlling O & M expenses (48.4%) and call centers (18.8%). On this basis, the Utilities derive their alternative proposal.~~

~~IPB Plan~~

~~The IPB plan is also a non-executive program that is aimed at encouraging outstanding individual work. It is uncontested that the awards are not based on financial performances. The record shows that the IPB awards went to 426 different employees, and were paid out in an average amount of $2,884.53. Taken together, the goal of the plan, the large pool of potential awardees and the wide-reaching motivational impact, make it more likely than not, that ratepayers will benefit from the race to excellence.~~

~~We do not share Staff's concerns as to possible changes or discontinuances of these Plans . The Commission finds that Peoples Gas and North Shore have demonstrated a steadfast commitment to incentive compensation in that they recognize the value, if not the necessity, of providing incentive compensation going forward. We would expect that if changes were to occur, these would equally go to the benefit of ratepayers.~~

~~In the final analysis, the Commission concludes that Peoples Gas and North Shore should be allowed to recover $1,009,240 for Peoples Gas, and $94,024 for North Shore for costs associated with the operational measures of the "TIA" plan.~~

~~Further, we allow the amounts of $625,791 for Peoples Gas, and $53,107 for North Shore, under the "IPB" plan, which is tied to individual performance and not to any financial measures. These costs are reasonable and prudent, and we perceive them to benefit the Utilities' customers.~~

Alternative A

Before us on this issue are two conflicting views. While the Utilities assert that all parts of their incentive programs meet the standard for recovery, Staff, CUB and the AG would generally argue that none of these plans satisfy the test. As such, the Commission is put to the task of examining the record and applying its reasoned judgment informed by all of the relevant circumstances.

The record shows that there are as many instances where the Commission has approved incentive compensation as there are cases where such an expense has been denied. The main and guiding criterion is that the expense be prudent, reasonable and operate in a way to benefit the utility's customers. ~~It is in this light that we consider the particulars of the programs, the amounts paid out, to whom and why, and what this all means to the Utilities' customers.~~

~~We agree with Staff that three of the five plans (STIC, Affiliate Charges, Restricted Stock & Performance Shares) fail to demonstrate the~~

~~cost saving or other direct ratepayer benefit that we require. While these plans may indeed be necessary "to attract and retain a qualified workforce" this is not reason enough to allow the expense. The remaining two plans, however, bring different concepts into focus.~~

Being a large utility means that management depends on the dutiful work performance of its ~~non-executive~~ employees. To motivate and maintain high standards, a utility may reasonably ~~believe that~~ offer incentive compensation ~~is~~ as the best way to match both employer and employee interests and ensure quality work performance. ~~And, when matters of customer service, customer satisfaction and the reduction of operating expenses is at issue, it is incumbent upon the Commission to take a close and considered view. It is on this basis that we turn our attention to the Utilities' non-executive TIA and IPB Plans.~~ As such, incentive compensation is clearly a prudent expense, and one that stands to benefit a utility's customers.

The Commission finds that Peoples Gas and North Shore have demonstrated a steadfast commitment to incentive compensation that ensures they will continue to provide incentive compensation going forward. The record also shows that Peoples Gas' and North Shore's operational and non-financial incentive compensation expenses are reasonable, prudent and in the interests of their customers.

The Commission finds that Peoples Gas and North Shore should be allowed to recover (1) $1,009,240 for Peoples Gas and $94,024 for North Shore for costs associated with the operational measures of the "TIA" plan; (2) $625,791 for Peoples Gas and $53,107 for North Shore under the "IPB" plan, which is tied to individual performance and is not tied to financial measures; (3) $306,953 for Peoples Gas that was accrued as to the operational measures under the "STIC" plan; (4) $279,305 as to Peoples Gas (37.5% times $$744,812) plus $62,179 (27.5% times $165,811) as to North Shore that was accrued as to the operational measures for affiliate charges; and (5) $1,529,000 as to Peoples Gas for the restricted stock program, which is tied to providing competitive compensation packages. These costs are reasonable and prudent, they benefit the Utilities' customers, and they are tied to operational measures or, in the case of the "IPB" plan, individual performance and non-financial measures, and, in the case of the restricted stock program, non-financial measures.

~~The TIA Plan~~

~~This Plan applies to non-officer employees. As to its particulars, the Utilities' surrebuttal testimony effectively disputes Staff's claim that controlling O & M expenses should not count. It further shows that in the 2006 test year the aggregate actual O & M expenses were about $11 million below budget. Under the Plan, 25% of the measures were based~~

~~on controlling these very expenses and we consider this as beneficial to ratepayers.~~

~~We further see that another 10% of the measures are tied to the number of phone calls made to the call centers. Even Staff recognizes the value of motivating this work. Further there is a measure of 10% associated with gas expenses and Gas Charges that we also believe should be counted. Finally, other unchallenged evidence of record confirms that 67.2% of the total payments were based on measures for controlling O & M expenses (48.4%) and call centers (18.8%). On this basis, the Utilities derive their alternative proposal.~~

~~IPB Plan~~

~~The IPB plan is also a non-executive program that is aimed at encouraging outstanding individual work. It is uncontested that the awards are not based on financial performances. The record shows that the IPB awards went to 426 different employees, and were paid out in an average amount of $2,884.53. Taken together, the goal of the plan, the large pool of potential awardees and the wide-reaching motivational impact, make it more likely than not, that ratepayers will benefit from the race to excellence.~~

~~We do not share Staff's concerns as to possible changes or discontinuances of these Plans . The Commission finds that Peoples Gas and North Shore have demonstrated a steadfast commitment to incentive compensation in that they recognize the value, if not the necessity, of providing incentive compensation going forward. We would expect that if changes were to occur, these would equally go to the benefit of ratepayers.~~

~~In the final analysis, the Commission concludes that Peoples Gas and North Shore should be allowed to recover $1,009,240 for Peoples Gas, and $94,024 for North Shore for costs associated with the operational measures of the "TIA" plan.~~

~~Further, we allow the amounts of $625,791 for Peoples Gas, and $53,107 for North Shore, under the "IPB" plan, which is tied to individual performance and not to any financial measures. These costs are reasonable and prudent, and we perceive them to benefit the Utilities' customers.~~

I. Overall Conclusion on Operating Expense Statements

Exception No. 11

Pages 71 to 75 of the Proposed Order should be revised to reflect the direct and derivative impacts of Exception Nos. 9 and 10 and the derivative impacts of Exception Nos. 1 through 8 and 12 through 14. See also Exception Nos. 29 through 31.[2]

IV. RATE OF RETURN

C. Cost of Common Equity

Exception No. 12

Corrections to Presentation of Parties' Positions

The sixth full paragraph of Section IV.C.1.(a) on pages 78-79 of the Proposed Order should be corrected as follows:

> The Utilities acknowledge past Commission decisions rejecting the ~~financial leverage~~ "market-to-book" adjustment to DCF results, and they say they are not proposing to change this practice. Rather, in developing the market-required return, the Utilities urge us to take the increased financial risk of the book value capital structure into account when using the market-required rate of return on common equity. They request that we ~~re~~consider their proposed "financial ~~risk~~ leverage" adjustment, its theoretical underpinnings, and the evidence in this record that applying ~~the DCF~~ market model results to book value capitalization will underestimate the investor's required return. *Id*. at 73.

Section IV.C.2. on page 81 of the Proposed Order should be corrected as follows:

> **2. Staff's Position**
>
> Staff ~~estimates PGL's investor-required rate of return on common equity to be 9.70%~~ estimated the Utilities' market-based cost of equity based on the Utility Sample to be 9.79%. Staff applied the DCF and CAPM to the sample of gas utilities that Mr. Moul used in his estimate of return on common equity. Staff

[2] While the Utilities believe that the Commission should adopt their Exceptions, they recognize that there are possible permutations of the Commission's rulings and, accordingly, the Utilities have not attempted to set forth all the possible resulting figures.

witness Kight-Garlisch believes that Mr. Moul's sample Utilities are reasonable operating risk proxies for PGL and NS.

Staff estimates PGL's investor-required rate of return on common equity to be9.70%, while its ~~Ms. Kight-Garlisch's~~ recommended cost of common equity for NS is 9.50%~~, using essentially the same analysis and arguments she used for PGL~~. ~~However,~~ Staff's revenue requirement recommendations, including its cost of common equity recommendation, indicate a level of financial strength commensurate with an AA- credit rating for PGL and an AA credit rating for NS, compared to an average credit rating of A for the Utility Sample. ~~Thus, the differences in financial strength between the two Utilities produced different cost of common equity recommendations.~~ In order to reflect this difference in financial risk, Staff

~~For NS, Ms. Kight-Garlisch~~ adjusted the results of ~~her~~ its Utility Sample cost of equity estimate, 9.79%, downward by ~~2~~9 basis points for PGL and by 29 basis points for NS (the spread between A rated and AA rated 30-year utility debt yields). ~~Thus, Ms. Kight-Garlisch's recommended cost of common equity for NS is 9.50%.~~

Staff emphasizes that the difference between the results of Mr. Moul's averaged unadjusted CAPM and DCF analyses ~~(excluding his adjustments)~~ and ~~Staff's~~ Ms. Kight-Garlisch's averaged unadjusted CAPM and DCF analyses is only 11 basis points. The Utilities argue that the proximity of the averages is a meaningless coincidence, and diverts attention away from the wide disparity between Staff's CAPM and DCF results. Staff claims that the major differences between the Utilities' and Staff's cost of common equity recommendations result from Mr. Moul's adjustments to the Utility Sample's cost of common equity. Mr. Moul adjusted his results because the market-value based common equity ratios of his sample are higher than the book-value based equity ratios for the Utilities. He also made an adjustment for flotation costs. Ms. Kight-Garlisch adjusted her Utility Sample cost of common equity to reflect her view of the lower financial risk of the Utilities compared to the Utility Sample.

The third paragraph of Section IV.C.2(a) on pages 81 and 82 of the Proposed Order should be corrected as follows:

Staff also contests the Utilities' assertion that Staff's application of the DCF model is flawed because the results for some Utilities in the utility sample are too low. Staff says its recommendation is based upon a representative sample, rather than any individual company's estimate, because estimates for a whole sample are subject to less measurement error. In Staff's view, eliminating utilities on the basis of their individual DCF results without regard to the effects of such action on the overall sample is improper, because it would defeat the purpose of using a sample. Staff states that removing the two utilities Mr. Moul complains about would reduce the sample to six, and, all else equal, a larger sample better mitigates the potential measurement error of the individual company cost of common equity estimates[13]. In addition, Staff asserts that Mr. Moul singled out utilities in the sample with "low" results. Staff Rep. Br. at 28-29. The Utilities counter that Staff misinterprets their criticism, and that they are not proposing to remove certain results from Staff's DCF analysis. Rather, the Utilities contend that the existence of results that approach and even fall below the utility cost of debt means that there is something seriously wrong with Staff's DCF analysis altogether. Utility Init. Br. at 75-76.

[13/] Staff states that if the Commission deems it appropriate to remove Nicor and Atmos Energy from the DCF analysis as outliers, the CAPM analysis would reduce its estimate of the cost of common equity from 11.34% to 10.91%. Staff Rep. Br. at 29-30.

Section IV.C.2(c) on page of the Proposed Order should be corrected as follows:

c) Adjusted Results

Based on her DCF and ~~risk premium~~ CAPM analyses, Staff witness Kight-Garlisch estimated that the cost of common equity for the Utility Sample is 9.79%. To determine the suitability of that cost of equity estimate for NS and PGL, she compared the risk level of the Utility Sample to PGL and NS. *Id*. at 54. She concluded that ~~PGL's~~ Utilities' financial strength is greater than the Utility Sample's A average credit rating, which indicates that ~~PGL has~~ Utilities have less financial risk and thus less total risk than the sample. Since investors require lower returns to accept lower exposure to risk, she adjusted the 9.79% Utility Sample's investor-required rate of return downward to 9.70% for PGL and to 9.50% for NS (for the ~~9 basis point~~ spread between A rated and AA- rated 30-year utility debt yields). *Id*. at 56.

Staff adds that it is appropriate to adjust the cost of common equity for ~~PGL~~ to reflect a credit rating of AA- and for NS to reflect a credit rating of AA, not only because the benchmark financial ratios that result from Staff's proposed revenue requirements are those of a company with ~~an AA-~~ such credit ratings, but also because ~~PGL's~~ the Utilities' affiliation with unregulated or non-utility entities lowered ~~its~~ their credit ratings. On September 26, 2002, Standard and Poor's downgraded PGL and NS to A- ~~from AA-~~. Staff says the downgrade resulted from ~~PGL's~~ the Utilities' parent company's "increasing business risk with the growing share of nonregulated business." *Id*. at 56-57.

Section 9-230 of the Act prohibits the Commission from including in rates the incremental risk or increased cost of capital resulting from a utility's affiliation with unregulated or non-utility Utilities. Staff argues that since ~~PGL's~~ the Utilities' A- credit rating is a function of ~~it's~~ their affiliation with unregulated or non-utility ~~Utilities~~ business activities, the cost associated with that credit rating cannot be reflected in ~~PGL's~~ the Utilities' rates. Staff claims that its downward adjustment to the cost of common equity of the Utility Sample addresses the requirements of Section 9-230. *Id.* at 57-58

Section IV.C.4. at pages 86-87 of the Proposed Order should be corrected as follows:

4. All Parties – Market to Book Value

The Utilities adjust their market-based DCF and CAPM models for ~~application to book value, by multiplying the result of a financial model by the utility's market-to-book-ratio~~ the "mismatch" between the lower financial leverage and risk associated with the financial model results and the higher financial leverage and risk associated with the proxy group's book value capital structure used for ratemaking purposes. The Utilities state that the costs of equity produced by the financial models are based on the market value capitalizations of the utility sample. The sample's market value capitalizations contain more equity and less financial risk than its book value capitalizations used for ratemaking purposes. The Utilities argue that applying a market-based cost of equity to a book value capital structure yields a mismatch in the financial risks reflected in the two. If a return on equity based on a lower amount of financial risk is applied to a utility's book value capital structure, the utility's earnings will by definition be insufficient to allow the utility to achieve the authorized return.

Staff contends such adjustments are based on the incorrect notion that utilities should be awarded rates of return on common equity in excess of investor-required return whenever their market values of common equity exceed book values. Staff Init. Br. at 61. Staff says there are two possible explanations for how utility stock prices have come to exceed their respective book values: 1) the investor-required rate of return has fallen; or 2) expectations of future earnings have risen. Either way, Staff contends, if a utility's stock price grows to exceed its book value due to a decline in investors' required rate of return for that utility, a lower rate of return should follow. *Id*. at 62.

According to Staff, it is unwise to allow a utility to earn a rate of return on rate base equal to the product of its market-to-book ratio and the market required rate of return on common equity becomes apparent when those other sources of value are recognized. That would produce an unending upward spiral as each successive increase in market value would lead to another increase in the allowed rate of return, which in turn, would lead to a further increase in market value. Staff Init. Br. at 64-65.

The Utilities contend that Staff has mischaracterized their financial leverage adjustment as a "market to book" adjustment of the type the Commission has considered and rejected in previous cases. The Utilities assert that a market price above book value is necessary to maintain the financial integrity of shares previously issued and to avoid dilution when new shares are offered. The Utilities also argue that Staff has taken contradictory positions with respect the reasons why a utility's market-to-book ratio may be greater than one, and that such a ratio does not refute the need for their proposed financial leverage adjustment. City/CUB say there is no dispute that the Utilities currently enjoy market-to-book ratios far above 1.0, and assert that the premium reflected in that market-to-book ratio provides access to additional capital without diluting existing shares. City/CUB Init. Br. at 50. The Utilities and Staff respond that a market-to-book ratio of greater than 1.0 can be due to many factors besides the utility's authorized return on equity.

While acknowledging the multiple theoretical reasons for a market-to-book ratio above 1.0, City/CUB underscore the one reason evident here - the Utilities' earnings in excess of their authorized return levels for several years since their previous rate case. In contrast, City/CUB argue, there is no evidence that incentive return awards from this Commission, rewards for excellent management, or market inefficiencies have affected the Utilities' market-to-book ratio. Accordingly, City/CUB maintain that Mr. Moul's leverage adjustment to perpetuate that ratio is unsupportable. City/CUB Rep. Br. at 29.

Nonetheless, Staff also asserts that Mr. Thomas' market-to-book-value analysis is based on the over-simplified premise that a utility should precisely earn its cost of capital on a continuing basis. Staff insists that many ratemaking practices can result in a utility's market value exceeding its book value. Thus, Staff avers that a market-to-book-ratio in excess of one does not necessarily mean the authorized rate of return is too high. Staff Init. Br. at 72-73.

The third paragraph of Section IV.C.6. on page 69 of the Proposed Order should be revised as follows:

Moreover, Staff contends, given the financial strength implied by the Utilities' forecasted financial ratios, it would expect the Utilities' required return on common equity to be considerably lower than average. Staff notes that its recommendations of 9.5% for NS and 9.7% for PGL are ~~as close to~~ below the 10.49% average allowed by U.S. regulatory commissions in 2006 ~~as~~ while the Utilities' return request of 11.06% is above the average. In any event, Staff says, the Commission has rejected this type of comparability in ComEd's most recent delivery services docket. *Id*. at 30-31.

Exception No. 13

Section IV.C.8. at pages 91-95 of the Proposed Order should be revised as follows, consistent with the Utilities' Brief on Exceptions:

8. Commission Conclusions

As we have noted previously, these are the Utilities' first general rate cases since 1995 and the first since Integrys acquired the Utilities earlier this year. The Commission's task is to set a utility's rates at a level required to maintain its financial integrity, which we define as a condition wherein a company has sufficient financial strength to raise needed capital in good and bad markets at reasonable costs and with rates to customers and rates of return to stockholders that are fair. In setting the Utilities' cost of equity, we take into consideration their recent acquisition by Integrys and its compliance to date with the conditions we placed on the acquisition in Docket 06-0540.

We begin our analysis by examining the parties' financial models. The Utilities used DCF, CAPM and risk premium models. Staff employed the DCF and the CAPM. City/CUB relied primarily on the DCF model and used the CAPM to verify the results.

The Commission has typically relied on the DCF and CAPM models in establishing utility authorized returns on common equity. We do not find City/CUB's arguments against the CAPM persuasive. In many prior proceedings, the Commission has regarded the CAPM as a useful tool based upon sound financial theory. As the Utilities and Staff indicate, investors are only rewarded for accepting systematic risk. That is, any risk that an investor can eliminate by holding a diversified portfolio of securities need not be reflected in the investor's required return.

The Commission understands that the CAPM is similar to a risk premium model. However, the risk premium model that the Utilities used in addition to their CAPM is unhelpful. The primary reason that the Commission has repeatedly rejected that type of risk premium analysis is the difficulty in establishing the "correct" risk premium. The risk premium for common equity relative to debt changes over time and, in the Commission's view, there is no objective manner in which to establish that risk premium. While all cost of equity analyses require the application of judgment, this particular approach is primarily a matter of judgment and we are unwilling to rely on such a subjective analysis.

City/CUB used an annual version of the DCF model and objects to the quarterly version used by the Staff and the Utilities. The Commission finds that the quarterly version of the DCF model is superior. We remain convinced, as we have been in numerous previous rate cases, that the annual version of the model should be used to correctly reflect the time sensitive value of the dividends reflected in the DCF model. Mr. Thomas' arguments, which the Commission has considered in previous cases, have not altered our view..

While Mr. Thomas did not explicitly rely on his CAPM results in developing his recommended return on common equity, he did claim it supported his DCF results. The Commission rejects Mr. Thomas' suggestion that unadjusted or raw betas should be used as inputs to the CAPM. As both the Utilities and Staff point out, the financial literature and empirical studies support the use of adjusted betas as better forward-looking measures of systematic risk. We have regularly relied upon adjusted betas in establishing authorized returns on common equity and the arguments of City/CUB have not convinced us to change this practice.

Mr. Thomas also objects to the manner in which the Utilities and Staff developed their expected market risk premium for use in the CAPM. As with the risk premium between utility cost of debt and cost of common equity, discussed above, the expected market risk premium relative to the risk free rate is not stable over time. As a result, the Commission concludes it is preferable to rely upon a current estimate of the expected market risk premium rather than upon an approach derived from academic research.

Staff states that (excluding ~~Mr. Moul's~~ all adjustments), the difference between the Utilities' CAPM and DCF analyses and its own is 11 basis points. This is a meaningless comparison because it is the product of simple averaging of Staff's and the Utilities' results, and the wide disparity between Staff's CAPM and DCF results of over 300 basis points is troubling.

The Utilities have raised significant concerns with Staff's longstanding practice of basing its financial models on stock price and dividend data from a single day. The Utilities note that the practice relies on a degree of efficiency in the stock market which may not exist, and they reasonably question the usefulness of "current" stock market data that is months old by the time of the hearing and the Commission's decision in rate cases. The Utilities point to results in Staff's DCF analysis that approach and even fall below the utility cost of debt. The Commission agrees that such results indicate something amiss with Staff's data or its model, or both, and that Staff has not explained how such results could be generated by a properly applied model with appropriate data. Because of these evidentiary shortcomings, the Commission finds that Staff's DCF results do not provide a reasonable basis for the Utilities' cost of equity in this case. Although Staff relied on similar data for its CAPM model, its CAPM results appear to be within a range of reasonable returns. Therefore, the Commission concludes that the Utilities' cost of equity in this case should be based on the unadjusted results of Staff's CAPM model and the Utilities' DCF and CAPM models.

~~Thus, Mr. Moul's financial leverage adjustments require discussion.~~ The Utilities propose a "financial leverage" adjustment to the market model results that this Commission has previously not considered. The Utilities support the adjustment so that the authorized return applied to the Utilities' book value capital structures represents the investor required return. They maintain that the costs of equity produced by the financial models are based on the market value capitalizations of the utility sample. They further assert that the proxy group's market value capitalizations contain more equity and less financial risk than its book value capitalizations used for ratemaking purposes, which contain less equity and more financial risk. The Utilities argue that if one applies a market-based cost of equity to a book value capital structure there is a mismatch in financial risks, which if not corrected will prevent the Utilities from earning their authorized returns, assuming all other factors affecting utility earnings to be equal.

The book value capital structure reflects the amounts of capital a utility actually utilizes to finance the acquisition of assets, including those assets used to provide utility service. In establishing the overall or weighted average cost of capital, the Commission's historical practice has been to multiply the proportion of common equity, based on the book value capital structure, ~~is multiplied~~ by the market required return on common equity. ~~The Commission has used this approach in establishing utility rates for at least twenty-five years.~~ But based on the Modigliani-Miller theorem that a firm's cost of equity varies with the amount of debt in its capital structure, this practice may not provide a utility with an opportunity to earn its authorized return, regardless of whether a utility's market-to-book ratio is greater than 1.0. Staff agrees with the Utilities that there are many factors that affect a utility's earnings besides its authorized return on equity. Holding all of these other factors equal, it follows from the Modigliani-Miller theorem that if a market-based cost of equity that is based on a capital structure with more equity and less risk is applied to a book value cost of equity with less equity and more risk, the result is an revenue requirement that by definition will prevent the utility from earning its authorized return. Such a result would be unlawful. A public utility must be provided with an opportunity to earn its authorized return. *Illinois Bell Tel. Co. v. Illinois Commerce Comm'n,* 414 Ill. 275, 286, 111 N.E.2d 329, 335 (1953).

Accordingly, the Commission accepts the Utilities' financial leverage adjustment to the market-based cost of equity for application to the utility's book value capital structure for ratemaking purposes. In this case, no party disputed the accuracy of Mr. Moul's specific adjustments of 52 basis points to his DCF model and 106 basis points to his CAPM model.

~~In the Commission's view, the Utilities have failed to establish why a mismatch between the financial risk reflected in the book value and market value capital structures is problematic. If the Utilities were correct that regulatory commissions, including this one, have been understating the market required return on equity for twenty-five years, then the market values of common equity for utilities would not have remained well above the book values during that time. A practice of routinely understating the market required return on common equity would have surely driven down the market values of common equity to near book value, but that has not happened. Accordingly, the Commission does not agree that an adjustment to the market required return on common equity is necessary to reflect the difference in financial risk between book value and market value~~

~~capital structures. Therefore, we reject Mr. Moul's financial leverage adjustment to his DCF results and his proposal to impose a similar leveraging adjustment to the betas used in his CAPM analysis.~~

~~Having rejected the Utilities' financial leverage adjustment, we return to the spread (11 basis points) between the Utilities' DCF and CAPM results and Staff's. The slight difference is attributable primarily to differences in stock prices, growth rates and beta estimates. In the Commission's view, these DCF and CAPM results of the two witnesses are unusually similar. However, on matters such as stock prices and betas, Staff's witness has utilized input data derived from processes similar to those adopted by the Commission in many previous proceedings. While the Utilities urge the Commission to reconsider its earlier conclusions, the close similarity of the two witnesses' results indicates that a change in Commission practice is unwarranted. Consequently, the Commission finds that the outcome of Staff's DCF and CAPM analyses for the proxy utility sample, 9.79%, is the most reasonable of those presented.~~

Staff witness Kight-Garlisch made downward adjustments to the cost of equity results to reflect her view that PGL and NS each have less financial risk than the proxy utility sample. The Utilities disagree and urge the Commission to reconsider its past practice of accepting such adjustments. The Utilities argue, in essence, that their own proxy utility sample is similar in total risk (operational and financial risk) to both PGL and NS. They assert that because their sample was selected on the basis of total risk, not just operational risk, a financial risk adjustment is unnecessary and inappropriate. Staff says it accepted that the utility proxy sample had operational risk that was similar to the Utilities', but did not evaluate the similarity of financial risk until after the cost of equity analysis was performed on the sample.

The Commission notes that in selecting his proxy sample, Mr. Moul did endeavor to consider financial risk, including comparing credit ratings. However, ~~the Utilities failed to address an important issue raised by Staff - that the Utilities' credit ratings have been impacted by non-regulated activities.~~ Section 9-230 of the Act requires the Commission to ensure that such activities are not reflected in the authorized rate of return. ~~While the Utilities agreed an adjustment to the embedded cost of debt was necessary to remove the impact of non-regulated activities, their recommended return on common equity does not appear to reflect such an adjustment.~~

~~By performing its financial ratio analysis on the regulated entities, Staff has been able to isolate their financial risk. Staff's analysis thus demonstrates that the Utilities are less financially risky than the proxy utility sample and that downward adjustments to the cost of equity results for that proxy sample are necessary.~~ Staff's adjustment is theoretically sound and consistent with similar adjustments accepted by the Commission in previous rate cases. The Utilities do not challenge Staff's premise, but take three issues with the its implementation.

First, Staff's adjustment assumes that only the Utilities' credit ratings are affected by non-utility risk, whereas none of the proxy group company's credit ratings are so affected. Staff recognized that the financial risk of some members of the proxy group is affected by such risk, and adjusted their S&P Business Profile scores, but inexplicably did not adjust those companies' credit ratings for purposes of its financial risk adjustment. This methodological flaw is fatal to Staff's adjustment. According to Staff's premise, the credit ratings of those proxy group members would need to be increased by some degree to reflect their higher non-utility risk. This would have reduce the differences between the proxy group's and the Utilities' credit ratings and, presumably, the size of Staff's adjustments.

Second, the Utilities reason that if a party is going to take issue with the risk comparability of a utility proxy group, the party should not be allowed to isolate one type of risk for differences without analyzing whether there are offsetting differences associated with other types of risk. Here, even if Staff had successfully isolated the Utilities "financial risk" for comparison to the proxy group using actual and hypothetical credit ratings, Staff did not show that the difference in financial risk was not offset by differences in the myriad other types of risk considered in assembling the proxy group.

Third, in its analysis, Staff increases the Utilities credit risk ratings from A- to AA- (PGL) and AA (NS). This is precisely the same degree of disparity that caused the Commission to find that the record did not support Staff's financial risk adjustment in *Central Illinois Light Co. d/b/a AmerenCILCO, et al.,* Dockets 06-0070, 06-0071, 06-0072 (Cons.), at 146 (Order, Nov. 21, 2006).

For these reasons, the Commission concludes that Staff's specific financial risk adjustments to the Utilities' market-based cost of equity , though theoretically sound, are not reasonable.

Staff and the City/CUB argue that in the event the Commission approves the various riders proposed by the Utilities, a downward adjustment to the cost of common equity should be made. They assert that the proposed riders would reduce the riskiness of the Utilities, which should be reflected in the authorized return on common equity. The Utilities disagree, asserting that some of the utilities in the proxy sample have similar types of riders.

While Mr. Thomas has offered a method for quantifying the impact of the proposed riders on the Utilities, the Commission believes that the cost of common equity analysis is an integrated process and great care should be taken in making ad hoc adjustments to the cost of common equity. Given that both the City/CUB and Staff witnesses performed cost of equity analyses on a proxy utility sample, any adjustment to the computed cost of equity would more properly reflect any difference in risk between the proxy utility sample and the target utility company. This is essentially the manner in which Staff's leverage adjustment, which is discussed immediately above, was developed. Mr. Thomas' adjustment does not quantify the difference in risk between the proxy utility sample and the Utilities. While the Commission does not dismiss the intention underlying Staff's and City/CUB's recommendation, the record does not contain sufficient information to justify and quantify the type of adjustment that those parties advocate.

Based upon its review of the record, and consistent with the conclusions above, the Commission finds that ~~PGL's~~ Utilities' cost of common equity ~~is 9.70% and the NS's cost of common equity is 9.50%~~ can be reasonably estimated by averaging the Staff's CAPM result with the Utilities' DCF and CAPM results adjusted for financial leverage. The resulting cost of equity, exclusive of flotation costs, is 10.91%. Because of the proximity of this result to the Utilities' requested cost of equity of 11.06%, we find that the Utilities' request is reasonable.

Taking into consideration the Commission's conclusions regarding, capital structure, cost of long-term debt, and cost of common equity the Commission finds that Peoples Gas should be authorized to earn a rate of return of ~~7.48~~ 8.24% on its rate base and that North Shore should be authorized to earn a rate of return of ~~7.69~~ 8.56% on its rate base. The tables below show the calculation of those authorized rates of return:

Peoples Gas

Component	Percentage	Cost	Weighted Cost
Long-term debt	44.00%	4.67%	2.05%
Common equity	56.00%	~~9.70~~ 11.06%	~~5.43~~ 6.19%
Total	100.00%		~~7.48~~ 8.24%

North Shore

Component	Percentage	Cost	Weighted Cost
Long-term debt	44.00%	5.39%	2.37%
Common equity	56.00%	~~9.50~~ 11.06%	~~5.32~~ 6.19%
Total	100.00%		~~7.69~~ 8.56%

F. Weighted Average Cost of Capital

Exception No. 14

Section IV.E. on page 97 of the Proposed Order should be revised as follows:

1. Peoples Gas

As we stated in connection with PGL's return on common equity, PGL's approved weighted average cost of capital is ~~7.48~~ 8.24%, including 4.67% long term cost of debt and ~~9.7~~11.06% return on common equity.

2. North Shore

As we stated in connection with NS's return on common equity, NS's approved weighted average cost of capital is ~~7.69~~8.56%, including 5.39% long term cost of debt and ~~9.5~~11.06% return on common equity.

V. HUB SERVICES (ALL ISSUES RELATING TO HUB SERVICES)

Exception No. 15

The Proposed Order on page 113, in its final paragraph, contains a typographical error. "$34,857,000" should be changed to "$39,019,000".

VI. WEATHER NORMALIZATION

Exception No. 16

The Proposed Order on page 119 should be modified as follows:

> Based on the foregoing evidence, the Commission is willing to approve the Utilities' predictive approach for setting rates in these dockets. While our traditional "most likely ambient conditions" formula, based on 30 years of data, has not prevented the Utilities from earning their allowed return in most years, that does not mean that it was ever an optimal mechanism, or that it remains so today. To the contrary, the Utilities' evidence suggests that it was sub-optimal, and getting more so in an incrementally warming climate. *E.g.*, PGL-NS Marozas Ex. 1.0 at 4. Thus, while we would have expected 30-year data (based on the general statistical principle that more data regarding varying conditions is better than less) to identify the ambient conditions most likely to occur, record

evidence does not show that such conditions, in fact, occurred with sufficient frequency to adhere to past methodology. It should be kept in mind that we are asking weather data to do something they were not gathered for – to match actual future revenue to allowed future revenue, over an indeterminate period of years. In Nicor and in the present cases, we have been prodded to improve this process. The Utilities' predictive scheme appears to be an improvement and we will adopt it and subject it to the test of time. Therefore, the Commission approves weather normalization based on 10 years of data as proposed by the Utilities.

~~The Commission does not agree, however, that the Utilities' 10-year data set is the optimal choice for rate-setting. The Utilities' rationales for selecting that time frame ("rounding" and consistency with Nicor) do not make up for the greater predictive accuracy apparently associated with 8- and 12-year data. Therefore, the Commission approves weather normalization based on 12 years of data, which we prefer to the 8-year interval because 12 years will include both the atypically cold weather of 1996 and the warmest weather of 1998. PGL-NS Marozas Ex. 1.0 at 6. The Commission cannot know how long the rates established here will remain in effect, but we do know that the Utilities' current rates have prevailed for 12 years.~~

~~Additionally, we will require the Utilities to use the most recent 12 years, including 2007. The Utilities have demonstrated that northern Illinois' climate is trending incrementally warmer. Consequently, the most relevant 12-year data will presumably be the most recent~~.

VII. NEW RIDERS

B. Riders VBA and WNA

1. Rider VBA

Exception No. 17

The Proposed Order on page 132-133 should be modified as follows:

f. Commission Analysis and Conclusion

This case presents the Commission with its first introduction to decoupling mechanisms and it is being presented here with proposed Rider VBA. In simplest form, Rider VBA would adjust customer prices under Service Classifications Nos. 1N, 1H, and 2, and in a way that the Utilities revenues are held constant despite changes in customer consumption. Such changes are brought about by rising natural gas prices, the call for conservation measures, warming weather trends, the involvement of the Utilities in gas efficiency programs, and other events. These adjustments between rate cases are symmetrical meaning that they are based on both the over-recovery as well as the under-recovery of target revenues. Implementing Rider VBA imposes some additional administrative expenses and, among other things called for by Staff, there would be annual internal audits.

The question raised by Staff and the GCI parties is whether Rider VBA is legal, i.e., whether it is the type of mechanism that the Commission has authority to adopt. We note that the use of riders is appropriate when there are costs at issue and these are either unexpected, or volatile or fluctuating. We do not agree~~ with Staff~~, that Rider VBA is fundamentally different from any other rider that the Commission has authorized thus far and which the courts have approved. At the very outset, the subject of Rider VBA is revenues and not costs.~~ And~~ We concede that in the only instance where revenue recovery was at issue, the Court struck down the rider. *A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993). But the facts and circumstances there were of a much different nature and ~~require a different analysis. In any event, we pass the question and move to matters that drive our decision in the matter.~~as will be discussed below, *Finkl* does not preclude us from approving a rider that involves the recovery margin revenues. There is nothing that supports the conclusion that Rider VBA is fundamentally different than any rider that has been authorized by the Commission. In addition, the record in this case is sufficiently developed to enable the Commission to determine that Rider VBA is appropriate for the Utilities' system in view of the particulars of declining and variable customer usage patterns and the accompanying revenue recovery impacts for Peoples Gas and North Shore Gas. We find that the evidence establishes that the Utilities' usage patterns and margin recovery fluctuations justify a decoupling rate design,.

~~We observe the Utilities to contend that decoupling mechanisms, like Rider VBA, are being implemented by state commission across the country~~

~~In our view, however, it is not enough to know that other jurisdictions have accepted de-coupling mechanisms. We need to know the particulars and the experience of their implementation. Based on what Staff tells us, the state commissions that have approved decoupling mechanisms have done so with great apprehension, after thorough investigation and testing, and often at the behest of the legislature. These states have adopted revenue decoupling mechanisms, but either as pilot program, with safeguards, or both. In contrast, Staff informs, the instant Rider VBA does not have, nor have the Utilities proposed, any safeguards to protect the ratepayers.~~

~~This alone makes Rider VBA unacceptable to the Commission. In rejecting Rider VBA, it is reason enough to know that there are potential ways to protect customers and that these have not been discussed or incorporated into the proposal at hand. To be sure, this Commission will do no less for its~~

~~ratepayers than has been done in other states. As such, we find the presentation by the Utilities is nowhere sufficient in these premises.~~

~~We do not minimize the Utilities business challenges in this term of high gas prices and the various responses being undertaken. In our view, however, and on the record, the urgency to act on a decoupling mechanism such as Rider VBA proposal is not yet upon us. The Utilities are in the midst of a rate case that should bring about significant effects through rate design and weather normalization changes. Considered another way, neither the Utilities nor this Commission know the actual results of the changes that we are implementing today. Another possible change that weighs heavily on the Commission in this case, is the proposal for an energy efficiency plan. While the AG and City-CUB make not much of effort or the amounts involved, we view this proposal as ground-breaking and in the best possible way.~~

While the *Finkl* case rejected the particular rider at issue there, the fact that the rider in question would recover revenues was neither argued nor decided. *Finkl* involved a proposal by Commonwealth Edison to recover lost revenues pertaining to a demand-side management program in a proposed Rider 22. The Court rejected Rider 22 because it found that the costs associated with the lost revenue were not "unexpected, volatile or fluctuating expenses which Edison cannot control". *Finkl*, 250 Ill. App. 3d 32 at7. There was no rejection of Rider 22 in *Finkl* because it involved "revenues". Indeed, the *Finkl* Court did not seem concerned at all that Rider 22 involved lost revenues and the Court mentions this feature numerous times in the decision without criticizing or rejecting that aspect of Rider 22. Rather, the Court focused on the incremental expenses associated with the demand-side management program and not the lost revenue aspect of Rider 22 and this interpretation has been articulated subsequent to the *Finkl* decision. In *CILCO v. ICC*, 255 Ill. App. 3d 876, 884-885, 626 N.E.2d 728 (3rd Dist. 1993), the Court noted:.

> In *Finkl* . . . the Court . . . found that demand-side management expenses were not of such a nature as to require rider treatment . . .

In Commission ratemaking and rider cases in particular, the Illinois Supreme Court has upheld our broad discretion to employ riders and to make appropriate pragmatic rate adjustments. In the *City of Chicago v. Illinois Commerce Commission*, 13 Ill.2d 607, 150 N.E.2d 776 (1958) ("*City of Chicago I*"), the Court unambiguously held that the Public Utilities Act (PUA) gives us broad authority to approve rates that are not fixed and that change from time to time, *i.e.*, the authority to approve riders:

> It is clear that the statutory authority to approve rate schedules embraces more than the authority to approve rates fixed in terms of dollars and cents. The Public Utilities Act, taken as whole,

> contemplates that a rate schedule may contain provisions which will affect the dollar-and-cents cost of the product sold.

Id., 13 Ill.2d at 611. The *City of Chicago I* Court did not restrict our discretion to adopt automatic rate adjustment provisions and acknowledged that the General Assembly recognized the need for the Commission to have broad authority in setting rates that adjust in the future:

> The General Assembly has * * * recognized that rate schedules consist not merely of lists of rates in dollars and cents, but that they customarily include provisions that will in various ways affect the rates charged at the time of filing or to be charged thereafter.

13 Ill. 2d at 613 (citing *City of Norfolk v. Virginia Electric & Power Co.*, 197 Va. 505, 90 S.E.2d 140, 148 (1954)).

No authority involving riders has placed limitation on our authority to approve riders because a rider might involve the recovery of revenues, as opposed to costs or expenses. There is simply no requirement in Illinois law that the items for recovery under an adjustment clause (rider) be expressed as "costs". The dispositive fact is that the item for recovery is part and parcel of a "rate" established by the Commission. Rates are simply charges that are derived from a consideration of costs and expenses incurred by the utility which are collected in a revenue stream that is measureable and defined. The expression of Rider VBA charges as revenues does not in any way change the essential character of the charges as rates which may be the subject of an automatic adjustment or rider. There is simply nothing that restricts our approval of the recovery of "margin revenues" or any other element of a utility's rates in a rider. Thus, there is no legal basis for rejecting Rider VBA because it seeks recovery of margin revenues.

Furthermore, Rider VBA meets the criteria for a lawful rider in Illinois. Rider VBA would have two primary functions. First, Rider VBA would increase rates to account for margin revenues which the Utilities would be unable to collect in a given month due to changes in customer usage. Second, Rider VBA would lower rates to account for overrecovery of margin revenues by the Utilities in a given month due to customer usage changes. Those rate increases and decreases would occur under Rider VBA by operation of a mathematical formula that would be applied to the margin revenues which will have already been fixed and approved by the Commission in this proceeding. Thus, Rider VBA would involve no more than periodic adjustments to a rate that is fixed and approved by the Commission and such adjustments are determined by application of a mathematical formula. This type of rider formulation is the type of mechanism that the Court endorsed in *City of Chicago I*, *i.e.*, a rate schedule that contains "provisions which affect the dollars and cents cost of the product sold." *City of Chicago I*, 13 Ill.2d at 611.

The *City of Chicago I* Court held that an automatic rate adjustment clause does not change the fixed nature of rate approval by the Commission:

> [An adjustment] clause is nothing more or less than a fixed rule under which future rates to be charged the public are determined. It is simply an addition of a mathematical formula to the filed schedules of the Company under which the rates and charges fluctuate as the wholesale cost of gas to the Company fluctuates. Hence, the resulting rates under the escalator clause are as firmly fixed as if they were stated in terms of money.

Thus, where an adjustment mechanism is a rate schedule approved by the Commission which contains a mathematical formula for making future changes in the rate schedule, it is not unlawful under the PUA. Therefore, the adjustment contemplated under Rider VBA is precisely the type of adjustment mechanism contemplated in *City of Chicago I*. Rider VBA contains a mathematical formula that will result in monthly changes to the fixed margin revenue levels which this Commission has approved for the Utilities.

Approval of a decoupling mechanism, such as Rider VBA is well within an authority under the PUA. As discussed above, the Illinois Supreme Court has confirmed that we have broad latitude in setting utility rates, including making appropriate pragmatic adjustments. *See, City of Chicago I*, 13 Ill. 21 at 618, citing *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 602, 64 S. Ct. 281, 287, 88 L.Ed. 333, 344; *FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575, 586, 62 S. Ct. 736, 86 L.Ed. 1037, 1050. The broad latitude to employ pragmatic rate adjustments enables us to exercise our judgment to approve novel ratemaking techniques, including decoupling mechanisms. Indeed, permitting the adjustment of utility charges to reflect changes in the revenue collections to whic the utility is properly entitled are precisely the type of pragmatic adjustments contemplated under the PUA. .

Moreover, the decision making circumstances that gave rise to City *I* are strikingly similar to those that exist in respect of Rider VBA. City of Chicago *I* involved in consideration of whether to adopt a rider to permit automatic adjustment of purchased gas charges proposed for the first time in Illinois in a Peoples Gas case against the backdrop of such riders having been adopted in numerous other jurisdictions. Here Rider VBA is request by Peoples Gas and North Shore Gas for approval of a new rider permit the automatic adjustment of margin revenue recovery for this time in Illinois though the practice is followed in a number of other jurisdictions.

The rider approach was proposed in *City Chicago I*, to reflect the changed business conditions of escalating commodity gas costs relative to other utility expenses recovered in rates. In the case of Rider VBA, business conditions of fluctuating customer usage and the inability to fully recover authorized margin revenues, have necessitated Peoples Gas and North Shore Gas proposing a decoupling mechanism to address the new business challenges. The Utilities have demonstrated by means of record evidence that the business challenges are substantial.

While we are not required to consider the ratemaking practices employed in other jurisdictions, the fact that decoupling is in increasingly widespread use across the nation bears on our decision to approve Rider VBA. We are also persuaded of the reasonableness of Rider VBA because the rider involvesits recovery of margin revenues that we have already established in this case. Rider VBA simply reallocates these approved revenues from time to time.

There are imortant policy considerations that bear upon our decision to approve Rider VBA. The Utilities' embrace of conservation and the implementation of significant energy efficiency programs are compelling developments that should be balanced with appropriate adjustments to the ratemaking framework. Energy efficiency is an underutilized resource. All market participants, including the Utilities need to be part of a concerted effort to change the status quo. And, in the process, the current regulatory structure may also have to be re-examined and better tuned to accept new realities and objectives.~~ As such, we do not discount the decoupling mechanism altogether. It would be unwise and foolhardy to do so in this proceeding. It may well prove that a mechanism of this type and infused with properly structured safeguards may ultimately fulfill regulatory objectives in better way. But, at this time and in these premises, Rider VBA is not that proposal.~~ Rider VBA and the adoption of energy efficiency initiatives for the Utilities' systems are important steps in the reevaluation of the regulatory environment in view of changing realties.

~~In time, the Commission will need to see a full, reasoned and studied analysis both as to the benefits and the potential for harm that accompany a decoupling mechanism such as Rider VBA. We will further need to have all of the parties better understand the mechanism and to debate freely the various aspects that might have make such a mechanism viable. Ultimately, what the Commission seeks, is a more consensus oriented proposal.~~

~~In our view too, the better way is for the General Assembly to provide us with direct authority for examination of these and other mechanisms. In light of the State's rising concern for energy efficiency and conservation measures, we believe it equally important that this Commission be given the express authority to consider new regulatory mechanisms that correspond to these initiatives.~~

~~If we are not prepared to approve Rider VBA today, the Commission is still better informed for the future.~~

We are aware that a number of jurisdictions have approved decoupling with certain conditions designed to protect ratepayers and to determine the longer term viability of such rate mechanisms. In recognition of this caution and in acknowledgement of the arguments raised by Staff, GCI and the AG in opposition to Rider VBA, we direct that Rider VBA be implemented for a four year period. During such four year period, the Utilities must annually conduct workshops with the participation of all interested parties to ascertain whether issues arise which require a reevaluation of the implementation of Rider VBA. In order to continue the implementation of Rider VBA beyond such four year period, the Utilities must file a new rate case which incorporates any revisions to Rider VBA that may have become apparent in the workshops we direct to be held. This will ensure that we have an opportunity to monitor and take appropriate steps to address the long term impact of decoupling as a viable mechanism in Illinois. In this manner, ratepayers and other interested parties, as well as the Commission Staff, would have the opportunity to evaluate the operation and effectiveness of decoupling as it is actually employed by the Utilities in today's environment and not as an abstraction. Such an approach would be far superior to, for example, study and evaluation of the particulars and experience of decoupling in other states, whose utilities may not operate in the same fashion as Peoples Gas and North Shore Gas or where different business challenges might pertain.

There are no test year prescriptions that are violated by Rider VBA because this case arises out of a general rate case proceeding where the costs and expenses have been submitted under the Commission's test year rules. The base rates that are approved in this case and which are the basis for the margin revenues to be recovered under Rider VBA have been evaluated in accordance with the appropriate test year prescriptions.

There is also no absolute requirement that rider costs be unexpected, volatile or fluctuating. As we discuss herein , the more recent cases make it clear that there is no legal limitation on the use of riders to those instances when costs are unexpected, volatile or fluctuating.[19/] *See*, herein *City of Chicago II*, 281 Ill. App 3d at 617, rider costs need not necessarily involve costs that are unexpected, volatile or fluctuating. It is simply enough that costs suitable for rider treatment do not violate the prescriptions against single issue ratemaking or the test year rules. As with the municipal franchising fees at issue in *City of Chicago II*, the margin revenues which are recovered under Rider VBA do not involve single issue ratemaking because they do not have any impact whatsoever on the Utility's overall revenue requirement or rate of return. *See City of Chicago II*, 281 Ill. App 3d, 629. Margin revenues will have been determined as part of the overall revenue requirement in the instant proceeding and the adjustments that occur under Rider VBA will never change the Utilities approved revenue requirement.

[19/] Though it is not necessary to do so, we would observe that the margin revenue fluctuations and the varying customer usage patterns demonstrated by the Utilities exhibit unexpected and fluctuating behavior.

Finally, just as we needed no legislative authority to employ automatic gas charge recovery adjustment mechanisms, no authorization from the General Assembly is required to implement Rider VBA. There is nothing about the revenues that could be recovered under Rider VBA or otherwise in a decoupling mechanism which involves cost or revenue elements that are not the subject of routine, traditional Commission ratemaking. The PUA likewise permits the Commission to employ decoupling for the Utilities in the form of Rider VBA without any additional guidance from the General Assembly. For the foregoing reasons we approve Rider VBA today.

2. Rider WNA

Exception No. 18

The Proposed Order on page 140 should be modified as follows, or, in the alternative, as provided in Alternative A:

f. Commission Analysis and Conclusion

The Commission has not found it ~~reasonable or appropriate to approve proposed Rider VBA. And, we here conclude in the same way with respect to the alternative proposal of Rider WNA. To be sure, Staff and the Intervenors appear somewhat less critical of Rider WNA. Nevertheless, this mechanism needed their active support. In something this new, we need to know not only what is wrong, but what can be corrected or modified to make the mechanism work properly for both the Utilities and the ratepayers. There is no evidence of this type on record. .~~necessary to approve proposed Rider WNA, because we approve Rider VBA. The Utilities have presented alternatives which comprise a range of reasonable and appropriate measures for addressing the margin revenue challenges. Rider VBA would provide the Utilities the fuller means by which margin revenue recovery capability can be achieved. Since Rider WNA has been presented as an alternative to Rider VBA, our decision to approve Rider VBA renders it unnecessary to address Rider WNA.

~~We recognize that variations from normal weather will have an effect on the revenues arising from rates established in this proceeding. Indeed, in another part of this Order dealing with Gas in Storage we observed that weather played a critical role. We recognize too, that when a utility sells less gas, it recovers a smaller portion of its fixed costs. There are, however, some changes being brought about in this proceeding and it is too soon to tell if these will not lessen the Utilities' climate challenges. We recognize too, that mechanisms such as the Utilities' proposed Rider WNA have some merit and have gained acceptance in other jurisdictions. But, where this proposal has not been developed in a way to foster support and understanding among all of the parties,~~

~~it essentially leaves the Commission unable to meaningfully assess all of the benefits and pitfalls of taking such a novel step. At this time, and in these premises, the Commission rejects Rider WNA.~~

Alternative A

While we are cognizant of the business challenges and usage patterns demonstrated by the Utilities in this proceeding and the need to respond to those conditions in the ratemaking framework, we are, however, reluctant to approve decoupling for the Utilities at this time. We desire to further evaluate the regulatory environment in Illinois and the interplay between the rate structures that we have approved and the changing gas usage patterns of ratepayers and the impact of that phenomenon on Utilities.

We nevertheless feel obligated to address in some manner the demonstrated gas usage variations that the Utilities have established. We recognize that Rider VBA would offer the broader response to those conditions but we believe that a more measured and less broad approach is appropriate at this time. We believe that Rider WNA will provide the Utilities with an additional measure of revenue stability

We recognize that variations from normal weather will have an effect on the revenues arising from rates established in this proceeding. Indeed, in another part of this Order dealing with Gas in Storage we observed that weather played a critical role. We recognize too, that when a utility sells less gas, it recovers a smaller portion of its fixed costs. ~~There are, however, some changes being brought about in this proceeding and it is too soon to tell if these will not lessen the Utilities' climate challenges. We recognize too, that mechanisms such as the Utilities' proposed Rider WNA have some merit and have gained acceptance in other jurisdictions. But, where this proposal has not been developed in a way to foster support and understanding among all of the parties, it essentially leaves the Commission unable to meaningfully assess all of the benefits and pitfalls of taking such a novel step. At this time, and in these premises, the Commission rejects Rider WNA~~As the record establishes, weather normalization adjustments are quite common and have been widely implemented across the country. The record contains no evidence that weather normalization adjustments have been the subject of policy concerns which limit their broader adoption. Rider WNA would not constitute retroactive ratemaking or single issue ratemaking. As was discussed in respect of Rider VBA, a rider which addresses margin revenues has not been found unlawful in Illinois. Furthermore, the margin revenues which would be the subject of Rider WNA would be established in these rate proceedings. Any adjustments that result by operation of Rider WNA would occur within the Commission established margin revenue determination and Rider WNA would operate simply as a mathematical formula which would generate adjustments to the Commission determined margin revenue requirement. This is the type of mechanism which the Court has endorsed in their articulation of the Commission's broad discretion to adopt riders and to make pragmatic rate adjustments. *See, City of Chicago*, 13 Ill.2d at 613-614. In view of the mathematical formula being applied to the Commission established rate, there can be no retroactive ratemaking effect.

Rider WNA likewise does not constitute single issue ratemaking. Rider WNA addresses margin revenues and not costs. Hence, there is no more dynamic involved which would analyze the impact of any set of costs and expenses on the revenue requirement or rate of return. Rider WNA simply adjusts a Commission determined rate component, margin revenues, by determining whether weather has negatively or positively affected the Utilities' ability to fully recover margin revenues in any given month and adjusts the Commission determined rate accordingly. When weather is colder, ratepayers will receive a reduction in the rate which would normally apply and if the weather is warmer than normal, ratepayers would pay relatively more than would otherwise apply. This symmetrical operation of Rider WNA ensures that Rider WNA does not enable the Utilities to exceed their Commission Approved revenue requirement. We therefore approve Rider WNA as the most reasonable means of addressing the demonstrated challenges at this time.

C. Rider ICR

Exception No. 19

The Proposed Order on pages 144-149 should be modified as follows:

Commission Conclusion

The issues concerning Rider ICR are the same posed by the other proposed riders – does the Commission have the discretionary authority to authorize rider recovery and should we exercise that authority in this instance?

Many of the governing precedents and principles delineating our discretionary authority were previously discussed in this Order. Reviewing the decisions most relevant to this rider, ~~in City of Chicago v. Commerce Commission, 13 Ill.2d 607, 150 N.E.2d 776 (1958) ("City I") the Illinois Supreme Court held that it was not an abuse of our discretion to permit continuous recovery of gas costs through an automatic adjustment mechanism. The court cited the "pragmatic" ratemaking power vested in the Commission by the legislature. 13 Ill.2d 618. However, the court also specifically noted that our then existing practice had been to "allow rate increases based on an anticipated increase in the cost of natural gas to go into effect without suspension." Id. Accordingly, the court viewed the dispositive issue as "a question of preferable techniques in utility regulation." Id. In the present dockets, we note that there is no existing practice of incorporating the depreciation and carrying costs associated with capital investments into base rates without a rate review~~

~~proceeding. Consequently, the present case does not involve a "preferable technique" for achieving a familiar result.~~City of Chicago I is the starting point for discussion. As discussed under Rider ICR, *City of Chicago I* did not place any specific limitations on the Commission's power to employ riders or make pragmatic adjustments to utility rates.

In *City of* Chicago *I*, the Court was quite clear in affirming that the Commission possesses broad discretion under the PUA to employ automatic rate adjustment mechanisms as the Commission deems appropriate. The Commission's broad discretion is not limited simply to whether to employ riders but consists also of the power to make any necessary pragmatic adjustments to utility rates. *See, City of Chicago I*, 13 Ill.2d at 618.

~~In A. Finkl v. Illinois Commerce Commission, 250 Ill.App.3d 317, 620 N.E.2d 1141 (1993), the Illinois Court of Appeals overturned our ruling that Commonwealth Edison could recover demand side management expenses through a rider, on the grounds that we had violated the prohibition against single-issue ratemaking and our test year rule. The Commission proceeding under review was not a rate case and, ironically, we had unsuccessfully argued that the single-issue ratemaking prohibition applied only in rate cases. In any event, the court disapproved of "isolat[ing] one operating expense for full recovery without considering changes in other expenses or increase sales and income obviate the need for increased charges to consumers." 250 Ill.App.3d at 326. The record in the instant cases does show (indeed, it is much of the rationale for Rider ICR) that main replacement tends to reduce O & M costs, and accelerated replacement will produce inflation savings, as well as lower street repair costs. These savings will not be balanced against the costs passing through the rider until a rate proceeding is conducted.~~

~~Finkl also identifies conditions that would make rider treatment appropriate (assuming the rule against single-issue ratemaking is not affronted): "Riders are useful in alleviating the burden imposed upon a utility in meeting~~ *Finkl* involved the determination as to whether the expenses of Edison's demand side management program were unexpected, volatile or fluctuating. Peoples Gas has demonstrated that because the particular projects that might be eligible for Rider ICR recovery are highly dependent upon the decisions and actions of third parties (*i.e.*, the City of Chicago and project developers), the Rider ICR expenses are unquestionably unpredictable and uncertain. The level of expenditure for any particular CI/DI main replacement cannot be known until the project is identified and evaluated, which cannot occur until an opportunity presents itself. Such uncertainty and unpredictability is the essence of the concepts of unexpected and fluctuating, in much the same as coal tar clean up costs were. The latter were incurred on a project by project basis and the level of expenses could not be predicted with any certainty. Thus, Rider ICR expenses comport with the criteria that rider costs be unexpected, volatile or fluctuating~~ expenses." *Id*. at 327 (emphasis in original). While the parties here have robustly debated the~~

~~applicability of the individual italicized terms in the foregoing quotation to the evidentiary record in these dockets, the meaning of the full sentence has perhaps been under-scrutinized. The court is addressing a "burden" on the utility imposed by costs it cannot avoid or control. The gas costs discussed in City of Chicago were (and still are) unavoidable, given the gas utilities' statutory and contractual obligations. So, too, were the regulatory requirements in Finkl (although they were not beyond the utility's control, in the court's view). In contrast, the main replacement costs in the instant case will arise at whatever pace the Utilities choose. And although those costs will likely fluctuate, in the sense that each project would presumably have its own price-tag, the Utilities can avoid fluctuation that is not to their liking, simply by postponing work. A central rationale for Rider ICR is to enable the Utilities to seize opportunities for savings, not to alleviate the burden of unavoidable cost gyrations. In CILCO v Illinois Commerce Commission, 255 Ill.App.3d 876, 626 N.E.2d 728 (1993), the Court of Appeals upheld our decision, in an industry-wide proceeding, to allow rider recovery for legally required coal-tar cleanup costs. The court emphasized our finding that "these costs will vary widely from year to year depending on the type of remediation activities" and concluded that, unlike the costs in Finkl, they were "the type of unexpected, volatile and fluctuating costs which are more efficiently addressed through a rider." 255 Ill.App.3d at 885.~~ . Rider ICR does not contravene any aspect of *Finkl*.

Parties have expressed concern about whether Rider ICR violates the proscription against single issue ratemaking. This concern, however, is ameliorated by reference to the record in this proceeding. There is no question that the contemplated main replacements will tend to generate savings. Peoples Gas has submitted evidence that establishes specific O & M savings will be achieved by CI/DI main replacement. Among these are potential leak repair savings of $3,000 per mile for annual savings of $180,000 - $300,000 per year, Schott Tr. at 1551:8-17, and deferred tax savings.

In addition, it should be noted that Peoples Gas has significantly modified its original Rider ICR proposal to incorporate features that considerably limit its scope and that lend substantial protections to ratepayers. Many of the modifications to the original Rider ICR were proposed by the Commission Staff. These modifications include: (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. The Commission Staff also proposed a framework for Rider ICR that is modeled on Part 656 of the Commission's Regulation (Part 656). While Peoples Gas did not find the entire Part 656 framework acceptable, it has adopted several of the Part 656 features into the modified Rider ICR. These modifications render the rider more reasonable and achieves a greater balance of customer and utility interests, further addressing any issues that suggest Rider ICR does not factor in all appropriate interests.

Thus, to address single issue ratemaking, we will condition approval of Rider ICR upon Peoples Gas including as an offset against Rider ICR charges amounts reasonably attributable to leak repair savings and reductions in deferred taxes occasioned by CI/DI main replacement. Peoples Gas will be required to calculate these savings based on the past year's activity in the annual reconciliation filing with the inclusion of the appropriate credits. This adjustment, along with the modifications to which Peoples Gas has already agreed should more than satisfy any concerns that Rider ICR constitutes single issue ratemaking.

It is the Commission's view that we possess the authority to authorize rider recovery of Rider ICR costs, as discussed in more detail previously, because the costs are of such a nature that neither their timing nor their level can be predicted and the incurrence of the costs is dependent upon circumstances and parties that are not within the control of Peoples Gas. Thus, Rider ICR costs are indeed either "unexpected, volatile or fluctuating", thereby qualifying for rider treatment and the costs in Rider ICR are suitable for the exercise of Commission discretion to make practical ratemaking adjustments under settled Illinois law.

Nevertheless, City *of Chicago II* made it clear that under Illinois law, nothing "limits the use of a rider only to those cases where expenses are unexpected, volatile or fluctuating," *City of Chicago II*, 281 Ill. App. 2d at 628. It cannot be overlooked that the CI/DI main replacement which Rider ICR is designed to address is a circumstance that is unique to the City of Chicago, given the age and density of the City. The ability to substantially reduce the estimated 40 years time frame for the replacement of Chicago CI/DI main presents a unique opportunity for the Peoples Gas system. Peoples Gas submitted evidence which vividly demonstrates the extent of CI/DI main present in Chicago, thereby demonstrating the pressing need to modernize those facilities. *See*, Schott Sur., NS-PGL Ex. JFS-3.2. Indeed, there is no question that there is not another municipality in Illinois with the density reflected in NS-PGL Ex. JFS-3.2, and whose gas utility is the age of the Chicago gas infrastructure system. It simply cannot be seriously argued that the situation in Chicago is not unique in Illinois.

~~CILCO was reviewed by the Illinois Supreme Court as~~ *Citizens Utility Board v.* ~~Illinois Commerce Commission~~*ICC*, 166 Ill.2d 111, 651 N.E. 2d 9089 (1995)~~, which held that "approval of a rider as the preferred mechanism for recovery of coal-tar cleanup costs is within the Commission's authority and not against the manifest weight of the evidence." 166 Ill.2d at 140. The court noted that the generic proceeding before it "does not attempt to evaluate or adjust all aspects of the utilities' base rates, and thus the test-year filing is not a prerequisite."~~ ~~*Id*.~~ ("*Citizens Utility Board*") held that the Commission has the discretion to approve direct recovery of unique costs through a rider when circumstances warrant. The compelling circumstances attending the CI/DI main replacement in Chicago certainly render the costs to be recovered under Rider ICR unique. Rider ICR costs therefore are eligible for rider recovery, irrespective of whether they are unexpected, volatile or fluctuating under the reasoning espoused by *City of Chicago II* and *Citizens Utility Board*.

~~In City of Chicago v. Commerce Commission, 281 Ill.App.3d 617, 666 N.E.2d 1212 (1996) ("City II"), the Illinois Court of Appeals affirmed our Order authorizing Commonwealth Edison to localize its recovery of municipal franchise fees by collecting, via rider, each municipality's fees solely from customers in that municipality. Such fees had previously been recovered in the aggregate through base rates paid by all customers throughout Commonwealth Edison's service territory. Although municipal franchise fees are typically predictable and stable, the court stated that nothing in prior precedent[26] "limits the use of a rider only to those cases where expenses are unexpected, volatile or fluctuating." 281 Ill.App.3d at 628. The court noted, however, that "[r]iders are closely scrutinized because of the danger of single-issue ratemaking," *id*., which is "prohibited because it considers changes in isolation, thereby ignoring potentially offsetting considerations and risking understatement or overstatement of the overall revenue requirement." *Id*. at 627. The court concluded that the franchise fee riders under review did not constitute single-issue ratemaking because "they did not have any impact whatsoever on Edison's overall revenue requirement" and were "'without direct impact on the utility's rate of return.'" *Id*. at 629.~~

~~[26/]The court specifically cited Finkl, *supra*, and City I (which it erroneously identified in that context as "Citizens Utility Board").~~

~~The foregoing cases plainly confirm that the Commission has discretionary latitude to authorize rider recovery, but they also confirm that the prohibition against single-issue ratemaking, as well as the test year rule, remain in place. Even in decisions upholding rider treatment - Citizens Utility Board, City II and CILCO – the courts acknowledge the single-issue ratemaking prohibition. That is, the courts have consistently held that when a utility's actions may affect its overall revenue needs in disparate ways, all impacts of such actions – both expenses and savings – must be considered and balanced in ratemaking[27].~~

~~[27/]This principle has been reiterated in proceedings not involving riders as well. One pertinent example: "it would be improper to consider changes to components of the revenue requirement in isolation. Oftentimes a change in one item of the revenue formula is offset by a corresponding change in another component of the formula. For example, *an increase in depreciation expense* attributable to a new plant may be offset by a decrease in the cost in the cost of labor due to increased productivity, or by increased demand for electricity." BPI v. Illinois Commerce Commission, 146 Ill.2d 175, 244, 585 N.E.2d 1032 (1991) (emphasis added).~~

~~In the present cases, there is no question that the contemplated main replacements will tend to generate savings. The Utilities emphasize this. In our judgment, approval of Rider ICR, which will ignore those asserted savings while passing costs through to ratepayers, contravenes the prohibition on single-issue~~

~~ratemaking. None of the precedents above suggests a contrary conclusion. None involved (much less approved) rider treatment for capital investments or associated depreciation and capital costs and none reviewed a base ratemaking proceeding.~~

~~There is language in Citizens Utility Board that the Commission could seize upon in an attempt to elevate our discretion above the single-issue ratemaking prohibition. "The rule does not circumscribe the Commission's ability to approve direct recovery of unique costs through a rider when circumstances warrant such treatment." 106 Ill.2d at 138. To do so, however, would be to distort the court's meaning. In the same paragraph, the court expressly stated that "[i]n the present case we are not faced with the Commission's treating a single-expense item *within the context of a general rate case*." *Id*. at 137-38 (emphasis added). The court continued: "[t]he prohibition against single-issue ratemaking requires that, in a general base rate proceeding, the Commission must examine all elements of the revenue requirement formula to determine the interaction and overall impact any change *will* have on the utility's revenue requirement, including its return on investment." *Id*. at 138 (emphasis in original). Thus, the court's mention of rider recovery "unique" costs (in the sentence immediately following) describes our authority *outside of* base rate proceedings, not within them (where the rule against single-issue ratemaking cannot be disregarded).~~

~~Moreover, when the General Assembly has wanted to accord non-traditional ratemaking treatment to costs associated with capital spending, it has done so explicitly.~~

~~In Section 9-220.2 of the Act (discussed by the parties here because it is the statutory source for Part 656), surcharges for water and sewer utility infrastructure were expressly authorized, "independent of any other matter's related to the utility's revenue requirement." In Section 9-214 of the Act[28], the General Assembly determined that a portion of the costs related to capital investments[29] could be placed in an electric utility's rate base up to a year before the associated assets were used to serve customers. These statutory mechanisms accomplish what PGL seeks with Rider ICR – quicker recovery of costs arising from capital projects[30]. The fact that the General Assembly enacted these provisions suggests that the Commission does not have the discretionary power to grant early relief for capital expenses.~~

~~28/ 220 ILCS 5/9-214.~~

~~29 These are known as "CWIP" or construction work in progress.~~

~~30 "[I]t is simply infeasible to expect [PGL] to pursue accelerating main replacement without the financial assurance it needs between rate cases." PGL-NS Init. Br. at 110 (footnote omitted).~~

~~Even if we were inclined to assert that our discretionary power trumped the single-issue ratemaking prohibition, or that the prohibition did not apply to Rider ICR, all parties agree here that the rider would still have to meet the~~

~~conditions for rider treatment. That is, the pertinent expenses, arising from acceleration of the Main Replacement Program, would have to be unexpected, volatile or fluctuating.~~

~~Main replacement is not itself unexpected. It has been ongoing since 1981 and will continue without Rider ICR until approximately 2050. There is no evidence that the principal costs involved in main replacement (such as labor, materials, permits or the cost of money) will rise abruptly or precipitously. There is only the familiar nostrum that costs incurred sooner are ultimately less than the same costs incurred later[31]. What is unexpected - or, more accurately, unpredictable - according to PGL are future opportunities for cost-shaving and cost-sharing when other entities perform infrastructure work in Chicago. Such opportunities could arise more frequently than is customary, PGL contends, if, for example, the City's bid for the 2016 Summer Olympics is successful or the proposed Crosstown Expressway is constructed. However, if such extraordinary events are scheduled (and if the opportunities they present do implicate a substantial portion of PGL's unimproved main), PGL will know well in advance, with ample opportunity to request base rate adjustment. As for more mundane municipal projects and repairs, there is simply no evidence that the near future will differ from the recent past.~~

~~[31]/This does not necessarily benefit ratepayers, who forego the opportunity value of their money when they part with it sooner.~~

~~Similarly, there is no evidence that either the occurrence or cost of main replacement actually is (or actually will be) volatile or fluctuating. Again, the variability PGL emphasizes is not in the cost of main replacement. Indeed, PGL can simply avoid any new main replacement opportunity that arises (absent emergency) if the price or some other factor is unattractive. Futher, PGL is not committing to any specific acceleration rate in its main improvement program and CI/DI replacement will remain at its discretion. Tr. 1617-18 (Schott). As Staff states, "[t]he only unpredictability asserted is not knowing on a long term basis what street or other infrastructure projects the City of Chicago may be undertaking." Staff Rep. Br. at 74. In our view, that does not amount to the volatility or fluctuation that would justify rider recovery.~~

~~This is particularly clear when the capital expenditures that would be recovered with Rider ICR are compared to the gas costs that flow through the PGA. Two factors are important – price and avoidability. The parties and the Commission all recognize that gas prices are volatile, with changes that are both too fast and too significant to capture in base rates. Main replacement (or, at the least, main replacement in excess of past experience) does not have these characteristics.~~

~~Regarding avoidability, PGL'S need to purchase gas (or release it from storage and purchase replenishment) is continuous, because of statutory and contractual obligations. Gas costs are thus like the other unavoidable expenses granted rider treatment in the cases discussed above: coal-tar cleanup costs~~

~~(~~Citizens Utility Board~~); and municipal franchise fees~~~~[32]~~ ~~(~~City II~~). In contrast, the additional savings opportunities that ostensibly justify the ICR are speculative in every meaningful respect and can be avoided if circumstances become unfavorable. It is not simply that the Summer Olympics may go elsewhere. There is no assurance - there is even no clear likelihood - that standard municipal improvements and private development projects will unfold at a rate or scale that exceed the historic levels reflected in base rates. There is similarly no clear likelihood that projects that do arise will implicate significant spans of CI/DI mains that PGL has prioritized for replacement through its MRI analysis (which are also the mains more likely to experience the cost-producing leaks PGL hopes to avert). In short, there is no unpredictable or uncontrollable cost burden for which PGL needs rider relief.~~

~~[32/]Which also warranted rider treatment because a different charge was required for each municipality.~~

~~Importantly, safety and reliability are not part of the supporting rationale for Rider ICR. PGL expressly states that it:~~

Peoples Gas should be lauded for its efforts to improve the distribution system and the infrastructure in the City of Chicago. Aside from the sheer magnitude of the replacement of CI/DI mains in Chicago, the Commission takes cognizance of the City of Chicago itself's unqualified support of Rider ICR.

The City of Chicago described the acceleration of CI/DI main replacement as a "significant effort to bolster and improve this critical aspect of Chicago's infrastructure." City Init. Br. at 311. The City also acknowledged that Rider ICR will allow Peoples Gas to coordinate with the City and others as they pursue development projects in Chicago without the potential uncertainty that accompanies having to wait until the next rate case to recover the cost of taking advantage of such opportunities. *Id.* The City is the most strategic and pivotal participant, along with Peoples Gas, in the implementation of the accelerated main replacement program. Hence, the City's recognition of the importance of Peoples Gas' effort to modernize the utility infrastructure in the City is of major significance. As a major customer of Peoples Gas, the City's support is even more compelling.

The City's active support of Rider ICR is a meaningful factor in prompting us to view Rider ICR favorably, not only because it meets the legal criteria for a rider, but also because the CI/DI replacement program will achieve a laudable public policy goal that is important for the longer term maintenance of reliable and safe natural gas service in Chicago.

~~…has never argued that its system is unsafe or unreliable or that the purpose of the accelerated program is to enhance safety or reliability.~~ It bears repeating, the purpose of accelerating CI/DI main replacement is to considerably shorten the time frame by which the entire project could be completed and to substantially improve the gas utility infrastructure in the City of Chicago. There are no current issues involving safety or reliability and the replacement of CI/DI mains, either on an accelerated basis or under the existing schedule has no implications for safety or reliability. Nevertheless, major improvements to the infrastructure of an important area such as the City of Chicago meaningful bearing on our decision to approve Rider ICR. We therefore direct that Rider ICR be implemented in accordance with the foregoing discussion.

~~PGL-NS Rep. Br. at 110. Consequently, there are no exigent safety or reliability concerns that would either compel PGL to bear significant costs at an unsustainable pace or compel the Commission to test the limits of our power to provide financial relief via rider.~~

~~For all of the reasons discussed above, the Commission will not approve Rider ICR. The rider would recover expenses during an indefinite period before attendant savings are reflected in rates. We conclude that this is beyond our authority and, even if it is not, we decline to use our discretion for this purpose. To be clear, this conclusion is not intended to prejudice any base rate treatment PGL may subsequently seek for CI/DI main replacement expenditures. Indeed, the Commission commends PGL's improvement of its distribution system.~~

Since we ~~reject~~approve Rider ICR, there is no reason to address Staff's alternative Rider QIP and we will not do so.

E. Deferred Accounting Alternative to Certain Rider Requests

Exception No. 20

Page 176 of the Proposed Order should be modified as follows, in the event that the Commission does not approve Rider VBA or Rider WNA as provided for in the Utilities' Exception Nos. 17 and 18:

> In the event the Commission rejects one or more of Riders VBA, UBA or EEP, the Utilities propose, as an alternative, to track the underlying revenues and costs in deferral accounts, for later refund or adjustment to base rates as determined on an annual basis. PGL-NS Ex. VG-2.0 at 50-51. The Utilities assert that this would not violate test year principles but would, instead, allow them to go ahead with these expenditures. Given that the Commission has approved Rider EEP, ~~but rejected Rider UBA,~~ the Utilities' fall-back proposal would not apply to that ~~the latter~~ rider.
>
> With respect to Rider UBA, the Utilities' argue that "normalization of uncollectible expenses is hardly unprecedented." PGL-NS Rep. Br. at

127. The Commission does not agree that the future recovery requested here is a matter of "normalization." Nor is this a matter of completing a previously approved amortization. Uncollectibles are operating expenses and, as Staff states, "recovery of operating expenses outside of the test year violates test year principles" articulated in BPI II. Staff Init. Br. at 223. Furthermore, even if the Commission could approve the requested deferred accounting of uncollectibles, we would not exercise our discretion to do so. We believe that a reasonable quantification of the Utilities' gas-related uncollectibles has been incorporated in the rates approved by this Order. The Commission does not perceive that the Utilities' actual uncollectibles will differ appreciably from that quantification.

We do not consider our rejection of Riders VBA and WNA to require deferred accounting, but we nonetheless find that, on balance, the revenues underlying what would have been Rider VBA are appropriate for deferral for future recovery as proposed by the Companies. The Commission has determined that such deferral would not constitute retroactive ratemaking in violation of *BPI II* because the regular true-up of revenues will be self-effectuating upon the Commission's issuance of this order, and *BPI II* is distinguishable on that basis. That is, this will not be a case where the Commission later determines that rates were too low, nor excessive, but instead rates will simply be trued-up to provide the Companies with the precise revenue requirement (no more and no less) approved here. Since these deferrals relate to revenues the Companies would have received but for certain environmental and economic circumstances beyond their control, such true-ups will only ensure that assumptions which formed the basis of rates established in this proceeding will, in fact, "come true," and the Commission finds this to be a fair and appropriate outcome.

While deferrals are not routinely permitted, the Commission finds under the particular circumstances of this proceeding that it is proper to exercise its discretionary authority which, as recognized by the courts since *BPI II*, contemplates approval of mechanisms such as the tracking accounts proposed here for deferred amounts that will be used to help arrive at a more normal or representative test year allowance as an alternative to unrepresentative test year projections. The Commission therefore finds that the tracking of revenues and costs underlying the proposed Rider VBA in a deferral account, for later refund or recovery on an annual true-up basis, is reasonable, and approves such mechanism as proposed by the Companies.

VIII. COST OF SERVICE

B. Embedded Cost of Service Study

2. Contested Issues

a) Coincident Peak Versus Average and Peak Allocation Methods

Exception No. 21

The third full paragraph on page 179 of the Proposed Order in the description of the Utilities' position, should be revised as follows:

(1) Utilities

* * * *

> The Utilities believe that the CP method is the soundest approach to allocation of system costs. The CP method most closely matches the principle that cost ~~causation~~ responsibility should follow cost ~~responsibility~~causation. The distribution system was built to serve the peak demands of the system. Thus, a customer's peak demand on the system corresponds to the costs that have been incurred to install that capacity. Since the customer's demand on the system prompted the installation of facilities to meet that demand, it stands to reason that customers should be allocated costs in a manner that recognizes their call on the system.

The Commission Analysis and Conclusion on pages 185-186 of the Proposed Order should be revised as follows:

> (5) Commission Analysis and Conclusion
>
> The issue is whether common system distribution costs should be allocated on the basis of the Coincident Peak ("CP") method or the Average~~s~~ and Peak ("A&P") methodology.
>
> The Utilities preferred methodology is CP because, in their view, it most appropriately ~~takes~~ accounts for ~~of~~ the specific systems that are sized to meet peak demands and, in doing so, adheres to the principle of allocating costs on a causal basis. Staff, the AG, and City-CUB, all maintain that an Average and Peak method is more balanced because it weights 75% of common system distribution costs according to coincident peak and 25% according to average deliveries.

I~~f~~n every situation where it is reasonable to do so, the Commission will consider its own past practice in resolving an issue. ~~Staff informs that over the past decade, the Commission has consistently found the A&P allocation of distribution system costs to be preferable to a CP allocation. There is nothing to persuade us differently in this Instance. In other words, the Utilities have not overcome the Commission established and long-standing tradition of A&P methodology for allocating distribution costs.~~For this issue, the Commission's past practice is not clearly settled. As Staff argues, the Commission has used the A&P allocator for gas utilities' distribution system investment in several recent cases. However, the Commission has also used the CP and average and excess allocator in gas utility cases, and it has consistently used a non-coincident peak allocator (which resembles CP in many respects) for electric utilities' distribution system investments. The Commission finds the Utilities' evidence in support of the CP allocator persuasive and adopts that method. The evidence in this proceeding shows that the CP allocator best reflects cost causation for the distribution system which is, indisputably, designed to meet the system peak, and is, therefore, the appropriate method for allocating these costs.

b) Classification of Uncollectible Account Expenses Account No. 904

Exception No. 22

The Commission Analysis and Conclusion on page 187 of the Proposed Order should be revised as follows:

(3) Commission Analysis and Conclusion

The issue here is whether Account No. 904 should be classified as customer costs as the Utilities have proposed.

Having studied the positions at hand, the Commission accepts ~~Staff~~Utilities witness ~~Luth's~~ Amen's proposal that Account No. 904 expenses should be classified as ~~a combination of~~ customer costs~~, demand costs, and commodity costs including gas costs. The Commission further accepts Mr. Luth's proposal to 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 various categories of costs.~~ As Mr. Amen explained, the key fact is that the uncollectible expense arises from customers' unpaid bills and not from the specific components of those bills. The analysis provided by ~~Staff~~ Mr. Amen in this instance is clear, thorough and highly persuasive.

Therefore, the Commission approves, as reasonable and appropriate, ~~Staff's~~the Utilities' classification of expenses recorded in Account No. 904, Uncollectible Account Expenses.

d) Allocation of Distribution Plant Account No. 385

Exception No. 23

The Commission Analysis and Conclusion on page 198 of the Proposed Order should be revised as follows:

(5) Commission Analysis and Conclusion

The issue at hand is whether Account No. 385 costs should be directly assigned to individual customers for the purpose of determining customer-specific charges, as proposed by GCI but as opposed by Peoples Gas~~the Utilities~~.

We pay special attention here to the respective testimonies of the Utilities witness Amen and the GCI's witness Glahn. On the basis of our review, Mr. ~~Glahn's~~Amen's account and his reasoning are far more persuasive than anything we hear on ~~the Utilities'~~ GCI's side.

Account No. 385 represents industrial measuring and regulating station equipment expense. Mr. Glahn proposes that Account 385 costs should be directly charged as a facilities charge or metering surcharge to the individual customers generating those costs and for reasons that ~~the Utility~~Peoples Gas 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.

~~The Commission is far less impressed with the Utility's claim that the overall impact of the issue Mr. Glahn raises is extremely small, i.e., Account No. 385 represents less than 0.04% of Peoples Gas' customer related distribution plant. In our view, there is much more to the situation. Mr. Glahn's proposal rests on questions of fairness and equity with respect to the treatment of customers whose costs can be specifically identified to them.~~ The Commission believes Mr. Glahn's approach would be impractical and inappropriate. 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 Commission agrees that ~~Where, as here, the Commission sees that~~ the Utilities have the capability to identify the specific plant costs of meters, regulators and services with individual customers in all of its service classes; however, we believe this would create a multiplicity of charges, and an impractical rate approach~~,~~ ~~we consider it appropriate to rely on those attributes~~. To the extent practicable, a sound rate structure should include the practical attributes of simplicity, understandability, certainty and feasibility of application. It would not be reasonable to single out for direct assignment to customers one account with a fairly small amount of costs. Thus, the Commission approves Peoples Gas' proposal as fair, reasonable and appropriate.~~In the final analysis, the Commission finds GCI witness Glahn's proposal to be consistent with these objectives, fair in implementation, and it is approved.~~

IX. RATE DESIGN

B. General Rate Design

2. Gas Cost Related Uncollectible Expense

Exception No. 24

The description of the Utilities' position in Section 2(a) on pages 213-214 of the Proposed Order should be revised by adding the following new paragraphs on page 214 at the end of Section 2(a), immediately preceding subsection (b) describing the Staff's position:

a. Utilities

* * *

In their Brief on Exceptions, the Utilities argued that the AG's first point pertains to the amount of dollars to be allocated and is unrelated to the underlying rate design issue. The AG's second point is a criticism of the proposed bifurcation of S.C. No. 1 into a heating and non-heating service classification and is, likewise, unrelated to the underlying rate design issue. Similarly, the Utilities argued that the AG's fourth point about proper price signals would be more properly addressed in the larger context of the S.C. No. 1 rate design and not in connection with this design question for a specific cost.

The Utilities stated that the AG's third point, addressing the allocation of the uncollectible expense for S.C. No. 1H between the first and second block, ignores the fact that the Utilities' proposal for this item is consistent with its overall proposal for S.C. No. 1H. Specifically, the Utilities proposed that 67% of the expense be allocated to the front block, just as it proposed for the allocation of costs not recovered through the customer charge. Peoples Gas Ex. VG-1.0, p.14; North Shore Ex. VG-1.0, p. 12; *also see* North Shore/Peoples Gas Ex. 3.0 REV, p. 18. There are no alternative formulaic proposals for determining distribution charges once the Commission sets the revenue requirement and the customer charge component of the service classifications. According to the Utilities, only they proposed specific methods for easily and objectively determining distribution charges, whatever revenue requirement is approved. *See, e.g.*, North Shore/Peoples Gas Ex. VG-3.0 REV, pp. 5, 18, 19, 22.

The Commission Analysis and Conclusion on page 217 of the Proposed Order should be revised as follows:

d) Commission Analysis and Conclusion

The Utilities and Staff address the issue of the appropriate recovery of gas cost related uncollectible expense for retail sales and transportation customers. The issue is relevant because the Commission does not approve Rider UBA. In this event, and because transportation customers do not ordinarily purchase gas from the Utilities, the gas cost related portion of uncollectible expense must be appropriately removed from the base rates.

We observe that both Mr. Luth and Ms. Grace would recover uncollectible expenses in the distribution rates. And, the respective method employed by the Utilities and Staff do not differ substantially. The Utilities believe that their method is simpler than that proposed by Mr. Luth. Nevertheless, we are informed that the Utilities would find Mr. Luth's methodology acceptable, if corrected to reflect test year gas costs and the appropriate revenues to be used in the determination of the credit for transportation customers' base rates. On this record, the Commission finds that the method for allocating gas cost related uncollectibles expense proposed by Staff is reasonable. That method will allocate the expense to Peoples Gas' S.C. Nos. 1N, 1H, 2 and 4 and North Shore S.C. Nos. 1N, 1H and 2. Further, the method should be supplemented by the corrections proposed by the Utilities.

~~Note: We observe that t~~The AG presents its views in an untimely fashion on Reply Brief. ~~Therefore, neither Staff nor the Utilities had an opportunity to respond. To complete our analysis, we await the Briefs on Exceptions.~~In their Brief on Exceptions, the Utilities responded to the AG's belated arguments, and the Commission finds that response persuasive. The AG's arguments are, essentially, an argument against the S. C. No. 1 rate design and not targeted to the question of the Account No. 904 expense. The Commission concluded the Utilities' S.C. No. 1 rate design was just and reasonable and, therefore, the AG's arguments are rejected.

C. Service Classification Rate Design

2. Contested Issues

a. Peoples Gas Service Classification Nos. 1N and 1H
b. North Shore Service Classification Nos. 1N and 1H

Exception No. 25

The second paragraph of the Commission Analysis and Conclusion on pages 238-239 of the Proposed Order should be revised as follows:

> The Commission also believes that the embedded cost of service study, including, for Peoples Gas, application of the EPEC method, is the most appropriate means of assigning costs to S.C. No. 1N and 1H ~~and the application of the EPEC method in conjunction with the costs study~~ and generates rates that properly reflect a greater recovery of fixed costs as the Commission believes is appropriate. In considering Mr. Glahn's approach, we find it inconsistent and outside the goals of increasing fixed cost recovery. As we see it, Mr. Glahn's proposal would generate rates using the filed revenue requirement that are substantially below those proposed by the Utilities. It is difficult to evaluate in full the propriety of Mr. Glahn's proposal because it is unaccompanied by sufficient analysis or justification in the form of a cost study or some other measure. While the Commission is sensitive to the need to balance social goals with other objectives in its rate design determination, we do not believe the parties opposing the Utilities' proposal have demonstrated that the Utilities have employed anything less than the settled broad objectives of rate design, including social goals, in the S.C. No. 1N and S.C. No. 1H proposals at hand.
>
> In the final analysis and with these same considerations in mind, the Commission believes that the Utilities' proposals represent the most reasoned approach to establishing just and reasonable rates for small residential heating and non-heating customers. Specifically, the Commission adopts: the Utilities' proposed bifurcation of existing S.C. No. 1 into a heating and non-heating service classifications, including the Utilities' method of assigning customers to these new classifications; the Utilities' proposed customer charges (for Peoples Gas, $19 for S.C. No. 1H and $11.25 for S.C. No. 1N; for North Shore, $16 for S.C. No. 1H and $10.50 for S.C. No. 1N); the Utilities' proposals for calculating the distribution rates, including a flat rate for S.C. No. 1N and a declining two-block rate for S.C. No. 1H; Peoples Gas' use of the EPEC method; and setting North Shore's S.C. Nos. 1H and 1N at cost.

X. TRANSPORTATION ISSUES

C. Large Volume Transportation Program

4. Injection, Withdrawal, and Cycling Limits

Exception No. 26

Pages 264-265 of the Order should be revised as follows:

Commission Conclusion

Seasonal Cycling Requirements

In Nicor we approved a fall injection target but not a spring withdrawal target. The Commission concluded that the former was a valid operational requirement that would not unduly burden transportation customers, but the latter was not. Nicor, at 146. We are not persuaded to approve a different regime in these dockets. The Utilities generally assert that "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." That is not enough to outweigh the considerable difficulties the seasonal cycling requirements will present for transportation customers. E.g., CNEG Init. Br. at 20-24. While we are willing to subordinate those difficulties to the Utilities' operational needs during the heating season, the balance tips in the transportation customers' favor in the spring.

We note that the Utilities attempt to elide our Nicor ruling by claiming that "[t]he reason the Commission did not impose a spring withdrawal target on Nicor Gas' transportation customers is that Nicor Gas itself did not routinely operate its system in accordance with the same spring withdrawal targets which it was trying to apply to its transportation customers." PGL-NS Rep. Br. at 150. That is misleading. The Order asserts multiple reasons for our ruling, with the greater emphasis placed on the burden the spring target imposed on transportation customers.

The Commission also observes that the Utilities strongly emphasize the cycling requirements they face with respect to leased storage facilities. Without intending to minimize in any way the significance of those requirements, we see that the larger volume of stored gas managed by PGL resides in Manlove Field, where PGL establishes its own cycling schedule. Thus, most of the Utilities' own storage flexibility is constrained by the general need to recycle Manlove, not by storage leases. That fact, in turn, allows some latitude when balancing the competing and equally legitimate needs of the Utilities and the transporters.

The Commission will not require a common seasonal target for the two Utilities. They correctly demonstrate that they are separate entities with distinct profiles and tariffs. However, in order to ameliorate the impact on North Shore's large volume transportation customers of the Commission's acceptance of daily injection and delivery limits during the injection season pursuant to the immediately subsequent provision of this Order, the Commission will require that North Shore's seasonal injection target be reduced from 85% to 75%.

Exception No. 27

Page 266 of the Order should be revised as follows:

Injection Limits

The Commission readily acknowledges the serious and complex responsibilities the Utilities bear with respect to management of their systems. That does not mean, however, that every measure intended to fulfill those responsibilities optimally balances the interests of all interested parties. The daily delivery constraints the Utilities have proposed to facilitate system management have also raised operational problems for the transporters. The Utilities have forthrightly acknowledged this and have revised their original proposals in response. ~~With regard to daily nominations specifically, it is not apparent to us that the challenges facing the Utilities would be appreciably heightened if the nomination caps for Rider FST and Rider SST were defined by MDQ, on a year-round basis. MDQ is the current benchmark and the Utilities have managed their systems satisfactorily~~Furthermore, two of the Utilities' large volume customers – Vanguard and CNEG – have indicated that they could accept some limitations during the injection season on their ability to nominate gas under Riders FST and SST other than MDQ. Accordingly, the Commission finds it reasonable and appropriate that a transportation customer taking service under Rider FST of either Utility be limited to MDN during the months of April through October of each year, with MDQ to continue to determine its maximum daily nomination during the other months of the year], and that a transportation customer taking service under Rider SST of either Utility have daily injection limits limited to MDN as defined in Rider FST during the months of April through October of each year, with MDQ to continue to determine its maximum daily nomination during the other months of the year. Therefore, as indicated in earlier subsections of this Order, Riders FST and SST are approved subject to our ruling here.

XII. UNION PROPOSALS

A.4 Commission Conclusion re: Merits of the Plan
B.2 Audit of Repairs and Staffing – Commission Conclusion

Exception No. 28

Pages 295 to 298 of the Order should be revised as follows, or in the alternative, as provided in Alternative A:

4. Commission Conclusion re: Merits of the Plan

The Commission finds that the Local has raised serious allegations ~~questions~~ regarding the impact of PGL's staffing and repair practices on employee and public safety. The gravity of the circumstances alleged by the Local is considerable, and it is only heightened by the presence of the Local's membership on the "front line," where the potential for harm to life, health and property is evaluated first-hand. We have no doubts about the ~~credibility or the~~ sincerity of the Local's presentation in these proceedings. Nonetheless, the Commission is not ready to conclude, based on the Local's ground-level view, that PGL's staffing and repair practices do jeopardize, beyond an unavoidable margin of error, the safety of workers and customers or service reliability. ~~While the Local's description of the response to serious (Class I) gas leaks at a Chicago hospital is unquestionably troubling, it remains, as PGL avers, a single example (which, we recognize, is all the Local intended it to be).~~ Additionally, PGL's decision to hire eight outside contractors to perform seasonal and (even from the Local's standpoint) routine tasks is not necessarily indicative of inadequate staffing or unsafe or unreliable conditions. PGL Rep. Br. At 178. Consequently, on the record provided here, the Commission will not require implementation of the Local's staffing plan.

~~The Local's audit recommendation is another story, however. Our hesitation to impose the Local's Plan is not based on evidence disproving its efficacy, but, rather, the absence of systemic statistical evidence that would have persuaded us to adopt the Plan (or something similar) today. Instead of furnishing meaningful record evidence to reassure the Commission and the public that safety and reliability are not at risk due to staffing deficiencies, PGL trivialized the efforts of its own employees to call attention to important concerns. The Commission addresses the proposed audit in the next section of this Order.~~

B. Audit of Repairs and Staffing

1. Parties' Positions and Applicable Law

As noted above, the Local requests an independent audit of: (a) work order response times and backlogs (inclusive of temporary repairs) at PGL; and (b) staffing levels among the workforce that handles those repairs. The Local and PGL concur that express authority to require an audit resides in Section 8-102 of the Act[62], which states:

> [62] 220 ILCS 5/8-102. The Commission also has the general power to "inquire into the management" of a public utility to "keep itself informed as to the manner and method in which the business is conducted…and the manner in which the plants, equipment and other property…are managed, conducted and operated." 220 ILCS 5/4-101. Similarly, a utility "shall furnish" to us "all information required by it to effect the provisions of this Act, and shall make specific answers to all questions submitted by the Commission." 220 ILCS 5/5-101.

The Commission is authorized to conduct or order a management audit or investigation of any public utility or part thereof. The audit or investigation may examine the reasonableness, prudence, or efficiency of any aspect of the utility's operations, costs, management decisions or functions that may affect the adequacy, safety, efficiency or reliability of utility service….

The parties disagree, however, that the necessary findings for a Section 8-102 are supported by the evidentiary record here. Specifically, Section 8-102 authorizes an audit by the Commission "only when it has reasonable grounds to believe that the audit or investigation is necessary to assure that the utility is providing adequate, efficient, reliable and safe least-cost service."

As proof that "reasonable grounds" for an audit or investigation exist, the Local relies on its one example, the gas leak at a Chicago hospital. PGL does not agree that safety was jeopardized in this incident, and also points out that ~~are absent, PGL states that~~ it has already "established a compliance monitoring group that audits compliance with [PGL's] Field Service Manual." PGL-NS Rep. Br. at 179. ~~But other than the bare oral declaration during cross-examination that such a monitoring group is now "performing audits," Tr. 228 (Doerk), PGL provides no information. Thus, PGL does not indicate whether the group scrutinizes the work order backlogs and completion times and repair staffing the Local addresses. PGL also testifies that it is already "working with a Commission hired consultant reviewing all [PGL's] pipeline safety related activities." PGL-NS Ex. 2.0 at 6. But, again, PGL offers nothing more, and the Commission cannot – in view of the Local's detailed evidence and PGL's silence - fulfill its obligations regarding customer and employee safety by simply assuming that a pipeline consultant is reviewing, for example, leak repairs inside or adjacent to customer premises.~~

2. Commission Conclusion

We cannot conclude, without more, that ratepayer's money would be well spent pursuing an audit of leaks and staffing. We do not have before us, either in the record before us or in our knowledge as PGL's regulator, evidence that PGL's workforce is understaffed to the point of safety problems. We cannot say, in accordance with the standards of Section 8-102, that the Commission has reasonable grounds to believe that an audit is necessary. ~~Importantly, PGL acknowledges that it has not compiled information concerning the "use, frequency and duration of average temporary repairs." Tr. 223 (Doerk). Consequently, the record provides no statistical information to either justify the Local's One-for-One proposal or to dismiss the Local's audit request. Therefore, the inferences suggested by the direct observations and anecdotes of Local members - that permanent repairs are not performed soon enough because qualified employees are busy with other work, and that public and employee safety are therefore compromised – are not rebutted. Moreover, there is history of PGL's safety-related deficiencies in the record. PGL confirms that it was fined for failure to conduct required inside safety inspections during the period from 2000 through 2004. *Id.*, 247-48. The Commission concludes that there is reasonable ground to require an appropriately tailored audit of certain aspects of PGL's operations.~~

~~So that the audit results are useful to interested parties, and so that PGL has clear directions, the Commission will sharpen the focus of the Local's audit request ("work order response times and backlogs (inclusive of temporary repairs)"). The safety concerns raised by the Local's testimony, taken as a whole, are associated with the frequency of temporary repairs and the time interval between temporary and permanent repairs.[63/] Consequently, the audit should quantify, for each of the calendar years 2003 through 2007, the total number of gas leaks repaired by PGL, and the total number and percentage of those in which temporary repairs were used. Separate data should be presented for each class of gas leak (i.e., Classes I through III). The audit should also quantify the percentage (of all gas leaks repaired) and number of temporarily repaired gas leaks for which permanent repairs were completed in one, two, three, four, five, and more than five business days. Again, separate data should be presented for each class of gas leak.~~

~~[63/] E.g., "Our experience is that temporary repairs are used routinely and extensively throughout [PGL's] service territory, and that the period of time between when a temporary repair is implemented and a permanent repair is completed is growing significantly. This is not a tolerable state-of-affairs because gas leaks that are not fully repaired do not get better on their own, they can only get worse. In my experience and those of other Local 18007 employees, the Company does encourage the frequent use of temporary repairs as a stopgap measure to respond to work orders quickly." UWUA Ex. 2.0 at 13.~~

~~With respect to staffing, the Local's audit request ("staffing levels among the utility workforce at PGL") also needs narrowing. The Local's~~

~~testimony, taken as a whole, associates safety issues with insufficient staffing of "top-tier" positions among PGL's work force, particularly Senior Service Specialist No. 1 in the Service Department and Crew Leader in the Distribution Department[64/]. Therefore, the audit should quantify, for each of the calendar years 2003 through 2007, the total number and percentage of gas leaks repaired by PGL in which a CL or SSS-1 participated, the total number and percentage of those in which temporary repairs were used, and the total number of such gas leaks assigned per CL and SSS-1 during each month. Separate data should be presented for each class of gas leak (i.e., Classes I through III).~~

~~[64/]E.g., the Local "testified that lag times to complete permanent repairs are expanding, and that the use of temporary repairs is increasing. Based on experience in the field, the [Local] asserts that the reason for the lengthening lag is a shortage in the ranks of those highly-skilled employees without whom permanent repairs cannot be conducted." Local Init. Brief at 3.~~

~~PGL and the Local are the entities most familiar with the pertinent subject matter. Accordingly, the Commission encourages them to expand or reorganize – by mutual agreement - the focus of the audit to make its results as useful as is practicable. Any such expansions or revisions should be explained in the final report to the Commission.~~

~~The audit shall be completed and its results submitted to the Commission's Staff within the 180 days after the entry of this Order. Contemporaneous with such submission, PGL shall provide a copy of the audit results to the Local, subject to execution by the Local of a reasonable confidentiality pledge, if such pledge is requested by PGL. The audit results shall be attested to by the auditing party.~~

~~Although the Local requests an independent audit, the Commission sees no reason why PGL personnel should be precluded from performing the audit and attesting to their results. Regarding costs, the audit described above is not materially different from responding to discovery requests in proceedings like these. PGL should bear such costs and include them in its expense calculations in a subsequent rate case. If PGL, at its discretion, instead elects to hire an independent auditor, Section 8-102 states that "the cost of an independent audit shall be borne initially by the utility, but shall be recovered as an expense through normal ratemaking procedures." By its terms, this is a mandatory cost allocation and recovery scheme and the Commission must implement it in this instance.~~

<u>Alternative A</u>

4. <u>Commission Conclusion re: Merits of the Plan</u>

The Commission finds that the Local has raised serious <u>allegations</u> ~~questions~~ regarding the impact of PGL's staffing and repair practices on employee and public safety. The gravity of the circumstances alleged by the Local is considerable, and it is only heightened by the presence of the Local's membership on the "front line," where the potential for harm to life, health and property is evaluated first-hand. We have no doubts about the ~~credibility or the~~ sincerity of the Local's presentation in these proceedings. Nonetheless, the Commission is not ready to conclude, based on the Local's ground-level view, that PGL's staffing and repair practices do jeopardize, beyond an unavoidable margin of error, the safety of workers and customers or service reliability. ~~While the Local's description of the response to serious (Class I) gas leaks at a Chicago hospital is unquestionably troubling, it remains, as PGL avers, a single example (which, we recognize, is all the Local intended it to be).~~ Additionally, PGL's decision to hire eight outside contractors to perform seasonal and (even from the Local's standpoint) routine tasks is not necessarily indicative of inadequate staffing or unsafe or unreliable conditions. PGL Rep. Br. At 178. Consequently, on the record provided here, the Commission will not require implementation of the Local's staffing plan.

The Local's audit recommendation is another story, however. ~~Our hesitation to impose the Local's Plan is not based on evidence disproving its efficacy, but, rather, the absence of systemic statistical evidence that would have persuaded us to adopt the Plan (or something similar) today. Instead of furnishing meaningful record evidence to reassure the Commission and the public that safety and reliability are not at risk due to staffing deficiencies, PGL trivialized the efforts of its own employees to call attention to important concerns.~~ The Commission addresses the proposed audit in the next section of this Order.

B. Audit of Repairs and Staffing

1. Parties' Positions and Applicable Law

As noted above, the Local requests an independent audit of: (a) work order response times and backlogs (inclusive of temporary repairs) at PGL; and (b) staffing levels among the workforce that handles those repairs. The Local and PGL concur that express authority to require an audit resides in Section 8-102 of the Act[62/], which states:

[62/] 220 ILCS 5/8-102. The Commission also has the general power to "inquire into the management" of a public utility to "keep itself informed as to the manner and method in which the business is conducted…and the manner in which the plants, equipment and other property…are managed, conducted and operated." 220 ILCS 5/4-101. Similarly, a utility "shall furnish" to us "all information required by it to effect the provisions of this Act, and shall make specific answers to all questions submitted by the Commission." 220 ILCS 5/5-101.

The Commission is authorized to conduct or order a management audit or investigation of any public utility or part thereof. The audit or investigation may examine the reasonableness, prudence, or efficiency of any aspect of the utility's operations, costs, management decisions or functions that may affect the adequacy, safety, efficiency or reliability of utility service….

The parties disagree, however, that the necessary findings for a Section 8-102 are supported by the evidentiary record here. Specifically, Section 8-102 authorizes an audit by the Commission "only when it has reasonable grounds to believe that the audit or investigation is necessary to assure that the utility is providing adequate, efficient, reliable and safe least-cost service."

As proof that "reasonable grounds" for an audit or investigation exist, the Local relies on its one example, the gas leak at a Chicago hospital. PGL does not agree that safety was jeopardized in this incident, and also points out that ~~are absent, PGL states that~~ it has already "established a compliance monitoring group that audits compliance with [PGL's] Field Service Manual." PGL-NS Rep. Br. at 179. ~~But other than the bare oral declaration during cross-examination that such a monitoring group is now "performing audits," Tr. 228 (Doerk), PGL provides no information. Thus, PGL does not indicate whether the group scrutinizes the work order backlogs and completion times and repair staffing the Local addresses. PGL also testifies that it is already "working with a Commission hired consultant reviewing all [PGL's] pipeline safety related activities." PGL-NS Ex. 2.0 at 6. But, again, PGL offers nothing more, and the Commission cannot – in view of the Local's detailed evidence and PGL's silence - fulfill its obligations regarding customer and employee safety by simply assuming that a pipeline consultant is reviewing, for example, leak repairs inside or adjacent to customer premises.~~

2. Commission Conclusion

Importantly, PGL acknowledges that it has not compiled information concerning the "use, frequency and duration of average temporary repairs." Tr. 223 (Doerk). Consequently, the record provides no statistical information to either justify the Local's One-for-One proposal or to dismiss the Local's audit request. Therefore, the inferences suggested by the direct observations and anecdotes of Local members - that permanent repairs are not performed soon enough because qualified employees are busy with other work, and that public and employee safety are therefore compromised – are not rebutted. Moreover, there is history of PGL's safety-related deficiencies in the record. PGL confirms that it was fined for failure to conduct required inside safety inspections during the period from 2000 through 2004. *Id*., 247-48. The Commission concludes that there is reasonable ground to require an appropriately tailored audit of certain aspects of PGL's operations.

So that the audit results are useful to interested parties, and so that PGL has clear directions, the Commission will ~~sharpen the focus of the Local's audit request ("work order response times and backlogs (inclusive of temporary repairs)"). The safety concerns raised by the Local's~~

~~testimony, taken as a whole, are associated with the frequency of temporary repairs and the time interval between temporary and permanent repairs.[63/] Consequently, the audit should quantify, for each of the calendar years 2003 through 2007, the total number of gas leaks repaired by PGL, and the total number and percentage of those in which temporary repairs were used. Separate data should be presented for each class of gas leak (i.e., Classes I through III). The audit should also quantify the percentage (of all gas leaks repaired) and number of temporarily repaired gas leaks for which permanent repairs were completed in one, two, three, four, five, and more than five business days. Again, separate data should be presented for each class of gas leak.~~

> ~~[63/] E.g., "Our experience is that temporary repairs are used routinely and extensively throughout [PGL's] service territory, and that the period of time between when a temporary repair is implemented and a permanent repair is completed is growing significantly. This is not a tolerable state-of-affairs because gas leaks that are not fully repaired do not get better on their own, they can only get worse. In my experience and those of other Local 18007 employees, the Company does encourage the frequent use of temporary repairs as a stopgap measure to respond to work orders quickly." UWUA Ex. 2.0 at 13.~~

~~With respect to staffing, the Local's audit request ("staffing levels among the utility workforce at PGL") also needs narrowing. The Local's testimony, taken as a whole, associates safety issues with insufficient staffing of "top-tier" positions among PGL's work force, particularly Senior Service Specialist No. 1 in the Service Department and Crew Leader in the Distribution Department.[64/] Therefore, the audit should quantify, for each of the calendar years 2003 through 2007, the total number and percentage of gas leaks repaired by PGL in which a CL or SSS-1 participated, the total number and percentage of those in which temporary repairs were used, and the total number of such gas leaks assigned per CL and SSS-1 during each month. Separate data should be presented for each class of gas leak (i.e., Classes I through III).~~

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~~PGL and the Local are the entities most familiar with the pertinent subject matter. Accordingly, the Commission encourages them to expand or reorganize – by mutual agreement - the focus of the audit to make its results as useful as is practicable. Any such expansions or revisions should be explained in the final report to the Commission.~~

~~The~~ not specify the precise scope of the audit in this order, but will order PGL to work with Local 18007 and the Commission's Natural Gas Pipeline Safety Section to agree on the scope. Absent an agreement among these three to a more appropriate timeframe, the audit shall be completed and its results submitted to the Commission's Staff within the 180 days after the entry of this Order. Contemporaneous with such submission, PGL shall provide a copy of the audit results to the Local, subject to execution by the Local of a reasonable confidentiality pledge, if such pledge is requested by PGL. The audit results shall be attested to by the auditing party.

Although the Local requests an independent audit, the Commission sees no reason why PGL personnel should be precluded from performing the audit and attesting to their results. Regarding costs, the audit described above is not materially different from responding to discovery requests in proceedings like these. PGL should bear such costs and include them in its expense calculations in a subsequent rate case. If PGL, at its discretion, instead elects to hire an independent auditor, Section 8-102 states that "the cost of an independent audit shall be borne initially by the utility, but shall be recovered as an expense through normal ratemaking procedures." By its terms, this is a mandatory cost allocation and recovery scheme and the Commission must implement it in this instance.

XIII. FINDING AND ORDERING PARAGRAPHS

Exception No. 29

Pages 299-300 of the Order should be revised as follows:

Finding and Ordering Paragraphs 7, 8, 9, 10, 11, 12, 17, and 18 should be revised to reflect the quantitative impacts of the Utilities' Exception Nos. 1 through 14, discussed above. More specifically:

- Finding 7 should be revised to reflect the Peoples Gas approved rate base figure that results from Exception Nos. 1 through 8;
- Finding 8 should be revised to reflect the North Shore approved rate base figure that results from Exception Nos. 1 through 8, and the delete the extra "$";

- Finding 9 should be revised to reflect an approved ROE for Peoples Gas of 11.06% and the resulting overall rate of return, as results from Exception Nos. 12 through 14;
- Finding 10 should be revised to reflect an approved ROE for North Shore of 11.06% and the resulting overall rate of return, as results from Exception Nos. 12 through 14;
- Finding 11 should be revised to reflect the impacts on Peoples Gas' net operating income of Exception Nos. 1 through 14;
- Finding 12 should be revised to reflect the impacts on North Shore's net operating income of Exception Nos. 1 through 14;
- Finding 17 should be revised to reflect the impacts on Peoples Gas' revenue requirement, and the resulting rate increase, of Exception Nos. 1 through 14; and
- Finding 18 should be revised to reflect the impacts on North Shore's revenue requirement, and the resulting rate increase, of Exception Nos. 1 through 14.

APPENDIX A

Exception No. 30

Appendix A should be revised to reflect not only the correction of the mathematical errors addressed by the Utilities' Exception Nos. 1 through 4, but also the quantitative impacts of Exception Nos. 5 through 14, and the additional corrections discussed in the Utilities' Brief on Exceptions with regard to Exception No. 30.

APPENDIX B

Exception No. 31

Appendix B should be revised to reflect not only the correction of the mathematical errors addressed by the Utilities' Exception Nos. 1 through 4, but also the quantitative impacts of Exception Nos. 5 through 14, and the additional corrections discussed in the Utilities' Brief on Exceptions with regard to Exception No. 31.

Dated: December 14, 2007

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