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.	:	

BRIEF ON EXCEPTIONS OF
NORTH SHORE GAS COMPANY AND THE
PEOPLES GAS LIGHT AND COKE COMPANY

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BRIEF ON EXCEPTIONS OF NORTH SHORE GAS COMPANY AND THE PEOPLES GAS LIGHT AND COKE COMPANY

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 Brief on Exceptions and are separately filing Exceptions to the Proposed Order (the "NS-PGL Exceptions") containing proposed revised and replacement language in black-lined format.

INTRODUCTION AND SUMMARY

These are the Utilities' first rate cases since 1995, and their first since Integrys Energy Group, Inc. ("Integrys"), became their ultimate parent company. Peoples Gas and North Shore filed new and revised tariffs that: (1) reflect the changes in their costs of service and the causation of those costs; (2) in the case of Peoples Gas, enable improvement of the infrastructure of the City of Chicago by providing for accelerated replacement of the cast iron and ductile iron main system; (3) mitigate the effects of unusually cold or unusually warm weather on gas bills and revenues; and (4) improve the Utilities' current transportation programs.

The Proposed Order's recommendations on most issues are consistent with the evidence in the record, but they should be modified in four major respects (one of which does not involve the merits of any issue but rather the correction of certain mathematical errors in the Appendices to the Proposed Order). These subjects are briefly overviewed in this Introduction and are discussed in detail later in the body of this Brief on Exceptions.

First, the Proposed Order is inconsistent with the governing constitutional and statutory law and with the evidence in the record because it recommends **rates of return on common equity** ("ROEs") that are not consistent with the realistic evidence on the Utilities' actual costs of equity. If adopted by the Commission, the Proposed Order's recommended ROEs of 9.70% for Peoples Gas and 9.50% for North Shore would be lower than any ROEs that the Commission has set for any gas utility in over 30 years. The law and the evidence do not support those results.

The primary cause of the incorrectly low ROEs, which are based on the simple averages of Staff's discounted cash flow ("DCF") analysis and Staff's Capital Asset Pricing Model ("CAPM") analysis, then reduced by Staff's "financial risk" adjustments, is that Staff's DCF analysis is so flawed that it produces results that do not pass any "reality check". For example, Staff's DCF analysis, which suggests an ROE for Peoples Gas of 8.23% (unadjusted), also suggests an ROE for Nicor Gas of 5.91%, which is less than current utility bond yields. The ROE figure that Staff's DCF analysis suggests for Nicor Gas is over 400 basis points lower than the Nicor Gas' cost of equity of 10.51% as determined by the Commission in September 2005. Staff's DCF number for Nicor Gas simply cannot be correct, and Staff has not been able to explain its DCF model's result for Nicor Gas. There is no reasonable explanation. Staff's DCF Model produces unreasonable results.

Even if various of the Proposed Order's recommended findings on specific issues relating to the determination of ROEs were to be accepted, those rulings would result in significantly higher ROEs than the Proposed Order recommends. As explained below, if the Commission disregarded Staff's DCF results and, consistent with its prior decisions, the Utilities' Risk Premium Model results, then the Utilities' costs of equity based on the remaining Staff and Utility results would be 10.91% including the Utilities' 52 basis point financial leverage adjustment (the figure without that adjustment would be 10.38%, due to rounding), which is required to give the Utilities an opportunity to earn their authorized return. Staff's specific "financial risk" adjustments are not supported by the evidence in these cases.

The Proposed Order's recommended ROEs would send an especially sharp and unfortunate negative signal to the financial markets. The recommendations follow on the heels of Integrys' becoming the ultimate parent company of the Utilities, a transaction that the Commission itself approved on Conditions that no one disputes the Utilities have met or exceeded in all respects. The Utilities' proposed ROE, unlike the recommended ROEs, fall within the range of what is reasonable and should be approved.

Second, the Proposed Order fails to recommend adoption of Peoples Gas' proposed infrastructure rider, "**Rider ICR**". Rider ICR, by providing for timely recovery of the associated costs, would allow Peoples Gas to accelerate the replacement of cast iron and ductile iron mains in the City of Chicago, to the general benefit of customers and the City. The City's strong support of this Rider emphasizes that the municipal government for Peoples Gas' jurisdiction (the governmental entity most directly impacted by Rider ICR) recognizes the importance of this rider to the citizens of the City of Chicago. The regulatory lag between rate cases, at least those using historical test years with *pro forma* adjustments, means that there is no other mechanism that offers the opportunity for full recovery of these costs. While Peoples Gas does not agree with the concerns expressed by the Proposed Order on the subject of Rider ICR, Peoples Gas' revised Proposed Order language contains two modifications based on those concerns, i.e., to add a rate base deduction for Accumulated Deferred Income Taxes and anticipated operating expense savings offsets to the calculation of the costs to be recovered under Rider ICR. The Commission should approve Rider ICR with those modifications.

Third, the Utilities respectfully suggest that the Proposed Order also misses an opportunity that is in the best interests of customers when it rejects **the proposed decoupling rider**, "Rider VBA". Decoupling riders are being proposed and in many instances adopted throughout the country to align utilities' interests with those of their customers as the industry attempts to address climate change. Rider VBA should be approved.

Fourth, the Proposed Order in its two Appendices contain some serious **mathematical errors** in calculating the amounts of Cash Working Capital ("CWC") to include in the Utilities' rate bases. The Proposed Order's recommendations expressly accept only in part Staff's proposed downward adjustments to CWC and reject the remainder. Yet, the Appendices impose several times larger subtractions for CWC than Staff proposed.[1] (No other party proposed any CWC adjustments.) That anomaly is the result of three sets of mathematical errors that are inconsistent with the Proposed Order's actual findings: (1) incorrectly including pass through tax

[1] Peoples Gas and North Shore proposed to include $30,896,000 and ($1,124,000) of CWC in rate base, respectively. Staff proposed final revised downward adjustments to those figures of $14,315,000 and $622,000. Yet, while the text of the Proposed Order expressly approves only part of Staff's proposed adjustments to CWC and rejects the rest, the Appendices to the Proposed Order, without explanation and incorrectly, as a matter of mathematics, subtract $43,018,000 as to Peoples Gas and $3,421,000 as to North Shore for CWC.

dollars on the expense side but not on the revenue side of the CWC calculations; (2) incorrectly including certain non-cash items; and (3) incorrectly excluding expensed amounts for payroll and payroll-related expenditures and incorrectly including capitalized amounts for payroll and payroll-related expenditures. Peoples Gas and North Shore have presented corrected calculations that are consistent with the Proposed Order's recommendations. Those corrections should be made.

Peoples Gas and North Shore also present Exceptions on certain other points where the Proposed Order is not consistent with the evidence in the record or it should be clarified or amplified. As noted above, consistent with the Commission's Rules of Practice, the Utilities are submitting this Brief on Exceptions and are separately filing Exceptions to the Proposed Order containing proposed revised and replacement language in black-lined format. The Utilities' Exceptions should be approved.

ARGUMENT IN SUPPORT OF 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 Nos. 1-4

The Companies are not filing Exceptions to the cash working capital ("CWC") discussion, analyses, and conclusions included in the text of the Proposed Order. Proposed Order at 18-23. However, as indicated in The Peoples Gas Light and Coke Company's and North Shore Gas Company's Motion to Correct Mathematical Errors in the Appendices to the

Proposed Order, filed on December 5, 2007, which they incorporate herein,[2] the Companies do take Exception to mathematical errors in the CWC calculations included in the Appendices to the Proposed Order that are inconsistent with the rulings in the body of the Proposed Order.

The CWC calculations included in the Appendices to the Proposed Order: (i) incorrectly fail to exclude all non-cash items, contrary to the rulings in the body of the Proposed Order; and (ii) incorrectly implement the Proposed Order's directives regarding capitalized payroll-related expenditures and pass through taxes. *See* Proposed Order at 19-22. Accordingly, the Companies' CWC requirements, as calculated in the four applicable pages of the Appendices to the Proposed Order (Proposed Order, Appendix ("App.") A, pp. 10-11, and App. B, pp. 10-11) should be revised, as shown in Exception Nos. 1-4, respectively, in the Utilities' separately filed NS-PGL Exceptions. In particular, as a result of the corrections shown in those Exceptions, Peoples Gas' corrected CWC requirement included in rate base should be $24,949,000, and North Shore's corrected CWC requirement should be negative $1,343,000.

As the Administrative Law Judges and the Commission are aware, when a rate base, operating expenses, or revenues figure that is part of the computation of a utility's revenue requirement is corrected or modified, that affects other amounts in those computations that are derivative of that figure, and it affects the ultimate revenue requirement. Thus, correction of the Companies' CWC requirements, as calculated in the four applicable pages of the Appendices to the Proposed Order, also will affect other computations in those Appendices, and it also will affect the portions of the body of the Proposed Order where figures in those computations and their results are stated.

[2] On December 7, 2007, the ALJs ruled that the issues raised in the motion should be addressed in the briefing of Exceptions, if at all, rather than in motion practice.

Therefore, the Utilities, in addition to proposing the specific corrections shown in Exception Nos. 1-4 in the Utilities' separately filed NS-PGL Exceptions, also request that all other amounts in the Appendices and in the text of the Proposed Order that are affected by those corrections also be accordingly corrected. The mathematical errors that are the subject of those four Exceptions are discussed further in the following three subsections of this Brief on Exceptions.

1. <u>Removal of Depreciation and Amortization</u>

As noted in the Proposed Order, in a gross lag study of CWC requirements, "[a]djustments remove non-cash items, such as depreciation and uncollectibles, that are unavailable to pay expenses". Proposed Order at 19, fn. 3. Thus, amounts reflecting depreciation and amortization must be removed when calculating the Companies' CWC requirements. However, as detailed below, the CWC calculations included in the Appendices to the Proposed Order incorrectly fail to exclude depreciation and amortization.

With respect to Peoples Gas, the CWC calculations include $130,393,000 for "Other Operations and Maintenance" (Proposed Order, App. A, p. 10, line ("ln.") 6), which was derived by making various adjustments to "O&M Expenses". Proposed Order, App. A, p. 11, lns. 10-15. The calculations on Page 11 of Appendix A show that Peoples Gas' "O&M Expenses" incorrectly include "Depreciation and Amortization" in the amount of $59,203,000. *Compare* Proposed Order, App. A, p. 1, ln. 14 and ln. 19; *with* Proposed Order, App. A, p. 11, lns. 10-15. Thus, the "O&M Expenses" used to calculate Peoples Gas' "Other Operations and Maintenance" expense are overstated by $59,203,000. *See* corrected calculations in Exception No. 1 in the NS-PGL Exceptions.

The CWC calculations for North Shore are similarly flawed. The CWC calculations for North Shore include $13,696,000 for "Other Operations and Maintenance" (Proposed Order, App. B, p. 10, ln. 6), which was derived by making various adjustments to "O&M Expenses". Proposed Order, App. B, p. 11, lns. 10-15. North Shore's "O&M Expenses" incorrectly include "Depreciation" in the amount of $6,094,000. *Compare* Proposed Order, App. B, p. 1, ln. 14 and ln. 19 *with* Proposed Order, App. B, p. 11, lns. 10-15. Thus, the "O&M Expenses" used to calculate North Shore's "Other Operations and Maintenance" expense are overstated by $6,094,000. *See* corrected calculations in Exception No. 3 in the NS-PGL Exceptions.

2. <u>Exclusion of Capitalized Payroll-Related Expenditures</u>

The Proposed Order properly adopts the Companies' contention that capitalized payroll-related expenditures should not be included in CWC calculations. Proposed Order at 20-21. Thus, only expensed payroll-related items should be taken into account. Accordingly, in calculating the Companies' CWC requirements, expensed payroll-related items (*i.e.*, expenses for "Pension and Benefits", "Payroll and Withholdings", and "Inter Company Billings") should be expressly included in expenses and, to avoid double-counting, deducted from the Companies' "O&M Expenses".

As set forth on Page 11 of Appendix A to the Proposed Order, during the test year ended September 30, 2006, Peoples Gas incurred expenses for "Pension and Benefits" in the amount of $31,011,000 and expenses for "Payroll and Withholdings" in the amount of $58,223,000. Proposed Order, App. A, p. 11, lns. 11 and 12; *see also* PGL Exhibit ("Ex.") MJA-1.1, Schedule ("Sch.") B-8, p. 1, column ("Col.") H, lns. 1 and 2. During the same time period, Peoples Gas incurred expenses for "Inter Company Billings" equal to $48,189,000. PGL Ex. MJA-1.1, Sch. B-8, p. 1, Col. H, ln. 3. (Appendix A to the Proposed Order inaccurately states that Peoples Gas' "Inter Company Billings" expense was $66,656,000. Proposed Order, App. A, p. 11, ln. 14.) To accurately calculate Peoples Gas' CWC requirement, the foregoing payroll-related expenses should be directly included in Peoples Gas' expenses and subtracted from its "O&M Expenses". *See* corrected calculations in Exception Nos. 1 and 2 in the NS-PGL Exceptions.

As set forth on Page 11 of Appendix B to the Proposed Order, during the test year ended September 30, 2006, North Shore incurred expenses for "Pension and Benefits" in the amount of $4,765,000 and expenses for "Payroll and Withholdings" in the amount of $5,220,000. Proposed Order, App. B, p. 11, lns. 11 and 12; *see also* NS Ex. MJA-1.1, Sch. B-8, p. 1, Col. H, lns. 1 and 2. During the same time period, North Shore incurred expenses for "Inter Company Billings" equal to $11,233,000. NS Ex. MJA-1.1, Sch. B-8, p. 1, Col. H, ln. 3. (Appendix B to the Proposed Order inaccurately states that North Shore's "Inter Company Billings" expense was $17,234,000. Proposed Order, App. B, p. 11, ln. 14.) To accurately calculate North Shore's CWC requirement, the foregoing payroll-related expenses should be directly included in North Shore's expenses and subtracted from its "O&M Expenses". *See* corrected calculations in Exception Nos. 3 and 4 in the NS-PGL Exceptions.

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

The Proposed Order resolves the Companies' and Staff's dispute regarding pass through taxes by approving of the Companies' use of pass through taxes to calculate the expense lead time for Taxes Other Than Income Taxes and requiring the Companies to utilize the dollar amount of pass through taxes to calculate cash flows associated with Taxes Other Than Income Taxes. Proposed Order at 21-22. Thus, in calculating the Companies' CWC requirements, the dollar amounts of pass through taxes must be included in both revenues and expenses. *See id.*

at 22 ("The Utilities collect money from ratepayers to meet governmental obligations, then meet those obligations with later payments.").

The CWC calculations included in the Appendices to the Proposed Order only include pass through taxes (together with other non-income taxes) in expenses. *See* Proposed Order, App. A, p. 10, lns. 1 and 7, p. 11, lns. 1-6 and p. 13, ln. 19; App. B, p. 10, lns. 1 and 7, p. 11, lns. 1-6 and p. 13, ln. 14. Accordingly, the calculations must be revised to include pass through taxes in revenues.

For the test year ended September 30, 2006, Peoples Gas collected $205,491,070 in pass through taxes ($224,009,070 total Taxes Other Than Income Taxes - $18,518,000 non-income, non-pass through taxes). Proposed Order, App. A, p. 1, ln. 17 and p. 13, ln. 19. Accordingly, the revenues included in the CWC calculations for Peoples Gas should equal $1,555,980,070 ($205,491,070 + $1,350,489,000) rather than $1,350,489,000. *See* corrected calculations in Exception Nos. 1 and 2 in the NS-PGL Exceptions.

For the test year ended September 30, 2006, North Shore collected $18,991,243 in pass through taxes ($21,026,243 total Taxes Other Than Income Taxes - $2,035,000 non-income, non-pass through taxes). Proposed Order, App. B, p. 1, ln. 17 and p. 13, ln. 14). Accordingly, the revenues included in the CWC calculations for North Shore should equal $285,867,243 ($18,991,243 + $266,876,000) rather than $266,876,000. *See* corrected calculations in Exception Nos. 3 and 4 in the NS-PGL Exceptions. Exception Nos. 1 through 4 should be adopted.

F. Gas in Storage

1. Working Capital

Exception No. 5

The Proposed Order approves Staff's proposed "working capital" adjustments to the Utilities' Gas in Storage amounts included in rate base. Proposed Order at 26-27. The Proposed Order's recommendation is inconsistent with the evidence in the record.

The cost of the Utilities' gas sold to customers is recovered through the purchased gas adjustment rider as the gas is withdrawn from the storage field and sold to customers. However, most stored gas is injected during the non-winter months, so there is a lag between the time the gas is purchased by the utility and injected into storage, and when it is sold. A utility, therefore, has a working capital allowance in rate base for the value of its working gas in storage. Peoples Gas' working capital allowance for Gas in Storage is $86,667,000, and North Shore's is $10,507,000, based on the applicable 13 month averages as of the end of the test year. Proposed Order at 24; *e.g.*, Fiorella Direct ("Dir."), PGL Ex. SF-1.0 at 15-16; PGL Ex. SF-1.1, Sch. B-1, ln. 6, and Sch. B-8.1, Col. [M]; Fiorella Dir., NS Ex. SF-1.0 at 15; NS Ex. SF-1.1, Sch. B-1, ln. 6, and Sch. B-8.1, Col. [M].

The Proposed Order approves Staff's proposed cost disallowance equivalent to about 6.9 Bcf of gas for Peoples Gas and about 0.9 Bcf for North Shore. Proposed Order at 24, 26-27. Staff primarily argued that because Peoples Gas had more gas in inventory at the end of the year than during other recent years, the difference should be disallowed. *See* Lounsberry Dir., Staff Ex. 11.0 at 6-7, *et seq*.; Lounsberry Rebuttal ("Reb."), Staff Ex. 23.0, Scheds. 23.1N and 23.1P.

The difference between the test year and the previous two years was primarily weather. The winter in early 2006 was exceptionally warm, so Peoples Gas did not pull as much gas out of storage to meet customer needs. Zack Reb., NS-PGL Ex. TZ-2.0, at 74. As Staff concedes, a utility does not necessarily cycle all of its working gas, depending on how cold the winter is. D. Anderson, Tr. at 473:11-18. If a utility injected more gas into an aquifer like Manlove field than it withdrew the previous season, then it would wind up with more gas underground than it had before. D. Anderson, Tr. at 473:19 - 474:1.

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

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, at 11; Fiorella Dir., NS Ex. SF-1.0, at 11. In no event, should it be a disallowance. There is no evidence of imprudence. Accordingly, the Proposed Order should be revised as shown in Exception No. 5 in the NS-PGL Exceptions.

2. <u>Accounts Payable</u>

<u>Exception No. 6</u>

The Proposed Order (at 31) accepts Staff's proposed "accounts payable" adjustments to the Utilities' Gas in Storage amounts included in rate base. The Proposed Order's recommendation appears to have been swayed by two arguments: (1) that "the Companies should not earn a return on the storage gas until it has been funded by investors", Kahle Corr. Supplemental ("Supp.") Dir., Staff Ex. 3.0 Supp., at 2; and (2) that there are "a number of other cases" where the Commission has made "similar adjustments". Proposed Order at 31. Those arguments are inconsistent with the evidence in the record.

First, North Shore and Peoples Gas witness Mr. Fiorella provided uncontradicted testimony that the Utilities paid for the Gas in Storage in rate base, and that there are no accounts payable for the Gas in Storage in rate base because, under the applicable standard contract, the Utilities paid for this storage gas within no more 16 days from the receipt of the invoices from the vendors. Fiorella Supp. Reb., NS-PGL Ex. 3.0, at 2; NS-PGL Initial Brief ("Init. Br.") at 29-30; NS-PGL Reply Brief ("Rep. Br.") at 26. The fact is that the Gas in Storage in rate base is fully funded by investors and has been for well over a year. The evidence of that fact is uncontradicted and should be conclusive on this issue, because Staff's own witness, in his direct testimony, agreed that storage gas should be included in rate base if it has been funded by the Utilities. *See* Kahle Corr. Supp. Dir., Staff Ex. 3.0 Supp., at 2; NS-PGL Init. Br. at 29-30; NS-PGL Reply Br. at 26.

Staff's witness does not and cannot deny that that "financing" consists of nothing more than the fact that the Utilities pay vendors' invoices for storage gas in no more than 16 days. He does not and cannot deny that the Utilities must, and do, pay those invoices. Staff's position, therefore, unreasonably seeks to deny the Utilities recovery of and on substantial amounts of their actual historical investments in the Gas in Storage in rate base simply because the Utilities do not instantly pay for Gas in Storage.

Second, the Proposed Order's reliance on Staff's citation of five prior Orders regarding accounts payable offsets to Gas in Storage balances is misplaced. Kahle Corr. Reb., Staff Ex. 15.0, at 20; Staff Init. Br. at 15-16. The Commission should disregard these Orders because they involve a future test year, not an historical test year. They do not fit the facts, are inappropriate, and unfairly fail to take into account regulatory lag (*i.e.*, the delay between the large cost under-recovery experienced by the Utilities during the test year through the period when the rates will go into effect beginning in 2008). Fiorella Supp. Reb., NS-PGL Ex. SF-3.0, at 3–4; Fiorella Sur., NS-PGL Ex. 4.0, at 7–8; NS-PGL Init. Br. at 31; NS-PGL Reply Br. at 28.

In sum, Staff's proposed adjustments to impose accounts payable offsets against the Gas in Storage in rate base lack merit and should not be approved. The Utilities' Gas in Storage in their rate bases should be approved in full, not offset by accounts payable to deny them recovery on amounts they in fact have paid. The Proposed Order, therefore, should be revised as shown in Exception No. 6 in the NS-PGL Exceptions.

G. <u>OPEB Liabilities and Pension Asset/Liability</u>

<u>Exception No. 7</u>

Although the Proposed Order properly acknowledges the Utilities' respective contributions to their pension plans during the test year, the Proposed Order errs in accepting GCI's and Staff's one-sided arguments in deducting the Utilities' accrued OPEB liabilities while only recognizing the test year pension contributions, rather than the entire pension asset of Peoples Gas as an offset, and, to be consistent, recognizing the pension liability of North Shore as an additional adjustment. Proposed Order at 35-36. The recommended adjustments, more specifically, are incomplete and one-sided because they exclude Peoples Gas' net pension asset of $110,000,000 and North Shore's net pension liability of $24,000 in the calculation of the Utilities' rate bases. Kallas Reb., NS-PGL Ex. LK-2.0 REV, at 13; NS-PGL Init. Br. at 31-32. Accordingly, the Proposed Order should be revised as set forth in Exception No. 7 in the NS-PGL Exceptions, which provides for making neither the OPEB liabilities adjustments nor the pension contribution offsets and, in the alternative, provides for making the OPEB liabilities adjustments and the pension asset / liability adjustments.

Staff claims that subtracting the OPEB liabilities from rate base while ignoring the pension asset/liability is consistent with "ratemaking theory" because "the respective asset/liability was not created with funds supplied by shareholders"; therefore, according to Staff, shareholders do not need to earn a return on those amounts. Pearce Reb., Staff Ex. 14.0, at 22; Staff Init. Br. at 18. This argument completely ignores the uncontested facts, accepted by the Proposed Order, that Peoples Gas' net pension asset reflects that it contributed $15,278,614 to the pension plan during the test year, while North Shore's very small pension liability reflects that it contributed $1,862,247 to the pension plan during the test year. Kallas Sur., NS-PGL Ex. LMK-3.0, at 3; NS-PGL Reply Br. at 29.

Further, ratepayers have benefited from the Utilities' contributions to the pension plans. In calculating their proposed revenue requirements, the levels of pension expense in the test year were reduced by the Utilities' *pro forma* adjustments to reflect the lower levels of pension expense in fiscal year 2007, in the gross amounts of $1,277,000 as to Peoples Gas and $490,000 as to North Shore. Fiorella Dir., PGL Ex. SF-1.0, at 27; PGL Ex. SF-1.1, Sched. C-1, column [D], Sched. C-2, p. 1, line 15, and Sched. C-2.15; Fiorella Dir., NS Ex. SF-1.0, at 25; NS

Ex. SF-1.1, Sched. C-1, column [D], Sched. C-2, p. 2, line 15, and Sched. C-2.15; NS-PGL Init. Br. at 32; NS-PGL Reply Br. at 29-30.

Finally, the Nicor Orders cited by Staff are distinguishable. In the 2004 Nicor rate case, the Commission expressly noted that Nicor Gas acknowledged that it had made no pension plan contributions since the 1995 case. *In re Northern Illinois Gas Co.*, ICC Docket No. 04-0779, p. 22 (Order Sept. 20, 2005) ("*Nicor Gas 2005*"); NS-PGL Reply Br. at 30. Similarly, in the 1995 Nicor rate case, the Commission indicated that the pension balance had gone from negative to positive since the utility's 1987 rate case without any pension plan contributions. *In re Northern Illinois Gas Co.*, ICC Docket No. 95-0219, 1996 Ill. PUC Lexis 204, *20 (Order April 3, 1996) ("*Nicor Gas 1996*"); NS-PGL Reply Br. at 30. Both Orders are inconsistent with the facts of this case.

The more appropriate model is the Commission's Order in *In re Central Illinois Light Co.*, ICC Docket No. 94-0040 (Order Dec. 12, 1994) ("*CILCO*"). As discussed in *Nicor Gas 1996*, the Commission in *CILCO* approved the inclusion of a pension asset in rate base on the grounds that the utility, unlike Nicor Gas, had made pension plan contributions and the inclusion was not a contested issue. *Nicor Gas 1996* at *22; NS-PGL Reply Br. at 30. Thus, the *Nicor Gas 2005* and *Nicor Gas 1996* Orders do not support Staff's and GCI's proposed adjustments, because the relevant facts as relied upon by the Commission are not the same, and the 1994 *CILCO* case supports inclusion.

Accordingly, the OPEB liabilities adjustments should not be made, or alternatively, they should be made only if Peoples Gas' net pension asset of $110,000,000 and North Shore's net pension liability of $24,000 are included in the calculation of the Utilities' rate bases. *E.g.*, Kallas Reb., NS-PGL Ex. LK-2.0 REV, at 13. Finally, however, further in the alternative, if the

OPEB liabilities are to be deducted, and the Commission determines not to reflect the Peoples Gas pension asset and the North Shore pension liability in calculating rate base, then the Commission should maintain its incorporation of Peoples Gas' contributions of $15,278,614 and North Shore's contributions of $1,862,247 to the pension plan in the calculation of their rate bases, as recommended by the Proposed Order. The Proposed Order should be revised as provided for in Exception No. 7 in the NS-PGL Exceptions.

I. <u>Overall Conclusion on Rate Base</u>

<u>Exception No. 8</u>

Pages 36-38 of the Proposed Order set forth a total recommended figure of $1,189,846,000 for Peoples Gas' rate base and the figures for the high level components thereof. Those pages should be revised to reflect North Shore's and Peoples Gas' Exceptions on rate base issues discussed above and the derivative impacts thereof. Also, for the sake of completeness, the Proposed Order should be revised by adding a parallel summary of North Shore's rate base. The Appendices to the Proposed Order also should be revised accordingly. See Exception No. 8 in the NS-PGL Exceptions.

III. <u>OPERATING EXPENSES</u>

B.5.i. Uncontested Issues – Administrative & <u>General Expenses – Rate Case Expenses</u>

<u>Exception No. 9</u>

Page 45 of the Proposed Order states in part that the Utilities "further abandoned their proposal to include the unamortized portion [of rate case expenses] in rate base...." Because, as the preceding portion of the same sentence in the Proposed Order indicates, the Utilities withdrew this proposal in order to narrow the issues, and because the issue may arise in future cases, the Utilities are concerned that the phrase "further abandoned" might be misunderstood in the future to constitute a position on the merits. Accordingly, the Utilities propose to change "further abandon" to "withdrew", as set forth in Exception No. 9 in the NS-PGL Exceptions.

C.3.b. Contested Issues – Administrative & <u>General Expenses – Incentive Compensation Expenses</u>

<u>Exception No. 10</u>

While the Proposed Order correctly allows the Utilities to recover certain minimum amounts of incentive compensation costs and expenses, it errs in accepting GCI's and Staff's erroneous and unreasonable proposals to disallow other costs associated with incentive compensation. *See* Proposed Order at 66-67.

The Commission should approve all of the incentive compensation program costs and expenses included in the Utilities' proposed revenue requirements. No witness challenged the testimony of the Utilities' witness, Mr. Hoover, that these costs and expenses are needed in order to attract and retain high-quality employees and in sufficient numbers. *E.g.,* Hoover Reb., NS-PGL Ex. JCH-1.0, at 3; NS-PGL Init. Br. at 47; NS-PGL Reply Br. at 43. No witness challenged Mr. Hoover's testimony that these costs and expenses are prudent and reasonable, or that these costs benefit a utility's customers by "maintaining and improving the productivity and quality of work". Hoover Reb., NS-PGL Ex. JCH-1.0, at 3-4; NS-PGL Init. Br. at 47-48; NS-PGL Reply Br. at 44. Also, no witness disputed that the Utilities' incentive compensation programs resulted in a reduction of O&M expenses below target levels. Hoover / Volante Sur., NS-PGL Ex. JCH/FLV-2.0, at 6; NS-PGL Init. Br. at 48; NS-PGL Reply Br. at 46. Moreover, as detailed in the Utilities' Initial Brief at page 48, the Commission repeatedly has recognized that incentive compensation programs that reward employees for reducing operating costs benefit customers. GCI's and Staff's proposed disallowances thus contravene the established principle that rates "must allow the utility to recover costs prudently and reasonably incurred." *Citizens*

Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d 111, 121 (1995). The Proposed Order concludes in part that: "While these plans may indeed be necessary 'to attract and retain a qualified workforce' this is not reason enough to allow the expense." Proposed Order at 66. The Utilities respectfully submit that there is no valid basis for "disqualifying" attracting and retaining a qualified work force as a grounds for approving prudent, reasonable, and needed costs and expenses, and that to do so is not consistent with the principle recognized in the *Citizens* case cited above.

The specifics of the incentive compensation programs at issue, and why the entire amounts and, in many instances, alternative amounts should be approved under each specific program are discussed in detail in the Utilities' Initial Brief at 47–53 and their Reply Brief at 43-47. Accordingly, the Proposed Order should be revised as set forth in Exception No. 10 in the NS-PGL Exceptions, approving the entire amounts of the costs and expenses at issue, or, alternatively, approving specific additional amounts. Should the Commission not approve the entire or additional amounts, however, it should approve the minimum amounts approved by the Proposed Order.

I. Overall Conclusion on Operating Expense Statements

Exception No. 11

Pages 71 to 75 of the Proposed Order set forth total recommended operating expenses figures of $364,456,000 as to Peoples Gas and $48,629,000 as to North Shore, plus figures for the respective high level components thereof. Those pages should be revised to reflect North Shore's and Peoples Gas' Exceptions on operating expenses issues discussed above and the derivative impacts thereof (as well as the derivative impacts of the Utilities' Exceptions on rate base issues discussed earlier herein and of the Utilities' Exceptions on rate of return issues discussed below). The Appendices to the Proposed Order also should be revised accordingly. See Exception No. 11 in the NS-PGL Exceptions.

IV. RATE OF RETURN

Exception No. 12

Pages 77 to 91 of the Proposed Order present the cost of equity positions and arguments of the Utilities, Staff and CUB/City. The Utilities propose a number of corrections to these pages. These corrections are needed to ensure that the parties' positions are stated accurately.

Exception No. 13

Pages 91 to 95 of the Proposed Order present the ALJs' proposed Commission Analysis and Conclusions on the Utilities' equity. The Utilities address their exceptions to this section of the Proposed Order in an integrated fashion.

The Utilities have requested that their cost of equity be set at 11.06%. The Utilities urge the Commission to consider the unique importance of its cost of equity decisions in these particular rate cases, which are the first for the Utilities since 1995 and their first since Integrys Energy Group, Inc., became their ultimate parent company earlier this year. The Commission's decisions will send a message to the financial community concerning the degree to which the Commission will support the financial strength of the Utilities under Integrys' new ownership and management.

To the Utilities' great concern, the Proposed Order adopts in whole the Staff position on the Utilities' costs of equity, 9.70% for Peoples Gas and 9.50% for North Shore. If adopted by the Commission, these would be the lowest returns it has set for a gas utility in over 30 years. Moul Sur., NS-PGL Ex. PRM - 3.0, at 12. Such returns would send a very negative signal to Integrys and the financial markets on the degree to which the Commission will support the

Utilities' financial strength. They would also signal to the markets that utility returns in Illinois will be among the lowest in the nation, with the result that capital available for utility investment will be encouraged to go elsewhere. Moul, Tr. 1047:21 – 1048:7.

The Proposed Order's rejection of CUB/City's result-driven approach and even lower returns (below 8% if Riders VBA and UBA are approved) is entirely appropriate. But its wholesale rejection of the Utilities' position is not. Notably, the Proposed Order does not expressly conclude that the Utilities' analyses have such serious shortcomings that they should not be considered in establishing the Utilities' costs of equity. To the contrary, the Proposed Order notes the close proximity of Staff's and the Utilities' unadjusted DCF and CAPM average results. Proposed Order at 92 and 93.

Consistent with its approach in recent rate cases, the Commission should base the Utilities' cost of equity on the valid financial model results before it. *Central Illinois Light Co. d/b/a AmerenCILCO, et al.,* Docket Nos. 06-0070, 06-0071, 06-0072 (Cons.), at 148 (Order, Nov. 21, 2006) ("Ameren Order"); *Commonwealth Edison Co.*, Docket No. 05-0597, at 155 (Order, July 26, 2006) ("ComEd Order"). Attachment 1 hereto presents a table of the Staff and Utility cost of equity model results. As discussed below, the Proposed Order's recommended adoption of the Staff position for each of the Utilities is, in three respects, contrary to controlling law and/or not supported by substantial evidence.

First, the Commission should disregard Staff's DCF results, which vary too widely and include rates of return that approach and even fall below the utility cost of debt. There is something clearly amiss with Staff's DCF analysis and it is not a credible basis on which to base the Utilities' costs of equity. If the Staff DCF result is therefore disregarded, that would leave the Staff's CAPM result as the sole remaining "valid" financial model result under the Proposed

Order. This would result in an unadjusted cost of equity for the Utilities of 11.34%. However, as shown in Attachment 1, if the Commission considered the Utilities' DCF and CAPM results, then the average of those results with Staff's CAPM result would yield an unadjusted market-based cost of equity of 10.38%.

Second, the Proposed Order reflects a misunderstanding of the Utilities' proposed financial leverage adjustment, which is not a "market-to-book" adjustment of the type previously rejected by the Commission, but rather an adjustment required to ensure that the Utilities' cost of equity reflects the risk of their book value capital structures and to provide them with an opportunity to earn its authorized return on equity. If the financial leverage adjustment is made to the Utilities' DCF and CAPM results and those are averaged with Staff's CAPM result, the Utilities' cost of equity would be 10.91%.

Third, the record does not support Staff's specific "financial risk" adjustments based on the hypothetical forward-looking, stand-alone credit ratings developed by Staff. The adjustments are not appropriate because Staff did not provide a basis for focusing exclusively on potential differences between the Utilities and the proxy group in financial risk as reflected by credit ratings, without considering the existence of other, potentially offsetting risk differentials. In addition, as in the recent Ameren rate case, there is too much disparity between the Utility's actual credit ratings and Staff's hypothetical credit ratings. Indeed, the disparity in this case is <u>precisely</u> the disparity found unreasonable in Ameren.

<u>The Unique Importance of the Commission's Cost of Equity Decisions</u>

The Commission has historically set utility rates at the level required to maintain the "financial integrity" of the utility, which the Commission has defined 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." *Illinois Power Co.*, 51 P.U.R.4th 39, 54 (Order January 12, 1983). Because these are the Utilities' first rate cases since 1995, and the first since Integrys acquired them, the Commission's decisions in this case will send a strong message to Integrys and the financial markets regarding the degree to which the Commission will support the Utilities' financial strength and their operation under Integrys' new ownership and management.

The Commission approved Integrys' acquisition of Peoples Energy Corporation in February of this year. *In re WPS Resources Corp., et al.*, ICC Docket No. 06-0540 (Order Feb. 7, 2007) ("Integrys Order"). The undisputed evidence in that proceeding showed that the customers of Peoples Gas and North Shore will benefit significantly from the acquisition:

- Integrys will provide the Utilities with a larger and stronger financial platform to support improvements to, and maintenance of, their respective distribution systems for the benefit of their customers. *Id.* at 9.

- Integrys will bring industry best practices and operational excellence to the Utilities' operations. *Id.* Integrys' commitment to industry best practices and operational excellence will ensure a high quality of service is provided to the Utilities' customers and enhance customer satisfaction. *Id.* at 11. Integrys has a long history of being highly rated by customers and it intends to deliver the same high level of service to the Utilities' customers. *Id.*

- The acquisition will produce significant savings for customers over time through the integration of the Utilities' administrative, managerial, and overhead functions into the Integrys system, and the achievement of economies of scale associated with the larger and more diverse enterprise created by the acquisition. *Id.* at 9. These efficiencies and economies of scale will enhance the Utilities' service. *Id.* at 11.

- Integrys is committed to maintaining and enhancing the service and support that the Utilities provide to the communities they serve. Integrys brings a long and strong tradition of providing excellent service and support through civic, community, and philanthropic efforts and this tradition will continue. *Id.* at 10.

- The acquisition delayed the Utilities' rate cases and therefore deferred their needed rate increases by a year. Integrys also agreed to forego any further general rate increases until at least 2010. *Id.*

- Integrys has a strong record of maintaining the financial strength of its regulated subsidiaries and operating them reliably, efficiently and safely. *Id.* at 11.

In order to deliver on these commitments, Integrys proposed and agreed to a number of conditions related to maintaining capital, operation and maintenance expenditures, and improving various aspects of the Utilities' service, including improvements associated with service quality, infrastructure, union employment, and energy efficiency. *Id.* at 11-14, 23-26; *see also* PGL Ex. LTB-1.6. On the basis of Integrys' commitments, the Commission "solidly" found that the acquisition, ownership and operation of the Utilities by Integrys satisfied the criterion of Section 7-204(1) of the Public Utilities Act, 220 ILCS 5/7-204(1). Integrys Order at 26.

In the months since the acquisition, Integrys has worked diligently to achieve an efficient and effective transition of the Utilities into Integrys' management and systems. The record documents Integrys' full compliance with those conditions that affect the Utilities' rates. Borgard Dir., PGL Ex. LTB-1.0, at 30-31; Doerk Dir., PGL Ex. ED-1.0, at 21-22; Fiorella Dir., PGL Ex. SF-1.0, at 5, 19, 28; Rukis Dir., PGL Ex. IR-1.0; Schott Dir., PGL Ex. JFS-1.0, at 5; Zack Dir., PGL Ex. TZ-1.0, at 25, 26, 27–28.

Juxtaposed against this record of strong progress, a Commission decision setting the Utilities' costs of equity at levels lower than the Commission has set for any other gas utility in over 30 years would send a very negative message to Integrys and the financial markets, a message that will almost certainly reduce the Utilities' financial strength and lead to higher financing costs in the future. Indeed, the Utilities' cost of equity witness believes that "the financial community would be extremely concerned" if the Commission set the Utilities' rates of returns at the levels proposed by Staff. Moul Reb., NS-PGL Ex. PRM-2.0, at 2.

Throughout this proceeding, Staff has failed to explain how rates of return of 9.50% and 9.70% can be appropriate for the Utilities, when the Commission awarded another Illinois natural gas company a 10.51% ROE two years ago. *In re Northern Illinois Gas Co.*, ICC Docket No. 04-0779, at 88 (Order Sept. 20, 2005). Nor has Staff explained how its position can be correct when the recent ROEs authorized other gas utilities throughout the country are generally in the range of 10.5% to 11.0%. Moul Reb., NS-PGL Ex. PRM-2.0, at 3-4. Published evaluations and forecasts by such analysts as Lehman Brothers and Value Line strongly support Mr. Moul's opinion of investor expectations. *Id.*, at 4-5,

Rather, Staff argues that the recently authorized returns of other gas utilities are irrelevant and should be ignored. To be clear, the Utilities are not arguing that their returns should be based on the authorized returns of other utilities. Rather, such returns collectively provide a guidepost against which to compare the analyses and positions taken by Staff and the other parties. Such returns are an appropriate guidepost because they form the basis of real expectations by the real investors who set the prices of the Utilities' equity. Moul, Tr. 1043:2-14.

Against this guidepost, Staff's position is far below the range of expected returns and at the extreme low end of the range of all recent returns.[3] If Staff's position is to be believed, the gas utilities serving the Chicago area have the lowest risk and lowest cost of equity of any gas utility in Illinois, and among the very lowest in the country.[4]

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[3] Contrary to the Proposed Order (at 89), Staff's proposed costs of equity of 9.50% and 9.70% are obviously not "as close to" the 10.49% average U.S. gas utility return as the Utilities' request of 11.06%. The Utilities' request is 57 basis points above the average. Staff's position for Peoples Gas is 79 basis points below the average and its position for North Shore is 99 basis points lower than the average.

[4] Indeed, adoption of the Staff position would set the Utilities' returns at levels similar to that of CenterPoint Energy Arkla ("CEA"), the utility with the lowest return (9.45%) in Mr. Moul's sample of 2006 returns. CEA's return reflects an $11.5 million rate decrease, and punishment for deficient accounting and recordkeeping practices and inadequate customer service. NS-PGL Ex. PRM-2.2, at p. 4. Staff has failed to explain why the Utilities deserve such punitive ROEs right after Integrys acquired them.

The costs of equity proposed by Staff and the ALJs are also significantly lower than the most recent rates of return authorized for Integrys' regulated subsidiaries. In mid-2006, the Michigan Public Service Commission approved a settlement authorizing Upper Peninsula Power Company an ROE of **10.75%**. MPSC Case No. U-14745 (Opinion and Order June 27, 2006). In February of this year, the Public Service Commission of Wisconsin set Wisconsin Public Service Corporation's ROE at **10.9%**. PSCW Docket 6690-UR-118 (Final Decision Feb. 11, 2007). Earlier this month, the Michigan Public Service Commission approved a settlement authorizing Wisconsin Public Service Corporation an ROE of **10.6%**. MPSC Case No. U-15352 (Dec. 4, 2007).

For this Commission to set the Utilities' ROEs at levels some 100 basis points below the level generally received by other gas utilities and Integrys' other regulated subsidiaries would send a strong signal to the financial market that the Commission will not support the financial strength of Integrys' Illinois regulated subsidiaries at the same levels as Integrys' regulated subsidiaries are supported in other states. The reaction will likely be negative and will not benefit the Utilities' customers.

Staff's DCF Result Should Be Rejected

Mechanistically adhering to its financial model results, Staff has throughout this proceeding refused to consider even the possibility that its extremely low cost of equity results reflect problems in Staff's models, data, or both. Such complacency hides fundamental problems that, intentionally or not, skew Staff's results to the very bottom of the range of recent gas utility ROEs. In adopting the Staff position without any correction or adjustment, the Proposed Order compounds these flaws.

The Proposed Order relies heavily on the premise that only 11 basis points separate the Utility and Staff DCF and CAPM results. This relationship between averages is coincidental and without meaning. The spread between Staff's average DCF (8.23%) and CAPM (11.34%) results for the proxy group is 311 basis points. Moul Sur., NS-PGL Ex. PRM-3.0, at 11. This disparity is simply too wide to provide a meaningful average. As Mr. Moul testified, "missing the target by ten feet to the right on the first try, followed by a miss of ten feet to the left on the second try, does not equal an average 'bulls eye.'" *Id.*, at 8.

The root of these problematic results lies with Staff's use of stock prices and dividend data from a single day over seven months ago, April 25, 2007. Using that snapshot of data, which by Staff's own logic became outdated and irrelevant a day later,[5] Staff's DCF model generated costs of equity below 9% for seven of the nine companies in the utility proxy group, including 5.91% for Nicor Gas, a gas utility whose cost of equity the Commission found to be 10.51% two years ago. Moul Reb., NS-PGL Ex. PRM 2.0, at 12-13. Results approaching and even falling below utility cost of debt (A-rated utility debt yield is just over 6%, Moul Reb., NS-PGL Ex. PRM-2.0, at 12) render Staff's DCF results an inappropriate basis on which to set the Utilities' costs of equity.

Staff concedes that its DCF result for Nicor Gas is more than one standard deviation below the mean of its DCF results, but argues that if the Nicor Gas DCF result is disregarded, its DCF result for Atmos Energy Corp. (9.75%) should also be disregarded because it is more than

[5] The problems with Staff's use of stock price and dividend data from a single day some six months before the hearing and eight or nine months before the Commission's decision are fully treated in the Utilities' Initial Brief, and will not be repeated here. NS-PGL Init. Br., at 66-70. Suffice it to say that the staleness of Staff's data prejudiced the Utilities because stock market volatility, utility interest rates and utility stock prices all rose after April 25, 2007. Had Ms. Kight-Garlisch updated her DCF model, her result would have increased by almost <u>70 basis points</u>. Moul Sur., NS-PGL Ex. PRM-3.0, at 5. A full update of Staff's financial models would have undoubtedly increased Staff's results significantly.

one standard deviation above the mean. Kight-Garlisch Sur., Staff Ex. 18.0, at 7. But removing these offending results would not cure the problems in Staff's DCF model that created the offending results. It is the fact of these results, not their inclusion or exclusion from the sample, that renders Staff DCF results unusable in this case.

The Commission recently dealt with a similar problem with a different aspect of a Staff cost of equity analysis. In the recent Ameren rate case, the Commission was troubled by the results of Staff's financial risk analysis, finding that "something is amiss in this particular situation. In the Commission's view, there is simply too wide a disparity between CILCO's, CIPS', and IP's actual credit ratings and what Staff projects will be the financial strength of CILCO, CIPS, and IP after this rate proceeding." Ameren Order at 146.

The Commission should be no less troubled by the wide disparity between Staff's DCF and CAPM results, and DCF results that approach and even fall below the utility cost of debt. Such results signal that there is something amiss with Staff's DCF model and it should not be used to set the Utilities' cost of equity in this case. For these reasons, the Commission should disregard Staff's DCF result.[6]

If the Commission does so, it must consider what "unadjusted" cost of equity on which to base its decision. In the Ameren and ComEd rate cases, the Commission rejected the utility's ROE proposal and used the remaining proposals to set the utility's cost of equity. Ameren Order at 148; ComEd Order at 155. Under the Proposed Order, the only remaining "valid" unadjusted result is Staff's CAPM result of 11.34%, which is higher than the Utilities' requested return of 11.06%. The Commission should take the Utilities' financial model results into consideration

[6] Unlike its DCF result, Staff's CAPM result of 11.34% is well within the range of recent gas utility returns, and therefore does not lack facial credibility. Moul Reb., NS-PGL Ex. PRM-2.0, at 4.

because they are in a range, 9.01% to 11.25% (unadjusted), that is comparable to Staff's unadjusted CAPM result. If the Commission did so, the remaining model results would be Staff's CAPM result and the Utilities' DCF, CAPM and Risk Premium ("RP") model results.

The RP model determines cost of equity by determining the market price difference between the rate of return on debt capital and the rate of return on common equity. In this case, the Utilities' cost of equity witness calculated an 11.44% cost of equity for the Utilities using well-recognized sources for data on historical, current, and forecasted utility bond and common equity yields. Moul Dir., PGL Ex. PRM-1.0, at 31-36; PGL Ex. PRM-1.13F. This result is within 10 basis points of Staff's CAPM result.

The Utilities acknowledge that the Commission has in the past rejected the RP model as a valid basis on which to set utility costs of equity. *E.g., Central Illinois Light Co.*, Docket No. 02-0837 (Order, Oct. 17, 2003). However, the Commission accepted an analyst's cost of equity recommendation in the Commonwealth Edison rate case that was an average of the analyst's DCF, CAPM, and RP results. ComEd Order at 150. That order contains no rebuttal to IIEC's argument supporting the RP model:

> The risk premium model is based on the principle that investors require a higher return to assume a greater risk. Common equity is viewed as having greater risk than corporate bonds. Under the RP model, the risk premium representing the greater risk of equity in comparison to bonds may be calculated in two different ways: (a) as the difference between the required return on utility common equity investments and a U.S. Treasury bond; and (b) as the difference between the return on equity approved for utilities by regulatory commissions and return on contemporary utility bonds. IIEC says its witness, Mr. Gorman, used both methods and developed an RP return on common equity recommendation of 10.2%, which was considered along with his DCF and CAPM model results in determining his final ROE recommendation.

Id. at 152. After finding the utility's ROE recommendation to be "excessively high," the Commission proceeded to set the cost of equity based on Staff's and IIEC's recommendations. *Id.* at 155. In doing so, the Commission relied in part on an RP model result despite its past rejection of the model. The Commission should similarly consider including Mr. Moul's RP model result among the results on which the Utilities' costs of equity are based.

If, however, the Commission disregards the Utilities' RP model result, then, as shown on Attachment 1, the Utilities' costs of equity based on the average of the Staff CAPM result and the Utilities' DCF and CAPM results, and unadjusted for financial risk or flotation costs, would be 10.38%.

The Utilities' "Financial Leverage" Adjustment Is Required to Ensure <u>that the Utilities Have an Opportunity to Earn Their Authorized ROEs</u>

The Utilities' cost of capital witness, Mr. Moul, proposes a "financial leverage" adjustment to the market-based results of the financial models to reflect the higher risk of the utility's book value capital structure used for ratemaking purposes. Mr. Moul found that his DCF result must be increased by 52 basis points and his CAPM result by 106 basis points to ensure that the Utilities have an opportunity to earn their authorized ROEs. Moul Dir., PGL Ex. PRM-1.0 REV, at 25-28; PGL Ex. PRM-1.13C.

The Proposed Order reflects a misunderstanding of Mr. Moul's financial leverage adjustment as a "market-to-book" adjustment of the type rejected by this Commission in the past. *E.g.*, Ameren Order at 141 (rejecting proposal to set utility ROE at level to maintain market-to-book ratio <u>above</u> 1.0); ComEd Order at 154 (rejecting proposal to set utility ROE at level to maintain market-to-book ratio <u>at</u> 1.0). The Proposed Order states that 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." Proposed Order, at 86. As previously explained by the Utilities, that is incorrect. NS-PGL Reply Br. at 53-54.[7] The Proposed Order describes the market-to-book adjustment proposed by other utilities in the past and rejected by the Commission, not the financial leverage adjustment proposed by Mr. Moul.

Unlike the market-to-book adjustments previously rejected by the Commission, Mr. Moul's financial leverage adjustment is not intended to maintain a certain market-to-book ratio. His adjustment is based on the "Modigliani-Miller" theorem that there is a direct relationship between a firm's capital structure and its cost of equity. "[A]s the borrowing of a firm increases, the required return on stockholders' equity also increases." Moul Dir., PGL Ex. REV PRM-1.0, at 27. This is the same principle on which Staff's "financial risk" adjustment is based. Kight-Garlisch Reb., Staff Ex. 18.0, at 4. The Commission has accepted the theoretical basis of Staff's financial risk adjustment even when rejecting Staff's specific adjustments. Ameren Order at 146.

It is undisputed that market-based returns derived from the financial models are based on capital structures that contain more equity and less risk than the book value capital structures containing less equity and more risk that are used for ratemaking purposes. In this case, the market value capital structure of the proxy group contained 67.52% equity, while its book value equity ratio was only 53.98%. PGL Ex. PRM-1.13C, at 14.

Applying a market-based return on equity to a book value capital structure is by definition a mismatch of risk and return, or financial leverage. Absent an adjustment to correct this mismatch, all other things equal <u>the utility will not earn enough to achieve its authorized return</u>. Moul Dir., PGL Ex. PRM-1.0 REV, at 25. This has nothing to do with changing the

[7] The ALJs may have confused by the repeated references by Staff and CUB/City to Mr. Moul's financial leverage adjustment as a "market-to-book" adjustment. Staff Init. Br. at 59, 61, 64, 65 (twice), 68; CUB-City Init. Br. at 28, 30, 32, 33, 41, 42, 43; CUB-City Reply Br. at 28-30.

manner in which the Utilities' risk is measured. Staff Init. Br. at 65. It has everything to do with ensuring that the risk reflected by the Utilities' authorized rates of return on equity accurately reflects the risk associated with the Utilities' book value capital structure. Mr. Moul's financial leverage adjustment ensures that the authorized return accurately reflects the risk associated with a book value capital structure.

The Proposed Order rejects Mr. Moul's financial leverage adjustment for the same reasons that the Commission has rejected market-to-book adjustments; namely, that the Commission has been applying market-based returns derived from financial models to utility book value capital structures for years and the sky has not fallen. Proposed Order at p. 93. The Proposed Order asserts that if Mr. Moul was correct, then the market values of common equity for utilities would not have remained above book value for all of these years. *Id.*

This argument finds no basis in the record. To the contrary, the record is very clear that there are many factors <u>other than</u> a utility's authorized rate of return that affect the market value of its stock, including general market sentiment, expectations regarding business reorganizations, the market value of the utility's assets, and changes in interest rates. Moul Reb., NS-PGL Reb. Ex. PRM-2.0 REV, at 19. As Staff admits: "There are many utility ratemaking practices (e.g., deferred taxes and depreciation) that could result in a utility's market value exceeding its book value." Kight-Garlisch Reb., Staff Ex. 18.0, at 19. Staff also admits that "the authorized return for [each utility in Mr. Thomas' market-to-book analysis] is not the only factor influencing its earnings." *Id.* These Staff admissions flatly contradict its position that a market-to-book ratio of greater than one precludes Mr. Moul's financial leverage adjustment. Kight-Garlisch Dir., Staff Ex. 6.0, at 33-35.[8]

For these reasons, the fact that utility stock values have been historically higher than book value does not refute the need for Mr. Moul's financial leverage adjustment in order to ensure that the utility has an opportunity to earn its authorized return. The Proposed Order's justification for rejecting the adjustment is speculative and therefore inadequate. Mr. Moul's financial leverage adjustment is based on sound financial theory and the undisputed fact that the financial models' market-based returns reflect lower risk than the proxy group's book value capital structures. Indeed, all other things equal, <u>the adjustment must be applied or else by definition the utility will not earn its authorized return</u>.

For these reasons, the Commission must apply the financial leverage adjustment to a market-based return before applying it to the Utilities' book value capital structures in order to provide the Utilities with the opportunity to earn their authorized returns, an opportunity to which they are entitled under Illinois law. *Illinois Bell Tel. Co. v. Illinois Commerce Comm'n*, 414 Ill. 275, 286 (1953); *Citizens Utilities Co. of Ill. v. Illinois Commerce Comm'n*, 153 Ill. App. 3d 28, 30 (1987).

As shown in Appendix A, the financial leverage adjustments to Mr. Moul's DCF and CAPM results are 52 and 106 basis points, respectively. Averaging these adjusted results with Staff's CAPM result results in a cost of equity of 10.91%, exclusive of flotation costs.

[8] Staff argues that because a utility <u>can</u> receive earnings from sources other than its regulated services, the Commission would set in motion "a never ending upward spiral" of returns with the financial leverage adjustment. Kight-Garlisch Dir., Staff Ex. 6.0, at 35-36. This assumes, of course, that the Utilities earn a significant amount of earnings from non-regulated activities, an assumption that Staff did not even attempt to establish. Staff's "R_{other}" argument is a red herring.

The Record Does Not Support Staff's Specific "Financial Risk" Adjustments

The Proposed Order adopted Staff's "financial risk" adjustments to the Utilities' market-based returns, reducing Staff's already low result of 9.79% by 9 basis points for Peoples Gas and 29 basis points for North Shore. Kight-Garlisch Dir., Staff Ex. 6.0, at 16. These adjustments represent Staff's attempt to comply with Section 9-230 of the Public Utilities Act, which requires the Commission to ensure that a utility's authorized rate of return does not reflect the increased risk of non-regulated activities. 220 ILCS 5/9-230. Staff's financial risk adjustment involves the creation of a hypothetical forward-looking "stand-alone" credit rating for a utility in a holding company system based on the application of the published "benchmark" financial ratios used by the Standard & Poors' ("S&P") credit rating agency. Staff then compares this hypothetical credit rating to the average credit rating of the proxy group and calculates an adjustment to the utility's cost of equity for the difference. Kight-Garlisch Dir., Staff Ex. 6.0, at 16-22.

The Utilities do not challenge the premise of Staff's financial risk adjustment, but they do challenge Staff's specific adjustments because they are not supported by the weight of the evidence. The adjustments fail this test for three reasons.

First, Staff's adjustment assumes that the Utilities' credit ratings are affected by Integrys' non-regulated activities, but the credit ratings of the proxy group are not. Staff did not support this assumption. To the contrary, Ms. Kight-Garlisch appears to have recognized that some of the companies in the utility proxy group are affected by "increased operating risk at the parent company." Staff Ex. 6.0, Sched. 6.1. She adjusted these companies' S&P Business Profile scores, but did not adjust their credit ratings. Had she done so, these companies' credit ratings would have been enhanced, and the differential between the proxy group's average credit rating and the Utilities' hypothetical stand-alone credit ratings would have been smaller than she portrayed it to be. Staff's analysis is faulty, and the Proposed Order's conclusion that "Staff has been able to isolate [the Utilities'] financial risk" compared to the proxy group must be rejected.

Second, even if the Utilities' "stand alone" financial risk was lower than the proxy group's average financial risk, Staff failed to demonstrate that this difference required an adjustment to the proxy group's collective cost of equity. By its very nature, a proxy group cannot be precisely the same as the utility being analyzed. Mr. Moul conducted an exhaustive analysis of natural gas utilities to populate his proxy group using a plethora of financial parameters. Moul Dir., PGL Ex. PRM-1.0, at 7-14. Some of the risk factors of the Utilities were higher than the proxy group and some were lower, but Mr. Moul concluded that, "On balance, the risk factors average out, indicating that the cost of equity for the utility sample would provide a reasonable basis for measuring the [Utilities'] cost of equity." Moul Dir., PGL Ex. PRM-1.0 REV, at 14. <u>Neither Staff nor CUB/City challenged Mr. Moul's conclusion</u>. Accordingly, even if Staff's analysis of comparative credit ratings was valid, it is insufficient to support an adjustment of the Utilities' market-based costs of equity because Staff did not demonstrate the <u>absence</u> of differences in other risk factors would offset the impact of the Utilities hypothetically having higher credit ratings than the proxy group's average credit rating.

In other words, Staff has failed to confirm that there are no risk differentials that offset that "financial risk" difference. To isolate a single risk factor, find differences, and make adjustments based on those differences without considering whether offsetting differences and adjustments exist, is arbitrary and capricious. *E.g., Pollacheck v. Department of Prof. Reg.,* 367 Ill. App .3d 331, 342 (2006) (agency acts arbitrarily and capriciously if it fails to consider an important aspect of the problem); *C.J. v. Department of Mental Health and Developmental Disabilities,* 296 Ill. App. 3d 17, 31 (1998) (same); *see also Exchange Nat. Bank of Chicago v.*

Air Ill., Inc., 167 Ill. App. 3d 1081, 1092 (1988) ("Further, defendant's tendered instruction isolates one of the several factors to be considered in calculating damages and, therefore, was improper for emphasizing that factor over others.").

Third, in the Ameren rate case the Commission rejected Staff's downward adjustment of three utilities' costs of equity. The Commission, finding "something is amiss," determined that "there is simply too wide a disparity between [the utilities'] actual credit ratings and what Staff projects will be the financial strength of [the utilities] after this rate proceeding." Ameren Order at 146. The Commission found that "the cost of capital depends to some extent on factors that produce the actual rather than implied credit rating." *Id.* The unreasonably wide disparities between the utilities' actual and hypothetical credit ratings in *Ameren* were as follows:

<u>Utility</u>	<u>Actual</u>	<u>Hypothetical</u>
CILCO	A-	AA-
CIPS	A-	AA
IP	BBB+	A+

Id. The actual and hypothetical credit ratings of the Utilities in this case are as follows:

<u>Utility</u>	<u>Actual</u>	<u>Hypothetical</u>
PGL	A-	AA-
NS	A-	AA

Kight-Garlisch Dir., Staff Ex. 6.0, at 18-21.

Thus, in this case Staff proposes to adjust the Utilities' market-based returns for financial risk based on precisely the same disparities in credit ratings that the Commission found "simply too wide" for CILCO and CIPS in the Ameren rate case just one year ago. Just like CILCO and CIPS, the Utilities' cost of capital "depends to some extent on factors that produce the actual rather than implied credit rating." Ameren Order at 146. As with CILCO and CIPS, the Commission should have the view that "these same types of factors cause [the Utilities'] actual credit ratings to be lower than [their] 'implied' credit ratings." *Id.* As in *Ameren,* "the record does not support adopting [Staff's] specific downward adjustments in this proceeding. *Id.*

<u>Conclusion on Cost of Common Equity</u>

For these reasons, the Commission should (1) reject Staff's DCF result and base the Utilities' cost of equity on an average of Staff's CAPM result with the Utilities' DCF and CAPM results, (2) accept the Utilities' proposed "financial leverage" adjustment to ensure that the authorized rate of return on equity is consistent with the risk associated with the Utilities' book value capital structures, and (3) reject Staff's specific "financial risk" adjustments in this case due to the unreasonably wide disparity between the Utilities actual credit ratings and hypothetical forward-looking stand-alone credit ratings developed by Staff. If these adjustments are made to the Proposed Order, then the Utilities' cost of equity exclusive of flotation costs would be 10.91%. The Utilities' request for a cost of equity of 11.06% is therefore reasonable. See Exception No. 13 in the NS-PGL Exceptions.

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

<u>Exception No. 14</u>

The Utilities weighted average costs of capital should be modified to incorporate a cost of equity of 11.06%, consistent with the cost of equity discussion above. Peoples Gas' approved weighted average cost of capital should be 8.24%, including 4.67% cost of long-term debt and 11.06% return on common equity. North Shore's approved weighted average cost of capital should be 8.56%, including 5.39% cost of long-term debt and 11.06% return on common equity. See Exception No. 14 in the NS-PGL Exceptions.

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

Exception No. 15

The Proposed Order at page 113 requires a clarification of the cost of capitalized cushion gas injections that will be included in Peoples Gas' rate base. The Proposed Order concludes at page 101 that, "[I]n total, the capitalized injections since Peoples Gas' last rate case amount to 7.88 MMDth of gas". Proposed Order at 101. The Proposed Order further finds at page 113, that "Peoples Gas capitalized an additional 7.88 MMDth of injections as cushion gas into Manlove Field, at a cost of $39,019,000". The Proposed Order's findings support inclusion of that $39,019,000 in rate base, which is the only finding consistent with the evidence. In the final sentence of the same paragraph, the Proposed Order states that "$34,857,000" will be included in the rate base. Peoples Gas believes that to be a typographical error. Peoples Gas' Exception No. 15 provides that the correct amount to be included in rate base is $39,019,000.

VI. WEATHER NORMALIZATION

Exception No. 16

The Proposed Order at 117-119 recommends use of a particular 12 year period for weather normalization purposes. The Utilities continue to believe that the evidence shows that a 10 year period is most appropriate and, therefore, should be used.

The rates for delivery of gas depend in substantial part on the amount of gas each customer uses. The Utilities' total sendout depends directly on the temperature in the service territory. Grace Reb., PGL/NS Ex. 2.0, at 25. This is measured as heating degree days, or "HDDs". Takle Dir., PGL Ex. EST-1.0, at 7; Takle Dir., NS Ex. EST-1.0, at 7. Because the Proposed Order rejects both of the Utilities' proposed riders that would remove weather variability from determining the Utilities' revenues (Riders VBA and WNA, discussed later herein), it is particularly important that the Utilities' rates build in an accurate prediction, or assumption, of what the HDDs will be during the years the approved rates are in effect. The Proposed Order correctly finds that basing the HDDs prediction on thirty years of weather data would be inaccurate, and therefore undesirable. Proposed Order at 118.

The Utilities proposed using the most recent ten years of data at the time the case was filed, that is, 1997-2006. *E.g.*, NS-PGL Init. Br. at 104-108. The average of the last ten years was the method approved by the Commission in the *Nicor Gas* rate case, ICC Docket No. 04-0779. Statistical tests performed by the Utilities' expert witness in the instant consolidated Docket showed that a ten year average was one of the most accurate, while the thirty year average (advocated by GCI) was one of the least accurate, and would likely cause the Utilities to recover less revenue than the Commission allows. Marozas Dir., PGL Ex. BMM-1.0, 4:79 through Table 1; Marozas Dir., NS Ex. BMM-1.0 4:79 through Table 1. This is because the thirty-year average includes many years of older data from a colder climate regime. Takle Dir., PGL Ex. EST-1.0, at 32; Takle Dir., NS Ex. EST-1.0, at 32.

The Proposed Order, however, recommends that the Commission base the weather billing determinant on an average of twelve years (1996-2007), although not one party advocated this period, nor are the heating degree days for this entire period even in the record. As the Proposed Order observed, the most statistically accurate averaging periods were 8-year, 12-year, 11-year, and 10-year, in that order, with very slight differences in the amount of error. Marozas Sur., NS-PGL Ex. BMM-3.0, at 4. The Utilities proposed using the number of years at the center of this "cluster" of most accurate periods, the 10-year average. Marozas Sur., NS-PGL Ex. BMM-3.0, at 4; Marozas , Tr. at 881 to 883.

The Proposed Order recommends that the Commission use, not a 10-year average as it approved for Nicor Gas, and not the 8-year average, which had the absolute lowest statistical error, but a 12-year average, which is simply the least favorable of these four periods to the Utilities.

The Proposed Order's reasoning is that it was important to include data from 1996, a statistical outlier, and the coldest winter in over 20 years. That is not a proper statistical exercise, and constitutes the kind of intentional inclusion or exclusion of particular data points that the Commission should avoid. Statistical outliers are generally to be avoided, so intentionally inserting 1996 is not correct. It is not even appropriate as a counterbalance to the warm winter of 1998, as the Proposed Order would suggest. 1998 is not a true outlier: the winters of 1999, 2000, and 2002 almost matched it. Marozas Dir., PGL Ex. BMM-1.0, p. 6, Fig. 1; NS Ex. BMM-1.0, p. 6, Fig. 1.

The Utilities continue to believe that the proper way to come up with a good averaging period is to pick a number like ten years, with a low statistical error, and the same averaging period as its neighboring utility. Marozas, Tr. 882. This prevents artificial manipulation of the numbers, including attempts to include certain data points and exclude others. Accordingly, the Proposed Order should be revised as set forth in Exception No. 16 in the NS-PGL Exceptions.

VII. <u>NEW RIDERS</u>

A. <u>Overview</u>

The Proposed Order improperly rejects Rider ICR and Riders VBA and WNA. Rider ICR is a rate mechanism that will address a unique circumstance on the Peoples Gas system, *i.e.*, the existence of nearly 2,000 miles of CI/DI mains that need to be replaced with more up–to-date facilities. Peoples Gas has demonstrated on the record that a considerable benefit to the Peoples Gas system and the City of Chicago's infrastructure would ensue from the acceleration of the replacement of CI/DI pipe. Aside from shortening the replacement period from over 40 years to a considerably lesser time frame, the main replacement would modernize the system and provide meaningful and measurable costs savings to ratepayers. The record reflects evidence that Peoples Gas can incorporate certain savings into the implementation of Rider ICR. The Proposed Order failed to account for these savings and to acknowledge the significance of Peoples Gas' adoption of certain modifications to its Rider ICR proposal. These savings and modifications to the original Rider ICR proposal amply address any concerns that might be urged in respect of the legality of Rider ICR.

Similarly, though Rider VBA and alternatively, Rider WNA, involve the implementation of rate adjustment mechanisms involving margin revenues, the riders themselves do not violate Illinois law and the Proposed Order does not reflect an appropriate analysis that supports such a conclusion. Rider VBA can be lawfully approved by this Commission with protections that account for its first time adoption in Illinois. As an alternative, Rider WNA can be approved by the Commission as an interim rates design measure pending further consideration of decoupling.

B. Riders VBA and WNA

1. Rider VBA

Exception No. 17

The Proposed Order errs in rejecting Rider VBA. The Proposed Order does not, however, provide a reasoned basis for rejecting Rider VBA under the criteria established by the Commission and the cases reviewing the implementation of automatic rate adjustment mechanisms or riders in Illinois. The Proposed Order correctly notes that Rider VBA is a decoupling mechanism proposal of first impression before the Commission and that the purpose of Rider VBA is to hold utility margin revenues constant despite changes in customer consumption. The Proposed Order, however, rejects Rider VBA in spite of its explicit recognition that Rider VBA is symmetrical (correcting rates up or down as needed), that energy efficiency and rising prices are important factors that will likely decrease usage, and that weather is unpredictable and regularly causes the Utilities to over-recover and under-recover. The Proposed Order does not find that Rider VBA would violate Illinois law, saying that "we pass the question". Proposed Order at 132. As discussed in the Utilities' post-hearing briefs, a decoupling rider is no more illegal in Illinois than it is in the numerous states that have approved similar riders. The essential rationale of the Proposed Order is that Rider VBA is new to Illinois. Understandably, that gave the ALJs pause when facing the issue for the first time, and the Proposed Order devolves into defensive discussion of "safeguards", pilot programs, studies, and legislative encouragement. However, as the record reflects, Rider VBA is designed with the necessary symmetry, transparency, and accountability that has made it effective in other states. The Utilities request the Commission to take this issue on now, and move forward on this important mechanism to the benefit of the Utilities and their customers.

Specifically, the Proposed Order finds that Rider VBA is not the type of mechanism that the Commission has authority to adopt because Rider VBA is "fundamentally different" from any other rider that has been authorized in Illinois.[9] The Proposed Order reasons that Rider VBA must be rejected because the particulars and the experience of other jurisdictions with decoupling must be studied by the Commission and because an appropriately designed decoupling

[9] While the Proposed Order passed the issue, it nevertheless notes that Rider VBA concerns revenues and not costs, suggesting that revenues are not appropriately included in a rider. As will be discussed in more detail in this Brief, there is nothing in the rider cases that have been litigated in Illinois that proscribes the inclusion of revenues in any rider recovery. Thus, the suggestion that revenue recovery is an objectionable feature of Rider VBA should be removed from the Proposed Order.

mechanism must be accompanied by ratepayer safeguards and/or a pilot feature. These reasons for the rejection of Rider VBA are flawed and inappropriate.

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' systems in view of the particulars of declining and variable customer usage patterns and the concomitant revenue recovery impacts for Peoples Gas and North Shore. The evidence permits findings that usage patterns and margin recovery fluctuations justify a decoupling rate design, without further study or evaluation of the experience of other jurisdictions or other utilities. Furthermore, the Commission has ample authority to condition the approval of a decoupling mechanism like Rider VBA upon the accompaniment of such safeguards as the Commission might deem appropriate consistent with the evidentiary record, such as a pilot feature or other appropriate condition.

As the Proposed Order aptly points out, the threshold question is whether Rider VBA is legal. The Proposed Order "passes" this question, but acknowledges that the use of riders is appropriate when there are costs at issue that are either unexpected, or volatile or fluctuating. The Proposed Order agrees with Staff that Rider VBA is fundamentally different from previously authorized riders, suggesting that Rider VBA's revenue recovery feature is unlawful in the context of a rider and citing *A. Finkl & Sons Co. v. ICC*, 250 Ill. App. 3d 317 (1st Dist. 1993) ("*Finkl*"). This analysis is over-simplified and flawed.

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 at 327. 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 *Finkl* . . . the Court . . . found that demand-side management expenses were not of such a nature as to require rider treatment . . .

CILCO v. ICC, 255 Ill. App. 3d 876, 884-885 (3rd Dist. 1993) ("*CILCO*").

Indeed, in its review of Commission ratemaking and rider cases in particular, the Illinois Supreme Court has held that the Commission enjoys 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 (1958) ("*City I*"), the Supreme Court unambiguously held that the Public Utilities Act (PUA) gives the Commission broad authority to approve rates that are not fixed and that change from time to time, *i.e.*, the authority to approve riders:

> [I]t 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.

City I, 13 Ill. 2d at 611. The *City I* Court did not articulate any restriction on the Commission's power 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.

City I, 13 Ill. 2d at 613 (citing *City of Norfolk v. Virginia Electric & Power Co.*, 197 Va. 505, 90 S.E.2d 140, 148 (1955)).

Neither *City I* nor any subsequent case involving riders has placed any restriction on the Commission's discretion 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. Simply put, there is no judicial or Commission articulated restriction on 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 is not otherwise unlawful. 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 I*, *i.e.*, a rate schedule that contains "provisions which will affect the dollars-and-cents cost of the product sold." *City I*, 13 Ill. 2d at 611.

The *City 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.

City I, 13 Ill. 2d at 613.

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 Act. Therefore, the adjustment contemplated under Rider VBA is precisely the type of adjustment mechanism contemplated in *City 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.

There is also no requirement under Illinois law that for a rider to be lawful, there must have been in existence any preexisting or "preferable technique" for handling the particular costs at issue. *City I* did indeed involve a rate adjustment for a category of expense for which the Commission had employed a prior rate design practice. Gas costs, which were the subject of the rider approved in *City I*, had been previously recovered in the base rates of Peoples Gas, the utility seeking the gas charge rider. While the *City I* Court discussed the matter, its discussion was simply an aside, or *dicta*. Specifically, the *City I* Court found that the question of "preferable technique" is not one which is appropriate for judicial review, indicating it was a matter to be determined by the Commission. *City I*, 13 Ill. 2d at 618. Neither the Court nor the Commission appears to have articulated the preferable technique principle as a criteria for rider treatment. The Court's holding certainly did not limit the Commission's exercise of discretion to employ riders to those instances where the particular matters for recovery have previously been the subject of a specific rate recovery method or approach. Such a restriction has also not been articulated or applied in any subsequent rider case in Illinois.

Moreover, even if it were conceded that there is a "preferable technique" test for the approval of Illinois riders, Rider VBA would meet the test because margin revenues have always been previously recovered in base rates (as was the case for purchase gas costs prior to rider treatment).[10] Rider VBA only enhances the preexisting base rate recovery of margin revenues by employing a rider feature to permit greater assurance of revenue recovery and minimize revenue recovery fluctuations. Therefore, the revenues to be recovered under Rider VBA most certainly have been subject to a prior rate recovery practice by the Commission.

There is simply no legal bar to Commission approval of a decoupling mechanism, such as Rider VBA. As has been discussed above, the Illinois Supreme Court has confirmed that the Commission has broad latitude in setting utility rates, including making appropriate pragmatic adjustments. *See City I*, 13 Ill. 2d at 618, citing *Federal Power Commission, et al. v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944); *Federal Power Commission, et al. v. Natural Gas*

[10] Other litigated rider cases involved the recovery of, *e.g.*, municipal fees and manufactured gas plant cleanup costs. In the case of the former, they were previously recovered in base rates. S*ee City of Chicago v. ICC*, 281 Ill. App. 3d 617 (1st Dist. 1996) (*City II"*). In the case of the latter, they were not necessarily the subject of any past recovery practices since they were unique costs which had not been previously defined for recovery as such. *See CILCO*, 255 Ill. App. 3d at 876.

Pipeline Co., 315 U.S. 575, 586 (1942). The broad latitude to employ pragmatic adjustments applies not solely to whether the Commission may implement riders but more generally to Commission ratemaking authority.

> The commission is not just an umpire. It has been given active functions of policy making and supervision. It may initiate hearings on its own motion, and it has a wide discretion in shaping proceedings brought by others. The act provides that rates shall be reasonable; but it entrusts the enforcement of that obligation in the first instance to the commission.

City I, 13 Ill. 2d at 618.

Thus, as long as the Commission has not engaged in an abuse of discretion (and acts consistent with the evidence), it may exercise its judgment to employ novel ratemaking techniques, including decoupling mechanisms. Indeed, permitting the adjustment of utility charges to reflect changes in the revenue collections to which the utility is entitled are precisely the type of pragmatic adjustments contemplated by *City I*.

Moreover, the circumstances that gave rise to *City I* are strikingly similar to those that exist in respect of Rider VBA. *City I* involved consideration of whether to adopt a type of rider to permit the automatic adjustment of purchased gas charges proposed for the first time in Illinois by Peoples Gas. Here, Rider VBA is a request by Peoples Gas and North Shore for approval of a type of rider to permit the automatic adjustment of margin revenue recovery for the first time in Illinois.

The subject of the *City I* rider was wholesale natural gas costs, the charges for which were fixed and established by the Federal Power Commission, just as the margin revenue levels in the instant proceeding will have been fixed and established by the Commission. The rider approach was proposed, no doubt, to reflect the changed business conditions of escalating commodity gas costs relative to other utility expenses recovered in rates. "In 1955 the wholesale cost of natural gas, fixed by the FPC, amounted to approximately 46% of the operating expense of Peoples, and constituted the largest item of such expense." *City I*, 13 Ill. 2d at 609. 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) 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, as even the Proposed Order acknowledges.[11]

Further similarities exist. Also in *City I*, there had been earlier adoption of automatic gas purchase cost adjustment mechanisms in a number of other jurisdictions. At the time the *City I* case was decided, utilities in many states had approved purchased gas cost riders:

> Many State public utility commissions, operating under similar statutory provisions, have approved automatic adjustment clauses, as is indicated in the Public Utility Reports (PUR). *Re Worcester Gas Light Co.* (Mass.1955) 9 PUR 3d 152; *Re New Jersey Natural Gas Co.* (1954) 6 PUR 3d 249; *Re Virginia Electric & Power Co.* (1954) 7 PUR 3d 108; *Re Wisconsin Power & Light Co.* (1955) 9 PUR 3d 422; *Re Washington Gas Light Co.* (D.C. 1954) 4 PUR 3d 105.
>
> At the close of 1954, sixty-five gas distributing Utilities in twenty-six States had adjustment clauses in their rate schedules based on the cost of purchased gas, and twenty-two [Utilities] in twelve States had adjustment clauses based on either cost of purchased gas or fuel to manufacture gas.

City I , 13 Ill. 2d at 611-612.

The existence of the practice in other jurisdictions was thus a factor in the decision to apply automatic adjustment clauses to purchased gas costs in Illinois, and specifically, on the Peoples Gas system. Similarly today, decoupling provisions, such as Rider VBA have been widely approved and implemented across the nation and their wide employment is one sound reason why Illinois should authorize decoupling. Finally, approval of the purchased gas adjustment

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[11] "We do not minimize the Utilities (*sic*) business challenges in this term of high gas prices and the various responses being undertaken." Proposed Order at 133.

rider in *City I* occurred in a case specific to Peoples Gas and not in a generic proceeding. Peoples Gas and North Shore here seek approval of decoupling in their individual rate case proceedings.

Thus, against the backdrop of the circumstances present in *City I* and the circumstances present in the instant case, it is clear that the Commission has the authority to exercise its discretion to approve decoupling for the Utilities. The demonstration of compelling business conditions for a particular utility can be the basis for the Commission to employ a rate recovery mechanism new to Illinois but implemented more broadly in other jurisdictions. Therefore, the Proposed Order errs in suggesting that implementation of Rider VBA or decoupling in Illinois should be deferred pending study or evaluation of the mechanism in other jurisdictions. Indeed, should the Commission have any reservations about the long term impact of decoupling as a viable mechanism in Illinois, the Commission is not without the power to condition the applicability of Rider VBA. The Commission is free to make such "pragmatic adjustments" as it deems appropriate. Such adjustments could include conditions that Rider VBA may only be implemented as a pilot mechanism, or that Rider VBA be subject to a time frame within which it may remain effective or be subject to the Utilities' being required to file a new rate case to justify its continuation beyond a definitive time frame. Conditioning approval of Rider VBA upon its implementation as a pilot program with directions that the parties reevaluate the mechanism after a designated time frame or conditioning continued implementation of Rider VBA after a specific time frame on the Utilities filing a new rate case would offer significant protections to ratepayers. 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 superior to, for example, study and evaluation of the particulars and experience of decoupling in other states.

The Proposed Order also errs in its reliance on the results of the instant rate case, particularly the energy efficiency program impacts, as justification for not approving Rider VBA. In doing so, the Proposed Order simply dismisses the record evidence of the business challenges faced by the Utilities, while awarding the beneficial effects of the implementation of energy efficiency programs which the record clearly establishes will worsen the Utilities' business challenges by further diminishing the Utilities' ability to recover margin revenues. The Proposed Order offers the oblique suggestion that postponement of consideration of the Utilities' business challenges and effectuating a reasonable rate mechanism to address them by approving decoupling can wait until some ill-defined point in the future. This approach is inequitable and is inappropriate because it confers the benefits of conservation on ratepayers while in no way addressing the negative consequences of that admittedly positive outcome on the business results of the Utilities.[12] Such an outcome is therefore unreasonable and produces an arbitrary result for the Utilities. A more measured approach would be for the Commission to approve the energy efficiency programs and the other rate design changes proposed by the Utilities and evaluate their overall effectiveness through operation of Rider VBA. To simply approve only the elements that benefit ratepayers and to defer or eliminate consideration of the impacts of these benefits on the Utilities is arbitrary and an abuse of discretion.

[12] This is a particularly ironic outcome in view of the Utilities' embrace of conservation through their support of Rider EEP and the record evidence where the Utilities caution that the impact of conservation is to reduce their ability to recover revenues under traditional rate structures and to preserve the throughput incentive without responsive rate mechanisms, such as decoupling. *See* Feingold Dir., PGL Ex. RAF-1.0, at 25. The Proposed Order, in recommending approval of Rider EEP, states that "[w]e expect any money the EEP spends on energy efficiency will decrease the Utilities (*sic*) revenues as customers use less gas." Proposed Order at 170. The Proposed Order is recommending approval of a rider that will exacerbate the problem that Rider VBA is intended to address.

The Proposed Order further errs in its analysis of Riders by emphasizing that the subject of a rider must involve a cost which imposes a "burden" on the utility. The Proposed Order improperly focuses its burden analysis on whether the Utility could avoid or control a cost. Such an analysis is misplaced. The analysis should appropriately center on whether a cost is "inevitable". The Proposed Order does not analyze Rider VBA by applying the burden test. As indicated above, the Proposed Order's legal analysis of the legality of Rider VBA under Illinois law is minimal, although it is much more detailed in respect of the legal analysis of Rider ICR. To the extent that the Proposed Order's legal analysis of Rider ICR, however, may be deemed applicable to other riders, including Rider VBA, any burden analysis is misplaced for the reasons discussed below in connection with Rider ICR.

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. Hence, 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 the Proposed Order itself concedes, 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. *See* Proposed Order at p. 170. As with the municipal franchise fees approved for rider treatment in *City 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 II*, the margin revenues which are recovered under Rule VBA do not involve single issue ratemaking because they do not have any impact whatsoever on the Utilities' overall revenue requirements or rates of return. *See City II*, 281 Ill. App. 3d at 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.

Finally, the Proposed Order errs in its assertion that the General Assembly should provide the Commission with authority to examine decoupling or consider decoupling in light of the State's rising concern for energy efficiency and conservation measures. The Proposed Order is in error because, as has been discussed extensively above, the Courts have already held that the Commission possesses broad authority to implement appropriate rate mechanisms, including riders and any other pragmatic adjustments to rates that the Commission deems appropriate. *City I*, 13 Ill. 2d at 618; *City II*, 281 Ill. App. 3d at 628. Just as the Commission 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. What is involved is merely a policy decision to employ a new rate design approach, as occurred in *City I*. There was no need for legislation authorization at that time and the Court found that the PUA contemplates such changes in approach. The Act likewise permits the Commission to employ decoupling for the Utilities in the form of Rider VBA without any additional guidance from the General Assembly.

2. **Rider WNA**

Exception No. 18

The Proposed Order errs in its rejection of Rider WNA. The Proposed Order does not sufficiently examine the evidence of record which establishes the propriety of Rider WNA. Rather, the Proposed Order rejects Rider WNA simply because Rider VBA was not accepted. The Proposed Order largely ignores the fact that Rider WNA was proposed as an alternative to Rider VBA. Rider WNA contains features that are substantially different than those contained in Rider VBA. As the Proposed Order correctly notes, Rider VBA would work to capture the broader effects of customer usage, whether weather induced or due to the effect of conservation, rising natural gas prices, utility promotion of energy efficiency or other events. *See* Proposed Order at p. 132. Rider WNA, by contrast, is more narrowly focused. Rider WNA will only adjust customer bills on a monthly basis for the effect of weather.

As with Rider VBA, the record establishes that the Utilities have not been able to recover approved margin revenue levels over the past 9 years. *See* PGL Ex. RAF-1.4; NS Ex. RAF-1.4. As the record further establishes, this erosion of margin revenues can result in an erosion of the Utilities' financial standing. Thus, the inability of the Utilities to fully recover margin revenues is a reasonable basis on which to determine that some rate design relief is warranted. As was discussed above, the Utilities believe that Rider VBA would provide them with the most comprehensive protection against the proven erosion in the recovery of margin revenues. Rider VBA would stabilize margin revenues whether any potential loss of revenue recovery is attributable to weather or other factors. It cannot be disputed that both weather and customer usage variations attributable to other factors contribute to fluctuations in utility margin revenues. These fluctuations will tend to become more significant in the changing global climate and as a result of the energy efficiency programs which will be implemented on the Utilities' systems. To deny the Utilities any relief whatsoever from these undeniable impacts is unreasonable and arbitrary.

By rejecting both Rider VBA and Rider WNA, the Proposed Order is arbitrary and unreasonable. 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, while Rider WNA would provide somewhat less stability, but more stability than with no mechanism to address the climate and conservation challenges. If the Commission believes that Rider VBA is too broadly focused or that there are aspects of decoupling that are unclear, Rider WNA is the most meaningful alternative, and the Proposed Order should have so determined given the evidence in the record.

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.[13] Moreover, a weather normalization adjustment could be an interim step pending more evaluation and consideration of decoupling.

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 factors used to calculate the Rider WNA adjustment would be established in these rate proceedings and set forth in the tariffs. The calculation

[13] The Proposed Order suggests that decoupling has been often implemented on a pilot basis or with other restrictions. No such finding is made in respect of weather normalization adjustment mechanisms.

considers only the impact (positive or negative) of the difference between actual heating degree days and the normal established by the Commission in this proceeding. Any adjustments that result by operation of Rider WNA would occur within the Commission established base rates and Rider WNA would operate simply as a mathematical formula which would generate a charge or credit adjustment to the Commission determined base rate. 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 I*, 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 because Rider WNA does not involve the impact of any set of costs and expenses on the revenue requirement or rate of return. Rider WNA simply computes a charge or credit based on Commission determined rate components and whether weather was warmer or colder than the normal degree days used in setting rates. 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 the Utilities and their customers are afforded equal treatment in the operation of the rate adjustment.

Rider WNA gives due consideration to the impacts of weather on the Utilities' rates. To completely deprive the Utilities of any opportunity to adjust rates for a known impact which impedes the ability to fully recover approved base rates would be punitive toward the Utilities. A weather normalization mechanism is an equitable and widely accepted means of balancing utility and ratepayer interests and, absent approval of Rider VBA, should be given favorable consideration by the Commission. See Exception No. 18 in the NS-PGL Exceptions.

C. **Rider ICR**

Exception No. 19

The Proposed Order errs in rejecting Rider ICR. The Proposed Order does not provide a properly reasoned basis for rejecting Rider ICR under the applicable criteria. The Proposed Order acknowledges that the "issues concerning Rider ICR are the same posed by the other proposed riders", *i.e.*, does the Commission have the discretionary power to authorize rider recovery and should the Commission exercise that authority in this instance. Proposed Order at p. 144. The Proposed Order concludes incorrectly, however, that the Commission is precluded from authorizing the implementation of Rider ICR. The Proposed Order does so by misapprehending the legal criteria which have been articulated by the Commission and the courts in respect of the Commission's ratemaking authority. There is no question that the PUA and the Illinois courts have affirmed that the Commission has ample authority to approve an automatic adjustment mechanism to recover the costs that are the subject of Rider ICR. The Proposed Order errs in rejecting Rider ICR because it does not involve costs that are volatile, fluctuating or unexpected and violates the proscription against single issue ratemaking

The Illinois Supreme Court has held that the Commission enjoys broad discretion to employ riders and to make appropriate pragmatic rate adjustments. The seminal case which sets forth the Commission's authority to employ riders is *City I* (13 Ill. 2d at 607). In *City I*, the Supreme Court unambiguously held that the PUA gives the Commission broad authority to approve rates that are not fixed and that change from time to time, *i.e.*, the authority to approve riders:

> [I]t 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 a whole, contemplates that a rate schedule may contain provisions which will affect the dollar-and-cents cost of the product sold.

City I , 13 Ill. 2d at 611.

The *City I* Court did not articulate any restriction on the Commission's power 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.

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

Neither *City I* nor any subsequent case involving riders has placed any restriction on the Commission's discretion to approve riders because a rider might recover the depreciation and carrying costs associated with capital investments, particularly when, as here, those costs would be subject to an annual prudence review. In *City 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 I*, 13 Ill. 2d at 618.

The Proposed Order generally cites *City I* as granting the Commission discretion to implement riders and exercise pragmatic ratemaking powers. The Proposed Order errs, however, when it asserts that *City I* imposes a condition on the Commission's employment of riders in a given situation. The Proposed Order suggests, in its analysis of Rider ICR, that before a rider can be employed in Illinois, there must have been a "preferable technique" for handling the costs in question which the Commission has utilized prior to implementation of any automatic adjustment mechanism. The Proposed Order characterizes this "preferable technique" test as the "dispositive issue in evaluating the lawfulness of a rider," Proposed Order at 145, and found 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."

The Proposed Order's interjection of a "preferable technique" analysis reflects a misunderstanding of the applicable law. There is simply no requirement under Illinois law that for a rider to be lawful, there must have been in existence any preexisting or "preferable" technique for handling the particular costs at issue. *City I* did indeed involve a rate adjustment for a category of expense for which the Commission had employed a prior rate design practice. Gas costs, which were the subject of the rider approved in *City I*, had been previously recovered in the base rates of Peoples Gas, the utility seeking the gas charge rider. While the *City I* Court discussed "preferable technique", its discussion was simply an aside, or *dicta*. Specifically, the *City I* Court found that the question of "preferable technique" is not one which is appropriate for judicial review, indicating it was a matter to be determined by the Commission. *City I*, 13 Ill. 2d at 618. Neither the Court nor the Commission articulated the "preferable technique" principle as a criteria for rider treatment. The Court's holding certainly did not limit the Commission's exercise of discretion to employ riders to those instances where the particular matters for recovery have previously been the subject of a specific rate recovery method or approach. Such a restriction has also not been articulated or applied in any subsequent rider case in Illinois. The "preferable technique" analysis in the Proposed Order is a misinterpretation of *City I*.

Furthermore, the Proposed Order's elevation of the "preferable technique" test to a precondition for the approval of a rider is unsupported by a plain reading of *City I*. Indeed, if the "preferable technique" test were a precondition to a rider as countenanced by the Proposed

Order, it would be virtually impossible for any new rider to pass muster. The Proposed Order articulates the "preferable technique" test for Rider ICR thusly, at p. 145:

> [W]e 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.

Aside from reflecting a misunderstanding of the operation of Rider ICR,[14] the test as set forth above basically states that unless the elements of recovery under a rider have not been already recovered in the manner proposed in the rider, they are not eligible for rider treatment.[15] This is unsound reasoning and if it were indeed a precondition for rider treatment, it is difficult to comprehend how, for example, coal tar cleanup costs could have met the "preferable technique" test. Those costs, like the CI/DI main replacement costs under Rider ICR, were one time expenses for unique circumstances, and had not necessarily been the previous subject of any particular rate recovery method. The only conditions that have been established as prerequisites for riders is that in appropriate circumstances, they do not violate test year or single issue ratemaking proscriptions, or that they reflect certain cost behaviors or unique characteristics, as discussed later. In any event, there is no basis for imposing a "preferable technique" test for the approval of a rider.

The Proposed Order also incorrectly applies the *Finkl* case in respect of Rider ICR. 250 Ill. App. 3d at 317. *Finkl* does not preclude a finding that Rider ICR costs are unexpected,

[14] The Proposed Order appears to incorrectly assume that Rider ICR is intended to incorporate depreciation and carrying costs into base rates. Rider ICR will only recover depreciation and carrying costs until the capital investments are incorporated into base rates in a rate case.

[15] It could be argued, however, that the depreciation and carrying costs under Rider ICR are proxies for the depreciation and return on rate base that has been the traditional means of addressing capital expenses. Thus, there is in fact a "preferable technique" in regards to Rider ICR charges.

volatile or fluctuating and *Finkl* does not require a showing of burden, as implied by the Proposed Order.

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 made an explicit factual finding that the costs associated with the lost revenue were not "unexpected, volatile or fluctuating expenses which Edison cannot control". *Finkl*, 250 Ill. App. 3d at 327. The *Finkl* Court's emphasis was on the facts pertaining to the incremental expenses associated with the demand-side management program and not that riders *per se* are prohibited or that riders necessarily *per se* violate retroactive ratemaking, test year rules or any other legal prescriptions. This interpretation has been articulated subsequent to the *Finkl* decision. *See CILCO*, 255 Ill. App. 3d at 884-885.

Finkl turned on a determination by the Court that the expenses of Edison's demand side management program were not unexpected, volatile or fluctuating. Peoples Gas has demonstrated otherwise in respect of Rider ICR costs. Peoples Gas has shown 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 certainly unpredictable and uncertain. The Rider ICR costs are more akin to those which were the subject of *CILCO*, where the Court found that the recovery of coal-tar cleanup costs to be a permissible rider cost. In *CILCO*, the court found:

> The record shows these costs will vary widely from year to year depending on the type of remediation activities: from relatively small sums in the thousands (investigation costs) to the millions of dollars (actual cleanup costs). We view these costs as the type of unexpected, volatile and fluctuating costs which are more efficiently addressed through a rider mechanism.

CILCO, 255 Ill. App. 3d at 885. As in *CILCO*, in the present case, 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. The acceleration of CI/DI main replacement, like the coal tar cleanup costs, will vary from year to year to year, depending upon the unexpected opportunities that arise to replace existing main. 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 any criteria that rider costs be unexpected, volatile or fluctuating and the Proposed Order should have reached that conclusion unambiguously.[16]

The Proposed Order goes on to find that CI/DI main replacement cost fluctuations can be avoided, thereby suggesting that there is no "burden" on the utility. As was discussed in detail earlier, an analysis of the propriety of a rider should not focus on the burden that particular costs imposed on the utility. Rather, the proper focus is on the inevitability of the costs. Nevertheless, Peoples Gas has established on the record that there remains nearly 2,000 miles of CI/DI mains to be replaced in Chicago and that eventually all CI/DI main will be replaced. Thus, while replacement of main might be delayed, there really is no avoidance of the eventual expenditures and any "burden" that might be deemed present is not diminished by timing delays.

The Proposed Order expressed concern about whether Rider ICR violates the proscription against single issue ratemaking. This concern, however, can be addressed by reference to the record in this proceeding. As the Proposed Order correctly points out, "there is no question that

[16] The Proposed Order concedes that CI/DI main replacement costs "will likely fluctuate", but dismisses this phenomenon by finding that it is avoidable by postponing work. Proposed Order at 145. This is somewhat circular reasoning since the stated purpose of Rider ICR is to give Peoples Gas the ability to capture opportunities for CI/DI main replacement in order to shorten the time frame for the complete modernization of the Peoples Gas infrastructure.

the contemplated main replacements will tend to generate savings." Proposed Order at 146. Peoples Gas has submitted evidence that establishes specific O & M savings that 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, and deferred tax savings.

In addition, it should be emphasized 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. Most of the modifications to the original Rider ICR were proposed by the Commission Staff.[17] 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, at 4.

Thus, should there be a concern about single issue ratemaking, it can be ameliorated by conditioning 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 could be required to calculate these savings based on the past year's activity in the annual reconciliation filing with the inclusion of 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.

[17] 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.

The Proposed Order further errs when it asserts that the existence of Section 9-220.2 of the Act which authorizes Part 656 and the CWIP Regulations under Section 9-214 of the Act limit the Commission's discretion to approve Rider ICR. Aside from the mere fact of the existence of those statutes, which partially address water and sewer infrastructure costs and electric utility construction costs, no basis for such a conclusion is offered. The Proposed Order is in error because the Courts have already held that the Commission possesses broad authority to implement appropriate rate mechanisms, including riders and any other pragmatic adjustments to rates that the Commission deems appropriate. *City I*, 13 Ill. 2d at 618; *City II*, 281 Ill. App. 3d at 628. Just as the Commission needed no legislative authority to employ automatic gas charge recovery adjustment mechanisms, no authorization from the General Assembly is required to implement Rider ICR. There is nothing about the costs that could be recovered under Rider ICR that are not the subject of routine, traditional Commission ratemaking. What is involved is merely a policy decision to employ a new rate design approach for a truly unique undertaking, as occurred in *City I*. There was no need for legislation authorization at that time and the Court found that the PUA contemplates such changes in approach. The PUA likewise permits the Commission to employ Rider ICR for the Utilities without any additional guidance from the General Assembly. In addition, an interpretation which would entail legislative approval of orders would impose a substantial limitation on the Commission's broad discretion conferred by *City I* and other cases. Such a sweeping interpretation, without more, is untenable and unreasonable.

A more measured view is that the Commission possesses the authority to authorize rider recovery of Rider ICR costs because, as discussed in more detail previously, 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 "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. In addition, *City 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 II*, 281 Ill. App. 3d at 628, and the Proposed Order is in accord with this interpretation. *See* Proposed Order at 146, 170.

Clearly then, there are no legal impediments to the implementation of Rider ICR, and the Commission does indeed have the discretionary authority to authorize rider recovery of the costs involved. The second half of the initial question posed by the Proposed Order is, "should [the Commission] exercise that authority in this instance?" The answer to that question is an overwhelming yes. It should not 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 of Chicago. The ability to substantially reduce the estimated 40 year time frame for the replacement of the City of Chicago CI/DI main presents a unique opportunity for the Peoples Gas system. Mr. Schott submitted an exhibit which vividly demonstrates the extent of CI/DI main present in the City of 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 City of Chicago gas infrastructure system. It simply cannot be seriously argued that the situation in Chicago is not unique in Illinois.

Citizens Utility Board v. ICC (166 Ill. 2d 111 (1995)) ("*Citizens Utility Board*") held that the Commission has the discretion to approve direct recovery of unique costs through a rider when circumstances warrant.[18] The compelling circumstances attending the CI/DI main replacement in the City of 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 II* and *Citizens Utility Board*.

While on the one hand rejecting Rider ICR, the Proposed Order nevertheless lauds Peoples Gas' efforts to improve the distribution system. The Proposed Order's treatment of Peoples Gas' efforts attaches far too little significance to them, enhancing them, as Rider ICR would entail, and the importance of significantly improving the infrastructure in the City of Chicago. Aside from the sheer magnitude of the replacement of CI/DI mains in the City of Chicago, the Commission should take cognizance of the unqualified support of Rider ICR by the City of Chicago itself.

The City of Chicago described the acceleration of CI/DI main replacement as a "significant effort to bolster and improve this critical aspect of the City of Chicago's infrastructure." City Init. Br. at 3. Peoples Gas believes that the opportunity for infrastructure modernization is a particularly acute challenge as it pertains to vintage facilities in an urban area like the City of Chicago. Rider ICR presents the Commission with the opportunity to ensure that the natural gas pipeline infrastructure of the City of Chicago is the most suitable to meet long term service requirements. NS-PGL Init. Br. at 130. The City of Chicago also acknowledged

[18] The Proposed Order attempts to limit the applicability of the "unique cost" principle to only those instances where single issue ratemaking is not at issue. Because the Commission is able to address single issue ratemaking in the manner described earlier, the Proposed Order limitation, if valid at all, need not apply.

that Rider ICR will allow Peoples Gas to coordinate with the City of Chicago and others as they pursue development projects in the City of 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. City Init. Br. at 3. The City of Chicago is the most strategic and pivotal participant, along with Peoples Gas, in the implementation of the accelerated main replacement program. Hence, the City of Chicago's recognition of the importance of Peoples Gas' effort to modernize the utility infrastructure in the City of Chicago is of major significance. As a major customer of Peoples Gas, the City of Chicago's support is even more compelling.

The Proposed Order side-stepped the policy matter of the need to modernize and enhance the utility infrastructure in the City of Chicago. In discussing Rider ICR and CI/DI replacement at page 148 of the Proposed Order, it is assumed that if "such opportunities could arise more frequently than is customary . . . PGL will know well in advance." Not only is there no basis offered for this conclusion, it is simply not well founded. The Utilities have no way of knowing whether such projects will be scheduled, nor do they know that they will "know well in advance". That is precisely why Peoples Gas has proposed Rider ICR, because the ability to accelerate the replacement of infrastructure under those circumstances is unpredictable. The Proposed Order also reasons that "for more mundane municipal projects and repairs, there is simply no evidence that the near future will differ from the recent past." Proposed Order at 148. Clearly, the Proposed Order misses the point. The issue is not whether the "project and repairs … will differ from the recent past" because that cannot be known with any certainty. Rather, the issue is whether there are unforeseen opportunities to accelerate the replacement of main and thereby modernize the infrastructure and achieve significant savings on behalf of ratepayers. The uncontroverted evidence in the record shows that indeed, that is the case. The

City of Chicago and Peoples Gas have both urged that the replacement of piping and associated infrastructure that is in some cases over one hundred years old is crucial. No party has argued that there would be a more reasonable means of accelerating main replacement and providing Peoples Gas with the necessary financial assurance.

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. The Proposed Order suggests that, "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 . . .." Proposed Order at 148. While this is true, it clearly supports Peoples Gas' claims that the opportunities for replacement are unexpected, or unpredictable. Peoples Gas does not know when or whether the opportunity to replace "significant spans of CI/DI main" will arise. That is precisely why Rider ICR would be an invaluable tool in modernizing the City's infrastructure – because it allows the utility to respond to such opportunity with greater flexibility and lessen negative cost implications than have been available heretofore. There are no 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 Chicago should have some meaning in the ultimate determination of the propriety of Rider ICR and the Proposed Order should have given this factor some weight. See Exception No. 19 in the NS-PGL Exceptions.

E. **Deferred Accounting Alternative <u>to Certain Rider Requests</u>**

<u>Exception No. 20</u>

The Proposed Order (at 176) declines to adopt deferred accounting as an alternative to proposed new Rider VBA and alternative Rider WNA. The Companies continue to believe that the amounts that would have been tracked in proposed Riders VBA/WNA, if those Riders are in fact ultimately rejected by the Commission, are appropriate for deferral and ultimate recovery in future rate proceedings. (The Companies take no Exception as to the subject of deferred accounting as an alternative to proposed Rider UBA.)

Focusing on Rider VBA, by "tak[ing] gas volumes out of the ratemaking equation," the deferral alternative for Rider VBA would normalize the Companies' recovery of the portions of their margin revenues that are recovered through volumetric charges. Feingold Dir., PGL Ex. RAF-1.0, at 11, 26; Feingold Dir., NS Ex. RAF-1.0, at 12-13, 24. By regularly monitoring and modifying the applicable margin revenues each month to account for weather fluctuations and changes in usage patterns, a margin revenue deferral account alternative to Rider VBA would allow the Companies to most closely match the amortization periods of assets (as well as the authorized revenue requirement generally) reflected in the calculations underlying the rates established in this proceeding. This would allow the Companies to prevent, not proliferate, the mismatching or overstatement of revenues and expenses that concerned the court in *Business and Professional People for the Public Interest v. Illinois Commerce Comm'n*, 146 Ill. 2d 175 (1991) ("*BPI II*").

The margin revenues that would be tracked in the deferral account alternative to Rider VBA would include "a fair and reasonable return on its utility assets" (Feingold Dir., PGL

Ex. RAF-1.0, at 15; Feingold Dir., NS Ex. RAF-1.0, at 14), the very type of cost that the court in *BPI II* upheld as appropriate for deferral because:

> post-in-service financing costs compensate [the utility] for the time value of its money which is still invested in the asset. These capital costs are a function of the value of the unused portion of the asset. We believe this is the fundamental reason the costs are treated differently for ratemaking purposes.

BPI II, 146 Ill. 2d at 242; Staff Init. Br. at 224.

The court in *Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111 (1995) ("*CUB*"), further recognized the Commission's "discretion in selecting the means by which rates are set and costs are recovered, and the appropriateness of the rider mechanism in certain instances," and that same discretion which supports the requested riders also authorizes Commission approval of the deferral accounts requested here in the alternative. *CUB*, 166 Ill. 2d at 138 ("the Commission's power is not limited to determining a mere charge or a particular rate; rather, the Commission has the power to change, under certain conditions, any part of a filed schedule rate, rule, or regulation that in any manner affects the rates charged") (*accord City of Chicago v. Illinois Commerce Comm'n*, 13 Ill. 2d 607 (1958)).[19]

As more recently stated by the Commission with respect to a residential rate stabilization program proposed by ComEd, the "Court in *BPI II*, furthermore, did not seem to suggest or assume that rate moderations plans are inconsistent with principles enunciated in *BPI II*, noting: '[o]n remand the Commission will establish new rates, and presumably a new moderation and allocation plan' … The Commission finds it significant that [ComEd does not] seek approval of a regulatory asset that would be recovered in subsequent rate proceedings." *In re*

[19] S*ee also, e.g., In re South Beloit Water, Gas and Elec. Co.*, ICC Docket No. 03-0676 (Cons.), p. 19 (Order Oct. 6, 2004) ("The types of rate recovery mechanisms that are designed to track and reconcile item-specific expenses and/or revenues on an ongoing basis for eventual matching and adjustment, such as riders, are alternatives to setting base rates via the test year ratemaking process, not part of it, as explained [in *CUB*]").

Commonwealth Edison Co., ICC Docket No. 06-0411, p. 19 (Order Dec. 20, 2006) (*citing BPI II*). *See also, e.g.*, *In re Illinois-American Water Co.*, ICC Docket No. 02-0690, p. 68 (Order Aug. 12, 2003) (deferral may be appropriate despite *BPI II*, where "deferred amounts may be used to help arrive at a more normal or representative test year allowance as an alternative to unrepresentative test year projections, but they are not used to provide a supplement or addition to a normal level of annual expenses"). Rider VBA falls squarely within these noted "exceptions" to *BPI II* because it allows for the most accurate matching of ratemaking assumptions to weather- and usage-based realities, while preventing rather than promoting any long-term carry-over of costs to future rate case proceedings. Deferral of these revenues should therefore be approved, in the event that Rider VBA is not. The same rationale applies to the narrower alternative Rider WNA. Accordingly, the Proposed Order should be revised as set forth in Exception No. 20 in the NS-PGL Exceptions.

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 Proposed Order incorrectly concludes that the Utilities' distribution system investment should be allocated using an average and peak ("A&P") allocator. The Proposed Order cites the Commission's past practice in support. Proposed Order at 185-186. The Proposed Order also includes an inaccurate statement, on page 179, in the description of the

Utilities' position; as the statement pertains to a key element of cost of service theory, the Utilities recommend revising this statement for clarity.[20]

The Proposed Order is correct that there are recent Commission decisions in gas utility rate cases in which the Commission adopted an A&P allocator for distribution system investment. The Utilities also agree that it is appropriate for the Commission to consider its past practice in resolving an issue. Proposed Order at 185. However, there is substantial evidence to support adoption of a coincident peak ("CP") allocator in this proceeding. First, while the Commission has a recent history of using an A&P allocator for gas utilities, it also has a significant history of using other allocators for distribution system investment. Moreover, when the issue has been raised in recent electric utility cases, the Commission did not adopt an A&P allocator, despite considering the issues similar to those for gas utilities. Second, there is compelling evidence for allocating distribution system costs based on design day demand. Third, in some of the cases cited on page 181 of the Proposed Order as evidence of the Commission's rejection of the CP allocator, the utility did not propose the CP allocator.

To the first point, the Commission has been receptive to the use of the CP and allocators other than A&P for gas utility distribution system investment. For example, in Peoples Gas' ICC Docket No. 90-0007, pursuant to the Commission Staff's rate design witness' recommendation, Peoples Gas modified its cost of service study to incorporate a CP allocation method. *In re The Peoples Gas Light and Coke Company*, ICC Docket No. 90-0007, p. 43 (Order Nov. 9, 1990). In ICC Docket No. 91-0586, Peoples Gas prepared its cost of service using the same methodologies

[20] The Proposed Order states, on page 179 in the description of the Utilities' position, that "[t]he CP method most closely matches the principle that cost causation should follow cost responsibility." In fact, it is cost responsibility that should follow cost causation. Amen Dir., PGL Ex. RJA-1.0, at 7; Amen Dir., NS Ex. RJA-1.0, at 7.

that it used in ICC Docket No. 90-0007 and that North Shore used in ICC Docket No. 91-0010, and the Commission approved the cost of service study. *In re The Peoples Gas Light and Coke Company*, ICC Docket No. 91-0586, p. 58 (Order Oct. 6, 1992). Less than a year prior to the 1994 CILCO order cited on page 181 of the Proposed Order, the Commission rejected Illinois Power Company's proposed "proportional responsibility" allocator in favor of Staff's proposed average and excess ("A&E") allocator, calling it the "commonly used A&E method." *In re Illinois Power Company*, ICC Docket No. 93-0183, p. 76 (Order April 6, 1994).

For electric utilities, which have a similar allocation issue, the Commission has not adopted the A&P allocator. The Commission stated in Ameren cases, decided only about one year ago, that it has traditionally used a non-coincident peak ("NCP") allocation method, which is "based at least in part on the premise that the distribution system is sized to serve maximum demand, whenever that may occur."[21] *In re Central Illinois Light Company d/b/a AmerenCILCO et al.*, ICC Docket Nos. 06-0070, 06-0071, 06-0072 (Cons.), p. 164 (Order Nov. 12, 2006). The Commission rejected arguments advocating a move to A&P, stating that:

> We continue to believe that the overall principle of allocating costs to those responsible for the incurrence of the costs is reasonable and should be encouraged. Distribution system costs, as IIEC states, are incurred on the basis of the number of customers and the demand of those customers, not their usage. We agree with Ameren and IIEC that the size of the facility, such as wires and transformers installed to serve customers is a function of maximum demands that the customers served by those facilities place on them.

Id. at p. 165. Commonwealth Edison Company likewise had used NCP and CP to allocate costs in a case decided only months prior to the Ameren cases, and the Commission accepted this

[21] Utilities witness Amen described the NCP method as recognizing that certain facilities are designed to serve local peaks that may not coincide with system peaks. Demand costs are allocated on the basis of each rate class' maximum demand, irrespective of the system peak. Amen Dir., PGL Ex. RJA-1.0, at 15; Amen Dir., NS Ex. RJA-1.0, at 15.

approach while stating only that it remains open to considering A&P "due to similarities between the natural gas and electric distribution business." *In re Commonwealth Edison Company*, ICC Docket No. 05-0597, p. 172 (Order July 26, 2006).

In sum, the Commission use of an A&P allocator is not as "established" and "long-standing" a "tradition" as the Proposed Order concludes on page 186.

To the second point, there are sound reasons the engineering dictum that the distribution system must be able to meet design day demands[22] should determine how to allocate the distribution costs. As the Commission stated in Nicor Gas' most recent rate case, "[t]he underlying issue is the method that best allocates transmission and distribution demand costs to those that cause them." *In re Northern Illinois Gas Company d/b/a Nicor Gas Company* ("*Nicor Gas*"), ICC Docket No. 04-0779, p. 101 (Order Sept. 20, 2005). There is no dispute that the Utilities must size their distribution system to meet peak day demand. Staff Ex. 7.0, at 13; CUB-City Ex. 2.0, at 28. Consequently, the facts that customers use gas on days other than the peak (CUB-City 1.0, at 72-73) has no mitigating effect on the size and amount of pipe and, consequently, the cost of the pipe, that the Utilities must put in the ground. Likewise, a customer with a 100% load factor relative to a customer with a 20% load factor does not, by reason of the higher load factor, require a larger pipe to serve it and does not cause the Utilities to incur additional distribution costs. Indeed, if the 20% load factor customer has a higher peak day demand, that customer has had a greater impact on distribution investment. For example, a non-heating residential customer would likely have very high load factor usage because his consumption is largely unaffected by weather while a heating customer will likely have a lower load factor but use more gas, especially on the peak.

[22] Doerk Dir., PGL Ex. ED-1.0, at 4; Doerk Dir., NS Ex. ED-1.0, at 4.

The Commission's stated purpose of the distribution allocator is to allocate the distribution costs to those customers who cause them to be incurred. It is customers' peak day demand that causes the distribution costs to be incurred and is the proper allocator. Other factors associated with the use of the system -- for example, average demand or total throughput -- are not cost causation factors in the context of allocating the distribution investment. These other factors may be pertinent to rate design or allocating other costs, for example costs that vary with throughput, but they are not driving the distribution investment.

To the third point, page 181 of the Proposed Order, in summarizing Staff's position, cites several Commission orders in which the Commission adopted the A&P allocator for a gas utility. Note, however, that in two of the recent proceedings (ICC Docket No. 04-0779[23] and ICC Docket Nos. 02-0798, 03-0008 and 03-0009 (Cons.))[24], the utilities did not propose the use of the CP allocator. In the latter case, no party proposed the CP allocator, and, therefore, the Commission was not finding that the A&P allocator was preferable to the CP allocator.

The CP allocator is the appropriate allocator for the Utilities' distribution system investment. See Exception No. 21 in the NS-PGL Exceptions.

b) Classification of Uncollectible Account <u>Expenses Account No. 904</u>

<u>Exception No. 22</u>

The Proposed Order incorrectly concluded that Account No. 904 (Uncollectible Accounts) should be classified as customer, demand and commodity costs and approved Staff's proposal for implementing the classification. Proposed Order at 187. First, the Proposed

[23] *Nicor Gas* at p. 95.

[24] *In re Central Illinois Public Service Company (AmerenCIPS) and Union Electric Company (AmerenUE)*, ICC Docket Nos. 02-0798, 03-0008, 03-0009 (Cons.), p. 93 (Order Oct. 22, 2003).

Order's recommendation is inconsistent with cost causation principles. Second, the recommended apportionment method is flawed because it is circular and uses gas costs that should not be a factor in a base rate calculation.

Classification

Cost causation is the driving force behind the embedded cost of service study ("ECOSS"). Amen Dir., PGL Ex. RJA-1.0, at. 7; Amen Dir., NS Ex. RJA-1.0, at 7. Costs are classified into the three cost-defining characteristics of customer, demand or commodity. Amen Dir., PGL Ex. RJA-1.0, at 8; Amen Dir., NS Ex. RJA-1.0, at 8. In other words, "classification" is addressing why was a particular cost was incurred. Staff's proposal is based on where the costs underlying the uncollectible accounts originate (Luth Reb., Staff Ex. 19.0, at 3-4; *also see* Proposed Order at p. 187) and not why the uncollectible account expense occurred. The uncollectible expense occurs, as Staff agrees, because customers do not pay bills. Luth Reb., Staff Ex. 19.0, at 3-4. The uncollectible expense arising from unpaid bills is a discrete expense. That expense is not one or a combination of the cost elements that make up the customer, distribution, and gas charges, and those underlying cost elements are unaffected by the unpaid bills. Amen Sur., NS-PGL Ex. RJA-3.0, at 7.

Another fundamental principal of cost of service is that a cost is allocated to rate classes based on the relative portion of the cost caused by the customers in each rate class. *See, e.g.*, Amen Reb., NS-PGL Ex. RJA-2.0, at 14. The uncollectible expenses should, therefore, be allocated to the rate classes that failed to pay them, *i.e.*, caused them to be incurred. Allocating the uncollectible expense according to the origin of the underlying costs (customer, demand, commodity) would essentially be a redundant allocation of those same costs to the classes. The Utilities properly allocated the uncollectible accounts expense because they used an allocation factor that specifically identified the percentages of the expense caused by the customers in each rate class. Amen Reb., NS-PGL Ex. RJA-2.0, at 14.

Staff's Method

The Proposed Order states that it accepts Staff's method for apportioning the expense. Proposed Order at 187. The Staff's method would apportion the expense by the relative weights or the percentage of revenue requirements of each customer class resulting from demand, commodity, customer and gas costs. This method is flawed. It is circular in nature. Non-gas expenses are included in the determination of the revenue requirement. Yet the Staff's method requires the revenue requirement to be used to apportion the expenses. In addition, gas costs, which are not base rate expenses, would be used to apportion base rate expenses. That is inappropriate.

Account No. 904 expenses should be classified as customer costs and allocated pursuant to the Utilities' proposal. See Exception No. 22 in the NS-PGL Exceptions.

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

<u>Exception No. 23</u>

The Proposed Order incorrectly concluded that Peoples Gas' Account No. 385 (Industrial Measuring and Regulating Station Equipment) costs should be directly assigned to individual customers. The Proposed Order stated that, when the Utilities can identify specific plant costs with individual customers, then it is appropriate to rely on that. However, the Proposed Order also stated that "[t]o the extent practicable, a sound rate structure should include the practical attributes of simplicity, understandability, certainty and feasibility of application." Proposed Order at 198.

While it may be possible for Peoples Gas to directly assign the Account No. 385 costs to individual customers, within the context of the ECOSS, sound rate design does not require translating such assignment into customer-specific charges. Such direct assignment would not enhance fairness and equity, two attributes that the Proposed Order attributes to GCI witness Glahn's proposal (Proposed Order at 198), nor would it enhance the simplicity and understandability of Peoples Gas' rates.

First, Peoples Gas has the capability of assigning plant costs of meters, regulators and services to individual customers in all its service classes, and the Utilities' ECOSS reflects this fact. Amer. Sur., NS-PGL Ex. RJA-3.0, at 10-11.[25] Account No. 385 is but one set of those costs. The record does not support a conclusion that it is fair and equitable to single out this particular account for customer-specific charges.

Second, while the record includes the estimated, *de minimis* impact of direct customer assignment of Account No. 385 (Amer. Sur. NS-PGL Ex. RJA-3.0, at 11), there is no consideration of the possible impact of designing customer-specific charges for other costs for which company records would permit such recovery. For example, if the Utilities directly charged to individual customers other costs, the customers affected by the Account No. 385 assignment may see offsetting benefits as other costs could be removed from their rates. When many metering, regulator and service costs are capable of direct assignment to and recovery from individual customers but only one account is singled out for this treatment, it is not fair and equitable to the group of customers who are singled out.

[25] The Proposed Order would require direct assignment of certain costs to individual customers as distinguished from direct assignment to rate classes. The Utilities' ECOSS does the latter in many cases.

Third, while Mr. Glahn use the terms "facilities charge" and "metering surcharge," (Proposed Order at 197; GCI Ex. 6.0 REV, at 5), that oversimplifies what direct assignment would entail. It is not a matter of taking the test year dollars in Account No. 385 and dividing by the number of customers receiving service from Account No. 385 facilities. It would mean calculating a specific rate for each customer whose facilities have been recorded in Account No. 385. As the Proposed Order correctly stated, the current customers to whom Peoples Gas would assign these costs are in different service classifications. The customers may change service classifications. Peoples Gas may retire or replace the Account No. 385 facilities included in the test year. There are many variables at work. Peoples Gas would need to develop a method of calculating customer-specific charges and draft associated tariff language for its tariff. The tariff language would need to accommodate the different service classifications under which customers are served and ensure that customers do not pay twice for metering, regulator and service costs. Neither the Proposed Order, nor Mr. Glahn described a method for calculating these customer-specific charges.

For these reasons, direct assignment, to individual customers, of Account No. 385 costs, for the purpose of creating customer-specific charges, is not appropriate. See Exception No. 23 in the NS-PGL Exceptions.

IX. <u>RATE DESIGN</u>

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

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

<u>Exception No. 24</u>

The Proposed Order accepted Staff's proposed method, with the Utilities' proposed corrections, for recovering gas cost-related uncollectible expenses from sales and transportation customers. Proposed Order at 217. The Utilities do not except to that conclusion, but they seek clarification on one point. Also, the Proposed Order notes that the AG made untimely arguments on this issue, and the Proposed Order stated that "[t]o complete our analysis, we await the Briefs on Exceptions." *Id*.

Clarification

The description of Staff's method references Staff Ex. 19.0, Sched. 19.3-NS and 19.3-PG. Proposed Order at 215. However, those schedules address only Service Classification ("S.C.") Nos. 1N, 1H and 2. The Utilities, in response to Staff arguments, proposed to include Peoples Gas S.C. No. 4 in the allocation of uncollectible expense. Amen Reb., NS-PGL Ex. RJA-2.0, at 14. Staff did not contest this proposal. It would be useful if the Proposed Order clarified the service classifications included in this allocation.

AG's Reply Brief Comments

The AG's belated criticisms, summarized in detail on page 216 of the Proposed Order, of the method for addressing S.C. No. 1 rate design in the absence of Rider UBA are unsupported and should be rejected.

The AG's first point pertains to the amount of dollars to be allocated and is unrelated to the underlying rate design issue. The final revenue requirement will determine the dollars that need to be allocated, and the Utilities' proposals can accommodate the Commission's decision.

The AG's second point criticizes the proposed bifurcation of S.C. No. 1 into heating and non-heating service classifications. The Proposed Order comprehensively and correctly addressed that issue at pages 238-239.

The AG's third point, addressing the allocation of the uncollectible expense for S.C. No. 1H between the first and second blocks, 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 they proposed for the allocation of remaining costs not recovered through the customer charge. Grace Dir., PGL Ex. VG-1.0, at 14; Grace Dir., NS Ex. VG-1.0, at 12; *also see* Grace Sur., NS-PGL Ex. VG-3.0 REV, at 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. The Staff addressed adjustments for the gas cost portion of the uncollectible expense but not at the level of detail required for allocation between distribution charge rate blocks, and the AG made no proposals for determining distribution charges. Only the Utilities proposed specific methods for easily and objectively determining distribution charges, whatever revenue requirement is approved. *See, e.g.*, Grace Sur., NS-PGL Ex. VG-3.0 REV, at 5, 18, 19, 22.

The AG's fourth point, contending that the uncollectible expense proposal sends the wrong price signal, is misplaced in this context. The Utilities proposed a consistent design of the S.C. No. 1H distribution charges. If the AG has concerns about price signals associated with the front block, those concerns are more properly addressed in the larger context of the S.C. No. 1 rate design. The Proposed Order comprehensively and correctly concluded that "the Utilities' proposals represent the most reasoned approach to establishing just and reasonable rates for small residential heating and non-heating customers." Proposed Order at 239.

The Proposed Order adequately addressed the AG's arguments in the context of considering various S.C. Nos. 1N and 1H proposals. The Proposed Order thoroughly vetted the AG's incomplete rate design proposals. This part of the Proposed Order is addressing the development of sales and transportation customers' distribution charges in the absence of Rider UBA, and the AG's arguments are not specific to this rate design issue. The Staff's proposal, with the Utilities' corrections and the clarification requested above, is reasonable and should be adopted if the Commission does not accept Rider UBA. See Exception No. 24 in the NS-PGL Exceptions.

C. <u>Service Classification Rate Design</u>

2. <u>Contested Issues</u>

a. <u>Peoples Gas Service Classification Nos. 1N and 1H</u>
b. <u>North Shore Service Classification Nos. 1N and 1H</u>

<u>Exception No. 25</u>

The Proposed Order thoroughly and accurately summarized the complex record of rate proposals and arguments pertaining to the Utilities' S.C. Nos. 1N and 1H. The Proposed Order also correctly concluded that "the Utilities' proposals represent the most reasoned approach to establishing just and reasonable rates for small residential heating and non-heating customers." Proposed Order at 239. However, unlike the other service classifications, there were many proposals, counterproposals and alternatives offered for S.C. Nos. 1N and 1H. The Utilities suggest that greater specificity concerning the specific rate designs adopted would be useful.

In particular, the Utilities propose language for a summary sentence in the Commission Analysis and Conclusions section to state specifically that the Commission adopts: the Utilities' proposed bifurcation of S.C. No. 1 into heating and non-heating service classifications, including the Utilities' method of assigning customers to these new classifications; the Utilities' proposed customer charges; 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 Equal Percentage of Embedded Cost method in connection with allocating the rate increase among S.C. Nos. 1N, 1H and 2; and setting North Shore's service classifications at cost. See Exception No. 25 in the NS-PGL Exceptions.

X. TRANSPORTATION ISSUES

C. Large Volume Transportation Program

4. Injection, Withdrawal and Cycling Limits

Exception No. 26

The Proposed Order at 265 should be modified to provide that North Shore's seasonal injection target applicable to large volume transportation customers should be reduced from 85% to 75% of the customer's Allowable Bank if the Commission grants Exception No. 27, *infra*. While North Shore continues to believe its originally proposed 85% target is justified by the evidence in the record, North Shore recognizes that its large volume transportation customers are concerned about the impact of this target in conjunction with the daily injection and delivery limits proposed by North Shore. In order to address those concerns of the large volume transportation customers on the interplay between these two requirements, North Shore believes that its seasonal injection target of 85% should be reduced to 75% if the Commission grants Exception No. 27, *infra*.

Exception No. 27

The Proposed Order, at 266, errs by rejecting any of the daily injection and delivery limits proposed by the Utilities. While the Proposed Order readily acknowledges the serious and complex responsibilities the Utilities bear with respect to management of their systems, it nevertheless finds that it is not apparent that the Utilities' challenges would be appreciably heightened if the nomination caps for Riders FST and SST were defined by MDQ, on a year-round basis. The Proposed Order ignores the fact that Vanguard and CNE-Gas, who are significant transportation suppliers under both Rider FST and Rider SST, are willing to accept limitations on their ability to nominate gas under those riders. This fact alone shows that these two suppliers have some appreciation for the challenges faced by the Utilities and that some sort of nomination caps for these riders other than MDQ during the injection season are justified in light of those challenges. The harm to the Utilities' sales customers from the absence of any nomination caps on large volume transportation customers, and the unfairness of the harm, is explained in NS-PGL witness Mr. Zack's Rebuttal Testimony. NS-PGL Ex. TZ-2.0, at 11-13, 29. In not explaining why reasonable limitations on Riders FST and SST nominations are inappropriate during the injection season, the Proposed Order gives no weight to the record and is therefore unreasonably drawn.

The Proposed Order also effectively ignores the fact that the Utilities modified their proposals concerning their large volume transportation programs substantially and from time to time during the course of these proceedings in response to objections raised by large volume transportation customer suppliers such as CNE-Gas and Vanguard. The Utilities abandoned their original proposal to eliminate Rider FST in response to those objections. Zack Sur. NS-PGL Ex. TEZ-3.0 REV, at 4-8. The Utilities also abandoned their proposals to impose daily limits on injections and withdrawals. *Id*., at 8-10. In their place, the Utilities proposed a less restrictive limitation on Rider FST daily deliveries and Rider SST daily injections. In response to these concessions by the Utilities, CNE-Gas and Vanguard have indicated their willingness to accept the Utilities' proposals to limit the ability to nominate gas under Riders FST and SST during the injection season. Thus, CNE-Gas and Vanguard give the Utilities credit for the Utilities' positive responses to their concerns, but the Proposed Order would not give the Utilities any such acknowledgement or recognize the *quid pro quo* inherent in the Utilities' responses. The Proposed Order also fails to recognize that the delivery restrictions imposed by the Utilities from time to time, which the Proposed Order recognizes as being necessary in order to permit the

Utilities to manage their systems, could be fewer in number and duration, and less disruptive to large volume transportation program suppliers (who would have more certainty in their own planning processes), if the Utilities were able to implement pre-set formulae to govern deliveries. Zack Reb., NS-PGL Ex. TZ-2.0, at 43.

In light of the foregoing, the Commission should find that transportation customers taking service under Rider FST of either Utility should be limited to MDN during the months of April through October of each year, and that transportation customers taking service under Rider SST of either Utility also should be limited to MDN, as defined in Rider FST, during the months of April through October of each year.

XII. UNION PROPOSALS

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

Exception No. 28

The Proposed Order (at 297-298) directs, with particularity, an audit related to staffing and repairs. The Utilities believe that this recommendation should not be adopted, as discussed in the following two subsections, and that the Proposed Order, therefore, should be revised as set forth in Exception No. 28 in the NS-PGL Exceptions.

a. The Proposed Audit Is Not Necessary

The Proposed Order, like Local 18007, identifies the repair of one particular leak – one in which no one was hurt and there is no reasonable grounds to think that safety was in any way compromised as the grounds for a full audit of every repaired leak for the past several years. The Utilities ask the Commission not to adopt this recommendation.

Audits are time-consuming and expensive, so understandably, the Commission is to order them only when the facts truly warrant it. The applicable standard for whether to order an audit is set forth in Section 8-102 of the Act, 220 ILCS 5/8-102. The Commission is to order an audit "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." *Id*. The record here does not contain such grounds. Nowhere in the record is evidence of employees or customers involved in accidents, of buildings being evacuated due to the failure of temporary repairs, or any other evidence of an actual safety issue.

What the record does contain is a single example of a situation where Peoples Gas did not make a permanent repair for a month after a temporary repair had been put into place. The proposed order erroneously relied on this one incident to justify a full audit. The Sacred Heart Hospital leak does not meet the test of Section 8-102, for several reasons. First, the Proposed Order confuses a potentially dangerous problem – a serious Class 1 leak – with an actual safety problem involving the repair. Temporary repairs, though they need subsequent follow-up, were not shown to be unsafe. Doerk, Tr. at 230; 231; 234. The record is clear that Peoples Gas applied an effective temporary repair and stopped the leak before anyone was hurt. There is no allegation that Peoples Gas was slow to respond or that, through any fault of the Utility, customers were endangered. Second, this situation was clearly not a typical one, from which broader lessons can be inferred. The customer was a hospital that operates 24 hours a day. Fixing the leak permanently required shutting gas off to the entire hospital, and that took a few weeks to schedule. Doerk Reb., NS-PGL Ex. ED-2.0, at 4. Third, and of particular importance to Local 18007's case, the reason for the delay in applying a permanent repair was not a lack of supervisory personnel, but scheduling problems with the customer. *Id* at 81-86.

The Proposed Order accuses Peoples Gas of "trivializing" Local 18007's one example. It was not Peoples Gas' intent to belittle the seriousness of a Class 1 leak. However, when the circumstances of the company's handling of this leak are examined, it does not constitute a bona fide example of misconduct or being lax on safety. It does not give the Commission reasonable grounds to believe that an audit is necessary to assure safe service. See the alternate language Exception No. 28 in the NS-PGL Exceptions.

b. The Details of the Audit Need Further Discussion and Definition

The record in this docket does not contain enough detail to specify the parameters of a useful audit. Therefore, if, notwithstanding Peoples Gas' exceptions detailed above, the Commission decides to require Peoples Gas to conduct an audit, the Commission should not establish the specific parameters for the audit in its order in this proceeding. The Proposed Order itself notes that there was a need to "sharpen the focus of the Local's audit request" as it related to work order response times and, similarly, the Local's audit request with respect to staffing "also needs narrowing". However, although well-intentioned, the Proposed Order would require the reporting of specific statistics which were never addressed in the evidentiary record of this proceeding. Therefore, the evidentiary record does not support a finding that these specific statistics would be meaningful or even exist (and indeed, some do not). The Proposed Order seems to acknowledge this when it encourages Peoples Gas and the Local, "as the entities most familiar with the pertinent subject matter…to expand or reorganize—by mutual agreement—the focus of the audit to make its results as useful as is practicable". However, there is an additional entity that has expertise in this subject and that is the Commission Staff, specifically the Natural Gas Pipeline Safety Section. Accordingly, Peoples Gas recommends that, if an audit is required, the Proposed Order be revised to eliminate the request for specific statistics and, instead, direct

Peoples Gas to work with the Commission's Pipeline Safety Section and Local 18007 to develop the appropriate focus of the audit, including the statistics to be reported. See Exception No. 28 in the NS-PGL Exceptions.

XIII. FINDING AND ORDERING PARAGRAPHS

Exception No. 29

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, discussed above, but also the quantitative impacts of Exception Nos. 5 through 14, discussed above.

In addition, Appendix A should be corrected due to an error in the split of Total Operating Revenues (not including PGA Revenues and Coal Tar Revenues) between Base Rate Revenues and Other Revenues. Appendix A on page 1 in Column (i) shows the Total Operating Revenues of $453,457,000 split between $437,769,000 of Base Rate Revenues and $15,688,000 of Other Revenues. That is incorrect. The $453,457,000 should be split between Base Rate Revenues of $436,526,000 and Other Revenues of $16,931,000. The error is due to Columns (e) and (h) of page 1. In Column (e), the revenue increase is shown entirely as an increase in Base Rate Revenues. There is an increase in Other Revenues, however, with the increase in Base Rate Revenues. Specifically Other Revenues from FERC Account 487, forfeited discounts, increases and decreases with increases and decreases in Base Rate Revenues. For Column (e), the increase in Other Revenues should be $1,491,000, while the increase in Base Rate Revenues should be $97,508,000. Similarly for Column (h), the decrease in Other Revenues should be ($248,000) and the decrease in Base Rate Revenues should be ($35,884,000). All of the figures in this paragraph assume the other existing figures in Appendix A, including the incorrect figures relating to Peoples Gas' CWC in rate base discussed earlier. To the extent that the Commission corrects the incorrect figures relating to Peoples Gas' CWC in rate base and adopts Peoples Gas' other Exceptions relating to rate base, operating expenses, and ROE, then Appendix A will need to be revised accordingly to correctly set forth the impacts, including the impacts on the split of Total Operating Revenues between Base Rate Revenues and Other Revenues. See Exception No. 30 in the NS-PGL Exceptions.

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, discussed above, but also the quantitative impacts of Exception Nos. 5 through 14, discussed above.

In addition, Appendix B should be corrected due to an error in the split of Total Operating Revenues (not including PGA Revenues and Coal Tar Revenues) between Base Rate Revenues and Other Revenues. Appendix A on page 1 in Column (i) shows the Total Operating Revenues of $62,646,000 split between $61,007,000 of Base Rate Revenues and $1,639,000 of Other Revenues. That is incorrect. The $62,646,000 should be split between Base Rate Revenues of $60,915,000 and Other Revenues of $1,731,000. The error is due to Columns (e) and (h) of page 1. In Column (e), the revenue increase is shown entirely as an increase in Base Rate Revenues. There is an increase in Other Revenues, however, with the increase in Base Rate Revenues. Specifically Other Revenues from FERC Account 487, forfeited discounts, increases and decreases with increases and decreases in Base Rate Revenues. For Column (e), the increase in Other Revenues should be $109,000, while the increase in Base Rate Revenues should be $4,136,000. Similarly for Column (h), the decrease in Other Revenues should be ($17,000) and the decrease in Base Rate Revenues should be ($5,234,000). All of the figures in this paragraph assume the other existing figures in Appendix B, including the incorrect figures relating to North Shore's CWC in rate base discussed earlier. To the extent that the Commission corrects the incorrect figures relating to North Shore's CWC in rate base and adopts North Shore's other Exceptions relating to rate base, operating expenses, and ROE, then Appendix B will need to be revised accordingly to correctly set forth the impacts, including the impacts on the split of Total Operating Revenues between Base Rate Revenues and Other Revenues. See Exception No. 31 in the NS-PGL Exceptions.

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The Peoples Gas Light and Coke Company

	Utility			Staff		Average w/o
	DCF	CAPM	Risk Premium	DCF	CAPM (Risk Premium)	Utility Risk Prem. and Staff DCF
Unadjusted	9.01%	10.79%	11.25%	8.23%	11.34%	10.38%
Financial Leverage Adjustment	0.52%	1.06%				
Model adjusted for financial leverage	9.53%	11.85%	11.25%	8.23%	11.34%	10.91%
Floatation Costs	0.19%	0.19%	0.19%			
Model adjusted for financial leverage and floatation costs	9.72%	12.04%	11.44%	8.23%	11.34%	11.03%
Financial risk adjustment				-0.09%	-0.09%	
Models with Adjustments	9.72%	12.04%	11.44%	8.14%	11.25%	11.00%
Average of totals/Recommendations			11.06%		9.70%	

North Shore Gas

	Utility			Staff		Average w/o
	DCF	CAPM	Risk Premium	DCF	CAPM (Risk Premium)	Utility Risk Prem. and Staff DCF
Unadjusted	9.01%	10.79%	11.25%	8.23%	11.34%	10.38%
Financial Leverage Adjustment	0.52%	1.06%				
Model adjusted for financial leverage	9.53%	11.85%	11.25%	8.23%	11.34%	10.91%
Floatation Costs	0.19%	0.19%	0.19%			
Model adjusted for financial leverage and floatation costs	9.72%	12.04%	11.44%	8.23%	11.34%	11.03%
Financial risk adjustment				-0.29%	-0.29%	
Models with Adjustments	9.72%	12.04%	11.44%	7.94%	11.05%	10.94%
Average of totals/Recommendations			11.06%		9.50%	