STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

NORTH SHORE GAS COMPANY	:	
	:	No. 09-0166
Proposed General Increase In Rates For Gas Service.	:	and
	:	No. 09-0167
THE PEOPLES GAS LIGHT AND COKE COMPANY	:	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

North Shore Gas Company ("North Shore" or "NS") and The Peoples Gas Light and Coke Company ("Peoples Gas" or "PGL") (together, "the Utilities"), in accordance with the schedule set in the Administrative Law Judges' (the "ALJs") Proposed Order of November 6, 2009 (the "Proposed Order" or "ALJPO"), and Section 200.830 of the Rules of Practice of the Illinois Commerce Commission (the "Commission" or "ICC"), 83 Ill. Adm. Code § 200.830, submit this Brief on Exceptions along with a separately filed Exceptions to the Proposed Order (the "NS-PGL Exceptions") that contains proposed revised Order language in black-lined format.

INTRODUCTION AND SUMMARY

The Proposed Order's recommendations on most subjects are consistent with the evidence and the law, including its rulings on most of the revenue requirement issues, its approval of a modified version of Peoples Gas' infrastructure rider ("Rider ICR"), and its rulings on most of the rate design, cost of service, and tariff (terms of service) issues.

However, the Proposed Order recommends figures for each utility's total "test year" costs of service to be recovered through base rates (their "revenue requirements") that fall short of their actual costs of service. The impact of those errors is only magnified because the Utilities already have sharply reduced their proposed revenue deficiencies (the amounts by which their revenues under existing rates under-recover their revenue requirements, *i.e.*, their proposed rate increases)[1] over the course of these cases. Peoples Gas' initial forecast for 2010 (the uncontested test year in these cases) yielded a revenue deficiency of $161,920,000, but, by its surrebuttal testimony, it had reduced that figure by $48,742,000, or over 30%, to $113,178,000.[2] Similarly, North Shore reduced its initial forecast of $21,986,000 by $3,865,000, or nearly 18%, to $18,105,000.[3] The Utilities' much lower final revised rate increase requests in their surrebuttal reflect (1) the extraordinary steps they have taken to control their costs in the current economic environment plus (2) their acceptance in whole or in part (in many instances in an effort to narrow the issues) of a host of adjustments proposed by the Commission's Staff ("Staff") or intervenors (including updated lower natural gas costs).[4]

By contrast, the Proposed Order (at 277) recommends rate increases of only $66,248,000 for Peoples Gas and $13,354,000 for North Shore. Those levels of rate increases will not allow the Utilities to recover their real costs of service, to the detriment of all. The following chart illustrates the above figures.

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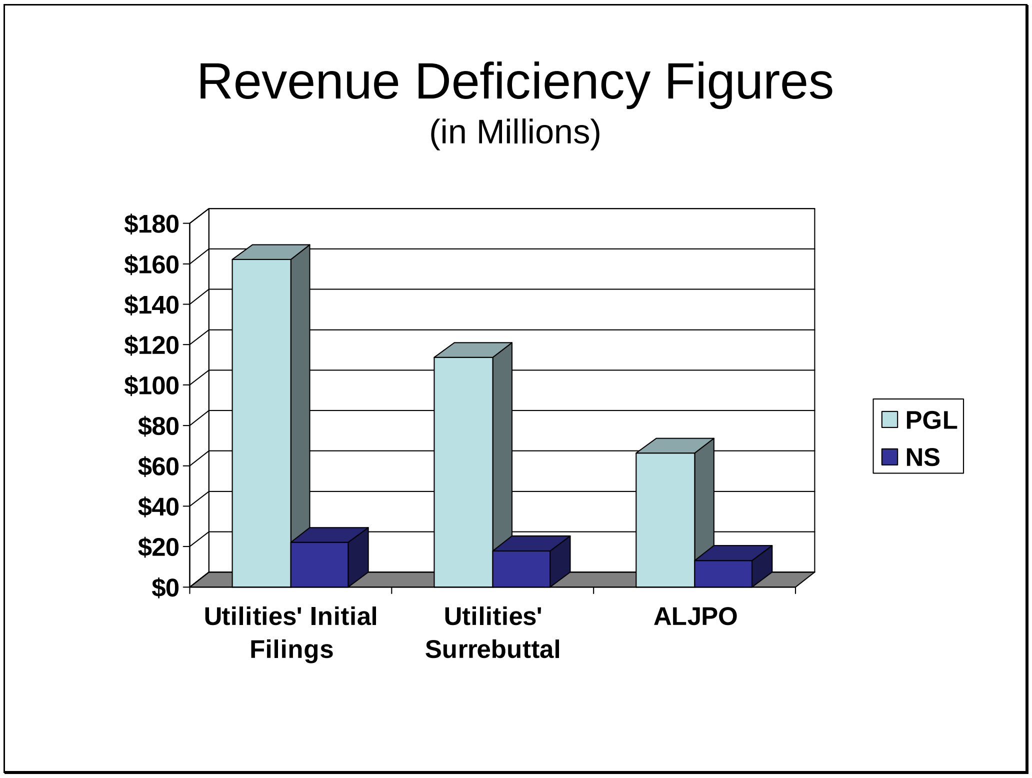
[1] A utility's revenue deficiency and its rate increase amount are the same number. As noted above, a utility's revenue deficiency equals its revenue requirement minus its revenues under existing rates. Thus, the revenue deficiency is the amount by which rates must be increased to allow the utility the opportunity to fully recover its costs of service.

[2] PGL Exhibit ("Ex.") SM-1.1 at Schedule ("Sched.") C-1, line 1; PGL Ex. SM-3.1 at Sched. C-1, line 1.

[3] NS Ex. SM-1.1 at Sched. C-1, line 1; PGL Ex. SM-3.1 at Sched. C-1, line 1.

[4] *E.g.*, Schott Direct ("Dir."), PGL Ex. JFS-1.0 Rev. at 4:81-86; Schott Dir., NS Ex. JFS-1.0 Rev. at 4:67-72; Moy Rebuttal ("Reb."), NS-PGL Ex. SM-2.0 at 2:31-33, 2:37-39, 3:67 - 5:111; NS-PGL Ex. SM-2.2N at Sched. C-2; NS-PGL Ex. SM-2.2P at Sched. C-2; Schott Reb., NS-PGL Ex. JFS-2.0 at 6:130 - 7:141; NS-PGL Ex. JFS-2.1 (list of adjustments accepted in whole or in part); Johnson Reb., NS-PGL Ex. BAJ-2.0 2Rev. at 22:467-469; Moy Surrebuttal ("Sur."), NS-PGL Ex. SM-3.0 Rev. at 2:35-42, 3:46-49, 4:75-84; NS-PGL Ex. SM-3.2N at Sched. C-2; NS-PGL Ex. SM-3.2P at Sched. C-2; Schott Sur., NS-PGL Ex. JFS-3.0 at 6:121-125; NS-PGL Ex. JFS-3.1 (list of adjustments accepted in whole or in part).



As a result, the Proposed Order should be adopted in most respects, but its recommendations on the three largest revenue requirement issues (rates of return on common equity, Peoples Gas' pension asset, and incentive compensation costs), and on certain other revenue requirement, cost of service, rate design, and tariff issues, should be revised based on the evidence in the record and the applicable law.[5]

The remainder of this Introduction and Summary briefly overviews the two basic legal principles that govern these cases; the cost shortfall drivers of the Utilities' revenue deficiencies; the three largest revenue requirement issues; Rider ICR; and the rate design, cost of service, and tariff issues.

[5] The Utilities disagree with, but, in order to narrow the issues, are not filing Exceptions to the Proposed Order's recommendations on the subjects of non-union base wages, advertising expenses, and costs of long-term debt, as noted further below.

Governing Legal Principles. In a rate case, the Commission has a legal duty to set rates that allow the public utility the opportunity to recover fully its prudent and reasonable costs of service, including a fair return on its investment, *i.e.*, to recover its revenue requirement. A public utility has the right to such rates under long-established federal and Illinois constitutional law.[6] A public utility also has the right to such rates under Illinois ratemaking law.[7] Thus, Illinois courts have reversed the Commission when it incorrectly excluded a public utility's costs from recovery through rates.[8]

In a rate case, the Commission also is required to set just and reasonable rates. 220 ILCS 5/9-201(c). The rates must be just and reasonable to the utility, its stockholders, and customers. *E.g., Bus. and Prof. People for the Pub. Interest v. Illinois Commerce Comm'n*, 146 Ill. 2d 175, 208 (1991) ("*BPI II*").

The principle that the Commission must establish rates that allow a utility the opportunity to recover fully its costs of service is in the long-term interests of customers as well as the utility. Large cost recovery shortfalls increase the utility's costs of capital over time and are incompatible with sustaining a utility that is able to provide safe, adequate, and reliable service

[6] *E.g., Duquesne Light Co. v. Barasch*, 488 U.S. 299, 309-310 (1989); *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 622 (1944); *Bluefield Water Works & Improvement Co. v. Public Service Comm'n of the State of West Virginia*, 262 U.S. 679, 693 (1923); U.S. Const., amend. V, XIV (due process and takings clauses); Ill. Const., art. I, §§ 2, 15 (same).

[7] *E.g., Commonwealth Edison Co. v. Illinois Commerce Comm'n,* 322 Ill. App. 3d 846, 849 (2d Dist. 2001) ("*ComEd*") (citing *Citizens Utilities Co. v. Illinois Commerce Comm'n*, 124 Ill. 2d 195, 200 (1988) ("*Citizens Utilities*")). *See also, e.g., Citizens Utility Board v. Illinois Commerce Comm'n*, 166 Ill. 2d 111, 121 (1995) ("*CUB*") (involving costs recovered under a rider rather than through base rates).

[8] *E.g., Illinois Power Co. v. Illinois Commerce Comm'n,* 339 Ill. App. 3d 425, 435-443 (5th Dist. 2003) (exclusion from rate base); *ComEd*, 322 Ill. App. 3d at 850 (same); *Citizens Utilities*, 124 Ill. 2d at 203-214 (same); *see also, e.g., CUB*, 166 Ill. 2d at 121 (exclusion of certain operating expenses from recovery under rider); *Monarch Gas Co. v. Illinois Commerce Comm'n,* 261 Ill. App. 3d 94, 100-101 (5th Dist. 1994) (same).

over the long term. *E.g.,* Schott Dir., PGL Ex. JFS-1.0 Rev. at 4:74-80; Schott Reb., NS-PGL Ex. JFS-2.0 at 6:112-129; Schott Dir., NS Ex. JFS-1.0 Rev. at 3:60-66.

Background on the Cost Shortfall Drivers of the Utilities' Revenue Deficiencies. Although the Commission approved new rates for the Utilities in February 2008 (using an adjusted fiscal year 2006 test year ending September 30, 2006), the Utilities did not recover their costs of service even in 2008, and they are faced with increased costs, and thus larger cost recovery shortfalls, despite their having taken extraordinary cost control measures as described above. For example:

- The Utilities, under existing rates, are significantly under-recovering their operating expenses. Their existing rates set in February 2008 are based on annual operating expenses before income taxes of $325,582,000 for Peoples Gas and $42,895,000 for North Shore.[9] Their final revised operating expenses before income taxes in 2010, however, are forecasted to be $403,231,000 and $59,946,000, respectively.[10] Those shortfalls make up the bulk of the Utilities' test year cost recovery shortfalls (their revenue deficiencies).
- The Utilities, under existing rates, also are significantly under-recovering their costs of capital. In February 2008, the Commission set rates reflecting approved overall rates of return of 7.76% and 7.96% for Peoples Gas and North Shore, respectively.[11] In 2010, under existing rates, Peoples Gas will be recovering an

[9] *In re North Shore Gas Co., et al.*, ICC Docket Nos. 07-0241/07-0242 Cons. (Order Feb. 5, 2008) ("*Peoples 2007*") at Appendix ("App.") A, p. 1., line 19, col. (i), and App. B, p. 1, line 19, col. (i).

[10] NS-PGL Ex. SM-3.1P at Sched. C-1, col. [I] (sum of lines 15 through 18); NS-PGL Ex. SM-3.1N at Sched. C-1, col. [I] (sum of lines 15 through 18).

[11] *Peoples 2007* at App. A, p. 1., line 26, and App. B, p. 1, line 26.

overall rate of return of just 4.00%, and North Shore will be recovering an overall rate of return of just 3.04%,[12] even though their costs of capital have increased significantly with the financial crisis of Fall 2008 and the subsequent recession.

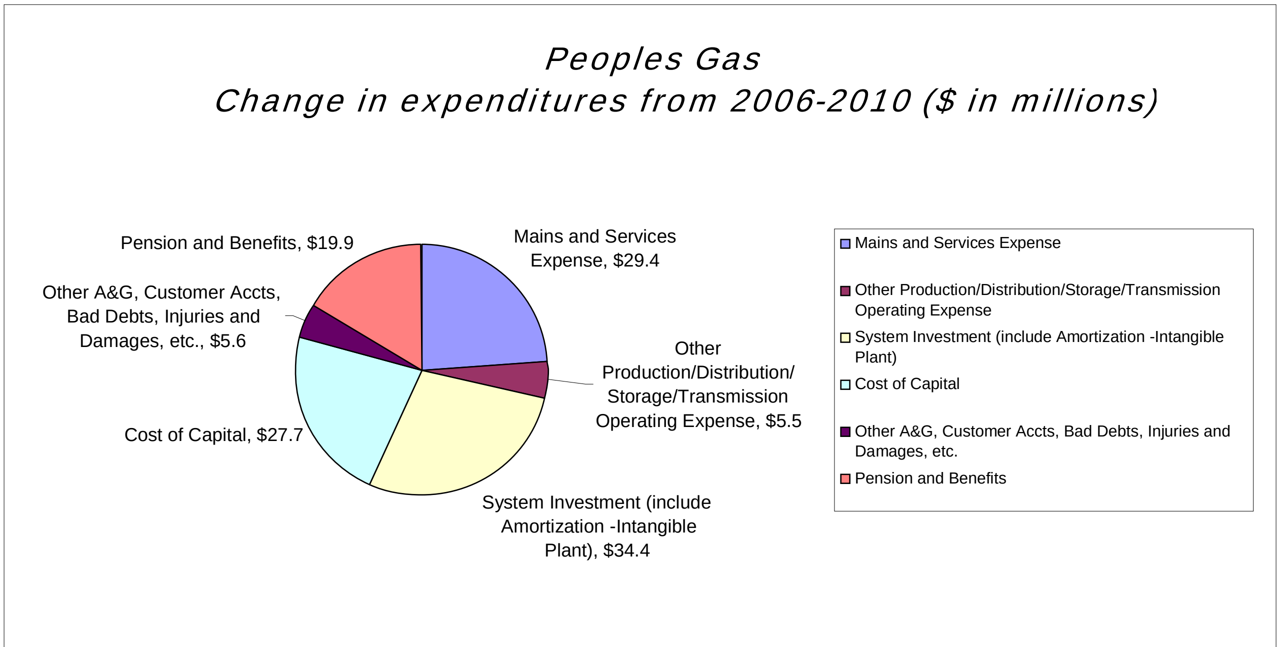
- These shortfalls in the Utilities' recovery of their costs of equity are having a significant impact on their earnings. In 2008, despite new rates that were intended to result in an authorized rate of return on common equity ("ROE") of 9.99%, North Shore earned an ROE of just 6.66% (Schott Dir., NS Ex. JFS-1.0 Rev. at 11:227-229), and as of the filing it was forecast to earn an ROE of just 1.1% in 2010 (Johnson Dir., NS Ex. BAJ-1.0 at 4:69). In 2008, despite new rates that were intended to result in an authorized ROE of 10.19%, Peoples Gas earned an ROE of just 5.64% (Schott Dir., PGL Ex. JFS-1.0 Rev. at 12:248-250), and as of the filing it was forecast to earn an ROE of just 0.3% in 2010 (Johnson Dir., PGL Ex. BAJ-1.0 at 4:70).

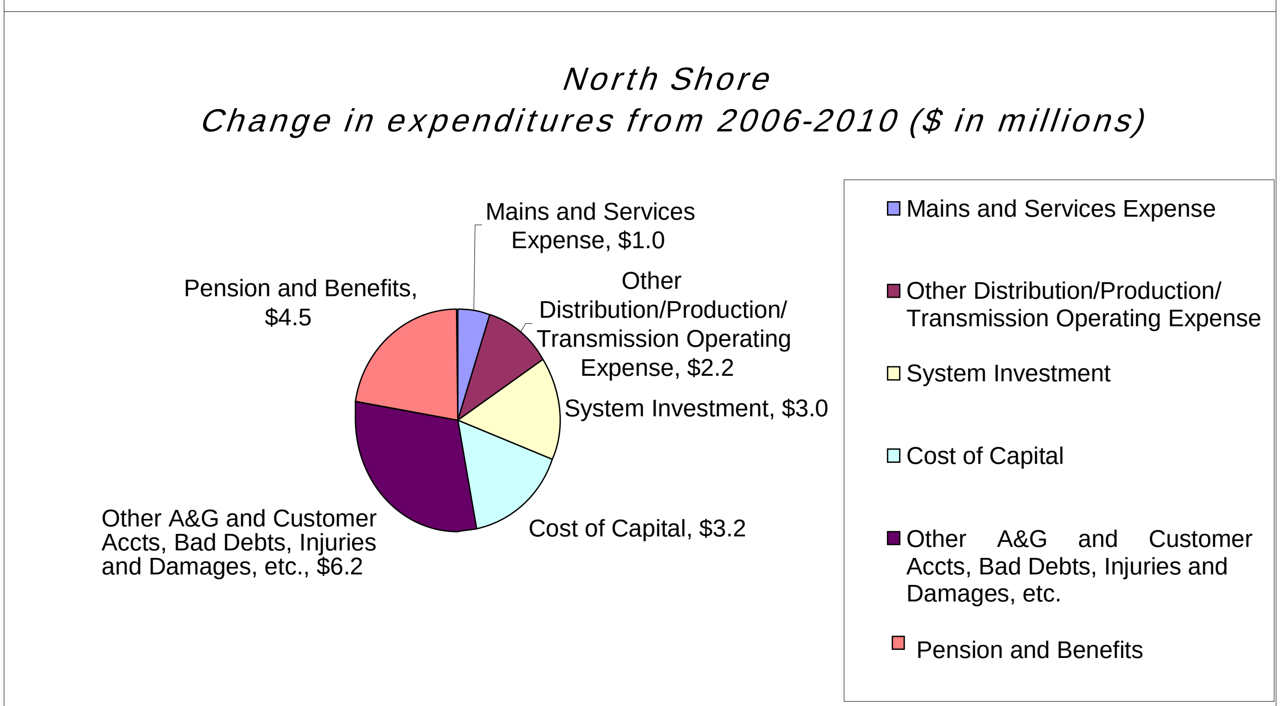
Utilities witness James Schott, Vice President - Regulatory Affairs, in his direct testimony, presented a detailed analysis of the drivers of the Utilities' cost increases. Schott Dir., NS Ex. JFS-1.0 Rev. at 8:159 - 11:224; Schott Dir., PGL Ex. JFS-1.0 Rev. at 9:179 - 12:245. Mr. Schott, in his rebuttal, presented updated analyses of the drivers of the Utilities' cost increases that reflected various revisions, including the extraordinary cost control measures they had adopted. Schott Reb., NS-PGL Ex. JFS-2.0 at 10:205 - 11:214.

As to Peoples Gas, increased investments in its system and increased mains and services expenses are the primary drivers of the costs increases, followed next by its increased costs of capital. For North Shore, the net increase in a group of Administrative and General and

[12] NS-PGL Ex. SM-3.1P at note (c); NS-PGL Ex. SM-3.1N at note (c).

customer-related expenses is the primary driver, followed by increased pensions and benefits expenses, increased costs of capital, and increased investments in its system. The drivers are quantified in the following charts from page 11 of Mr. Schott's rebuttal testimony.





<u>Costs of Common Equity</u>. The Utilities' presented substantial evidence that their cost of common equity have increased since their last rate cases, which were decided before the financial crisis and subsequent economic recession. The Proposed Order, however, recommends a <u>decrease</u> in Peoples Gas' authorized ROE from 10.19% to 9.93%, and only the smallest of increases for North Shore, from 9.99% to 10.03%. ALJPO at 130. These proposed returns are unrealistically low. In fact, they would represent the second and third lowest returns authorized by this Commission for a natural gas utility since at least 1972.

Capital costs have increased since the financial crisis began in late 2008. This is a period of risk aversion in the capital markets, in which investors must receive higher – not record low – returns on their equity investments. In order to adopt the Proposed Order's recommended ROEs, the Commission would have to conclude that the Utilities have the lowest cost of equity today than all but one natural gas utility in Illinois has in almost 40 years. Such a conclusion would bear no relation to reality.

The Proposed Order reaches this unrealistic result by including a suspect Staff estimate of equity cost based on a version of the familiar Discounted Cash Flow ("DCF") model that appears to have been adopted for the purpose of reducing utility authorized returns. The Proposed Order also adopts all of Staff's adjustments to the market-based cost of equity determined by the financial models, including a fatally flawed "financial risk" adjustment and duplicative adjustments for the effect of riders on the Utilities' financial risk.

As discussed below, although the Utilities continue to maintain that their cost of equity is their final revised figure of 11.87% ("Alternative 1"), they also offer an alternative, compromise approach that bases their authorized ROEs on (1) Staff's and the Utilities' results using the Commission's traditional "constant growth" DCF model, (2) Staff's and the Utilities' "CAPM"

(Capital Asset Pricing Model) results, and (3) either Staff's financial risk adjustment or Staff's rider adjustments but not both because they are duplicative. In "Alternative 2A," the Commission rejects the financial risk adjustment and accepts the rider adjustments. In "Alternative 2B," the Commission accepts the financial risk adjustment and rejects the rider adjustments. The following table shows the alternative results of this compromise approach:

UTILITIES' COMPROMISE ROE RESULTS					
	Market ROE[13]	Financial Risk Adj	VBA Adj	UEA Adj	Final
PGL Alt 2A[14]	10.81	0	-0.10	-0.10	10.61
PGL Alt 2B	10.81	-0.30	0	0	10.51
NS Alt 2A	10.81	0	-0.10	-0.10	10.61
NS Alt 2B	10.81	-0.20	0	0	10.61

Under their compromise approach, the Utilities' costs of equity would be in the midrange of recent authorized returns for companies that compete with the Utilities in the capital markets. Such returns would represent "mainstream" results of the type discussed by the Utilities' witness Mr. Fetter.

Peoples Gas Pension Asset. The Proposed Order removes Peoples Gas' pension asset and North Shore's pension liability from rate base, as did the Commission's Order in *Peoples 2007*. ALJPO at 36-37. The Proposed Order is based on the theory that customers paid for the pension asset, and states in part: "Although the Utilities state that the pension asset was created

[13] Market ROE based on average of the Utilities' and Staff's unadjusted constant growth DCF results ((10.67 + 11.76)/2 = 11.215) and CAPM results ((10.86 + 9.95)/2 = 10.405).

[14] For Peoples Gas, the Rider ICR adjustment would be made to the ROE factor only under "Alternative 2A".

with shareholder funds, no evidentiary support was provided." *Id*. at 37. That is incorrect both factually and legally, as discussed further below. The Proposed Order's own recitation of Peoples Gas' evidence on this subject demonstrates that there is detailed evidence that the pension asset was paid for by its shareholders, not by customers. *See id*. at 25-29. Moreover, legally, utility customers pay for service, not for the property used to render it. *Board of Public Utility Commissioners, et al. v. New York Tel. Co.*, 271 U.S. 23 (1926).

The Proposed Order relies on its incorrect finding that customers paid for the pension asset as its sole basis for distinguishing the Commission's decision to allow a utility a rate of return based on its cost of debt on its pension contribution in *In re Commonwealth Edison Co.*, ICC Docket No. 05-0597 (Order on Rehearing Dec. 20, 2006), *aff'd, Commonwealth Edison Co. v. Illinois Commerce Comm'n, et al.*, Nos. 2-06-0184 Cons., 2009 WL 3048420 (Ill. App. Ct. 2d Dist. Sept. 17, 2009) ("*ComEd 2005 Appeal*"). *See* ALJPO at 36-37. Thus, the Proposed Order's conclusion (at 37) that the Commission's decision in the 2005 ComEd rate case supports allowing Peoples Gas no return on its pension asset is incorrect.

In addition, the Proposed Order pays no heed to Peoples Gas' point that the Commission, in the interests of employees and customers as well as utilities, should encourage adequate pension plan funding, not send signals to do less. In its 2005 ComEd rate case Order on Rehearing, the Commission acknowledged that "the [pension] contribution assisted in providing adequate funding for the retirement obligations of ComEd's workforce and … ComEd's customers saved $30.2 million as a result of the contribution." *In re Commonwealth Edison Co.*, ICC Docket No. 05-0597 (Order on Rehearing Dec. 20, 2006), at 28.

Finally, the Proposed Order also disregards the impact of this disallowance on the utility's actual overall rate of return and ROE. Disallowance would effectively reduce Peoples Gas' overall rate of return by roughly 67 basis points and its ROE by roughly 120 basis points.[15]

<u>Incentive Compensation Costs</u>. The Proposed Order recommends adoption of nearly all of Staff's proposed adjustments to the Utilities' incentive compensation costs. Those adjustments cumulatively wipe out nearly all of the costs, even costs associated with operational metrics that the Commission has approved in past cases, including *Peoples 2007*.

The Utilities recognize that the Proposed Order's recommendations are based on "standards" adopted by the Commission in a number of past rate cases, but the evidentiary record shows that the application of those standards here is unsound. The evidence is uncontradicted that the total compensation (including base pay plus incentive pay and other compensation and benefits) paid by the Utilities is prudent and reasonable. Disallowing prudent and reasonable compensation costs is not appropriate based on the evidence or the law. *See, e.g., Village of Milford v. Illinois Commerce Comm'n*, 20 Ill. 2d 556, 565 (1960) ("*Milford*") (affirming recovery of reasonable salaries). Moreover, the evidence shows that the metrics of the incentive compensation programs benefit customers as well as the Utilities. The Proposed Order in substance adopts the view that only certain types of benefits "count", but that is arbitrary.

The Commission's past standards for recovery of incentive compensation costs should not be applied when the evidence shows that they cannot be reconciled with the facts, including the only expert evidence on the subject of human resources management and the realities of the labor markets in which the Utilities operate.

[15] The above figures are derived from Peoples Gas' final revised Schedules C-1 (NS-PGL Ex. SM-3.1P) and B-1 (NS-PGL Ex. JH-3.1P) and the utility's final revised proposed overall ROR of 9.11% and ROE of 11.87% (NS-PGL Ex. BAJ-3.1P).

Rider ICR. The Proposed Order fairly examines the evidence submitted and legal arguments made in support of and in opposition to Rider ICR and reaches the proper conclusions that the record evidence meets the standard set forth by the Commission for the approval of such an infrastructure initiative, that no legal barriers exist to the approval of Rider ICR, and that, with Staff's proposed changes to the rider mechanism accepted by Peoples Gas, Rider ICR as proposed by Peoples Gas should be approved. Furthermore, the Proposed Order correctly found that Staff's proposals to require an accelerated program under 220 ILCS 5/8-503, to submit an implementation plan for approval in a separate Docket with analysis by an outside consultant retained by the Commission and paid for by Peoples Gas, and to require periodic updates with analysis by an outside consultant retained by the Commission and paid for by Peoples Gas were not supported by the record evidence and, therefore, should not be accepted. As substantiated by the weight of evidence in the record, Rider ICR will help enable the acceleration of Peoples Gas' main replacement program, which will provide benefits to customers, workers, and the City in terms of improved safety, cost savings, reduced environmental impacts, increased and/or new functionalities, and job creation. Accordingly, the Proposed Order rightly concludes that the record in this proceeding presents an extraordinary and unique circumstance for the Commission to properly and pragmatically exercise its legal authority to approve Rider ICR.

Cost of Service, Rate Design, and Tariffs. The Proposed Order generally resolves the contested cost of service, rate design, and tariff issues in accordance with the evidence. However, the adoption of "demand rates" for Service Classification No. 1, Small Residential Service, is flawed, particularly in its reliance on an incorrect conclusion about how the Utilities propose to recover demand costs.

The Utilities, subsequent to the conclusion of briefing, reached what they believe is an acceptable resolution of the only contested issue concerning their large volume transportation programs and present that resolution in this brief. Finally, while the Utilities disagree that mandating workshops to address issues concerning the small volume transportation program is warranted, they do not except to that mandate and propose only changes intended to clarify and better define the scope of the workshops.

ARGUMENT IN SUPPORT OF EXCEPTIONS

Please note that, for ease of reference, the Utilities are using the section numbering of the Proposed Order and are only incorporating those sections as to which they propose Exceptions.

III. REVENUE REQUIREMENT

A. North Shore

EXCEPTION NO. 1

The Proposed Order approves a revenue requirement for North Shore of $78,554,000, yielding a revenue deficiency (rate increase) of $13,254,000 (reflecting net operating income of $14,687,000). ALJPO at 7, 277, and App. B at 1.

For the reasons appearing of record and discussed in the Utilities' Initial and Post-Hearing Reply Briefs and in support of Exception Nos. 3 and 6 through 16 below, the Commission should approve a North Shore revenue requirement of $83,305,000 and rate increase of $18,105,000 (reflecting net operating income of $16,301,000). NS-PGL

Ex. SM-3.1N.[16] Therefore, the Commission should adopt Exception No. 1 as set forth in the NS-PGL Exceptions.[17]

B. <u>Peoples Gas</u>

EXCEPTION NO. 2

The Proposed Order approves a revenue requirement for Peoples Gas of $527,108,000, yielding a revenue deficiency of $66,248,000 (reflecting net operating income of $94,667,000). ALJPO at 7, 277, and App. A at 1.

For the reasons appearing of record and discussed in the Utilities' Initial and Post-Hearing Reply Briefs and in support of Exception Nos. 4 through 16 below, the Commission should approve a Peoples Gas revenue requirement of $574,038,000 and rate increase of $113,178,000 (reflecting net operating income of $118,498,000). NS-PGL Ex. SM-3.1P.[18] Therefore, the Commission should adopt Exception No. 2 as set forth in the NS-PGL Exceptions.

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[16] Please note: If North Shore's and Peoples Gas' positions are approved in whole, then North Shore's surrebuttal figures, set forth above, and Peoples Gas' surrebuttal figures, set forth below, would need to be modified in certain respects. First, the figures assumed the Utilities' compromise proposal of adopting Staff's proposed injuries and damages operating expenses adjustment and making the corresponding changes to the injuries and damages reserve in rate base, but Staff rejected and the Proposed Order did not adopt that compromise. ALJPO at 84-86. Second, the figures did not reflect the final, uncontested amounts for Staff's merger cost and savings adjustments. NS-PGL Initial Brief ("Init. Br.") at 52 and fn. 66. Finally, in an effort to narrow the issues, the Utilities are not presenting Exceptions on the subjects of the Proposed Order's recommendations on three subjects: non-union base wages, advertising expenses, and costs of long-term debt.

[17] Please note: The NS-PGL Exceptions address revised language of the narrative portion of the Proposed Order. North Shore's and Peoples Gas' proposed revisions to the rate base and operating income Schedules in Appendices A and B of the Proposed Order in effect are set forth in the rate base and operating income Schedules attached to the respective surrebuttal testimony of Utilities' witnesses Ms. Moy and Mr. Hengtgen (NS-PGL Ex. SM-3.1N, SM-3.1P, JH-3.1N, JH-3.1P), because the latter Schedules reflect the results of adoption of the Utilities' Exceptions, subject only to the modifications referenced in fn. 16, *supra*.

[18] Please note: If Peoples Gas' positions are approved in whole, then its surrebuttal figures, set forth above, would need to be modified in certain respects, as discussed in fn. 16, *supra*.

IV. RATE BASE

A. Overview

1. North Shore

EXCEPTION NO. 3

The Proposed Order approves a rate base for North Shore of $182,869,000. ALJPO at 38, 276, and App. B at 5.

For the reasons appearing of record and discussed in the Utilities' Initial and Post-Hearing Reply Briefs and in support of Exception Nos. 6 through 8 below, the Commission should approve a North Shore rate base of $179,927,000, assuming that the Commission finds that the Peoples Gas pension asset and the North Shore pension liability should be included in rate base, or $187,871,000 if the Commission finds that both should be excluded from rate base. NS-PGL Ex. JH-2.7N.[19] Therefore, the Commission should adopt Exception No. 3 as set forth in the NS-PGL Exceptions.

2. Peoples Gas

EXCEPTION NO. 4

The Proposed Order approves a rate base for Peoples Gas of $1,201,354,000. ALJPO at 38, 276, and App. A at 5.

For the reasons appearing of record and discussed in the Utilities' Initial and Post-Hearing Reply Briefs and in support of Exception Nos. 5 through 8 below, the Commission

[19] Please note: If North Shore's positions are approved in whole, then its rate base figure needs to be corrected to remove the compromise proposal relating to injuries and damages. *See* fn. 16, *supra*.

should approve a Peoples Gas rate base of $1,300,750,000. NS-PGL Ex. JH-3.1P.[20] Therefore, the Commission should adopt Exception No. 4 as set forth in the NS-PGL Exceptions.

C. **Plant**

2. **Gathering System Phase 2 Project (PGL)**

EXCEPTION NO. 5

The Proposed Order, while approving the Utilities' forecasted plant additions in general (ALJPO at 14), recommends that the 2010 investment amount associated with the "Gathering System Phase II" project be removed from the forecasted additions, and reduces Peoples Gas' rate base by a net $2,756,000 ($2,850,000 of Gross Utility Plant less $71,000 of depreciation reserve and $23,000 of Accumulated Deferred Income Taxes ("ADIT")) and its depreciation expense by $71,000 on the basis of that adjustment. ALJPO at 18 and App. A at 3, 6. The Commission should not adopt that recommendation because Peoples Gas removed the Gathering System Phase II project from its forecasted additions in its rebuttal testimony. Alternatively, the calculation of the adjustment should be corrected, because the rate base reduction should be increased to $2,850,000 and there should be no reduction in depreciation expense.

Phase II of the project involves replacement of pipe in the gathering system. Puracchio Reb., NS-PGL Ex. TLP-2.0 at 4:85 - 5:93. Phase II really is a series of projects that replace sections of pipe over time. *E.g.*, Puracchio Sur., NS-PGL Ex. TLP-3.0 at 4:72-83.

Based on further review, Peoples Gas has recognized that it already removed the 2010 Gathering System Phase II project amount from its forecasted plant additions in rate base in its rebuttal testimony, recognizing that the plant associated with that amount would not be in service

[20] Please note: If Peoples Gas' positions are approved in whole, then its rate base figure needs to be corrected to remove the compromise proposal relating to injuries and damages. *See* fn. 16, *supra*.

until 2011. *See* NS-PGL Ex. JH-2.3P at page 2 (removal of $10,800,000 for Gathering System Project).[21] Thus, even assuming that the Proposed Order's reasoning on the merits of whether the 2010 amount for this project should be included in the forecasted additions were to be correct, the Proposed Order's adjustment duplicates the removal of this project from the forecasted plant additions that Peoples Gas made in rebuttal and so it should not be adopted. Therefore, the Commission should adopt Exception No. 5 as set forth in the NS-PGL Exceptions.

Peoples Gas notes that its final revised Construction Work in Progress ("CWIP") amount in rate base does include a forecasted 2010 average figure that incorporates $2,850,000 associated with the 2010 costs of the Gathering System Phase II project. NS-PGL Ex. JH-2.3P at page 3 ($5,700,000 amount ultimately reduced by half due to the averaging used to calculate rate base). However, the Proposed Order's reasoning on the merits of whether the 2010 amount for this project should be included in the forecasted additions does not support any adjustment to the CWIP amount. CWIP in rate base is intended to allow a utility to include a reasonable amount for the costs of ongoing construction activities that have not been completed and put into service, the costs of which are recorded as CWIP not accruing Allowance for Funds Used During Construction ("AFUDC"), not to recover the individual projects that at any given time are part of the CWIP balance(s) used to calculate the amount of CWIP in rate base. *See, e.g.*, Hengtgen Dir., PGL Ex. JH-1.0 at 9:202 - 10:207.

Also, the evidence supporting the 2010 costs warrants their inclusion in the CWIP in rate base. Puracchio Reb., NS-PGL Ex. TLP-2.0 at 6:120 - 7:141; Puracchio Sur., NS-PGL

[21] The impact on rate base of removing the $10,800,000 was a lower figure, because first the reduction was slightly offset by the associated depreciation reserve and ADIT impacts, and then the net result was reduced by 50% due to the averaging used to calculate rate base. The impact on operating expenses was to reduce depreciation expense by removing the depreciation expenses associated with the project, *i.e.*, by removing the same amount as the amount by which the depreciation reserve was reduced in the final averaged calculation of rate base.

Ex. TLP-3.0 at 4:75 - 5:93; NS-PGL Cross Exs. Effron 28, 29. Contrary to the Proposed Order's statements (at 18), that evidence strongly supports the prudence and amount of the 2010 costs (any uncertainty is limited to some of the pipe replacement in later years of the project). The Proposed Order (at 18) notes that approval for those costs has not yet been obtained from the Board of Directors, but this is a future test year case, the Proposed Order recognizes that the fact that Board approval has not yet been obtained is not controlling (*id*.), and, in any event, the uncontradicted evidence is that Board approval is expected in late 2009 or early 2010. NS-PGL Cross Ex. Effron 29 at 2; *see also* Puracchio Sur., NS-PGL Ex. TLP-3.0 at 4:75-77. Therefore, again, the Commission should adopt Exception No. 5 as set forth in the NS-PGL Exceptions.

Finally, in the alternative, the Proposed Order's calculation of the adjustment should be corrected in two respects. First, the Proposed Order's adjustment to rate base should be increased by $94,000, because the amount in CWIP for the project is $2,850,000, not $2,850,000 less $71,000 of depreciation reserve and $23,000 of ADIT. Second, there should be no reduction in depreciation expense because once the project was removed from rate base no amount of depreciation was included for the project in operating expenses.

H. <u>OPEB Liabilities and Adjustment to Remove Pension Asset</u>

<u>EXCEPTION NO. 6</u>

The Proposed Order (at 36-37 and App. A at 6) errs in excluding Peoples Gas' pension asset from rate base, which decreases rate base by $95,765,000, although the Proposed Order is correct that, if the Peoples Gas pension asset should be excluded then so should the North Shore pension liability. Peoples Gas has demonstrated that the pension asset has been created with investor-supplied funds and, therefore, it is entitled to earn a rate of return on the asset. However, even if the Commission determines that the Proposed Order's recommendations here should stand, a mathematical correction should be made to the Proposed Order as it inadvertently omits an adjustment to ADIT relating to North Shore's pension liability.

1. Peoples Gas' Pension Asset Should Be Included in Rate Base As It Was Created by Investor-Supplied Funds

The Proposed Order errs in concluding that Peoples Gas' pension asset was created with customer-supplied funds and as such should be excluded from rate base (ALJPO at 36-37). The evidence demonstrates that Peoples Gas' pension asset was created in two ways, through pension fund contributions and negative pension expense.

First, pension fund contributions are based on management decisions with various legal considerations contained in the Employee Retirement Income Security Act of 1974 ("ERISA") and the Internal Revenue Code ("IRC").[22] Felsenthal Reb., NS-PGL Ex. AF-1.0 at 6:114-121. However, pension expense, which is reflected in rates and calculated in accordance with Financial Accounting Statement ("FAS") 87, represents the annual pension cost that is actuarially determined in a manner that changes each period with the net cost of such benefits attributable during that annual period. *Id.* at 6:129-130. The funding rules set forth under ERISA and the IRC are different than the methodology used to determine pension expense under FAS 87. *Id.* With the adoption of FAS 87, the trigger between pension expensing and pension funding was eliminated. *Id.* at 19:416-417. Therefore, pension contributions are made with investor-supplied funds. Moreover, legally, utility customers pay for service, not for the property used to render it. *Board of Public Utility Commissioners, et al. v. New York Tel. Co.*, 271 U.S. 23 (1926).

[22] The constraints regarding pension funding include: required minimum and maximum contribution levels deductible for income tax purposes and the utility's responsibility to protect the interests of the plan participants and beneficiaries. Felsenthal Reb., NS-PGL Ex. AF-1.0 at 6:114-121.

Second, a pension asset also is created when the annual pension cost computed under FAS 87 is a negative expense – meaning that the expected return on plan assets exceeds other components of pension cost. Felsenthal Reb., NS-PGL Ex. AF-1.0 at 9:177-183. For the period 1996 through 2003, there is a total negative pension expense of $174.3 million.

Year(s)	**Pension Expense (in Millions)**
1996	$(9.0)
1997	$(26.8)
1998	$(28.2)
1999	$(21.9)
2000	$(37.3)
2001	$(21.9)
2002	$(25.0)
2003	$(4.2)
Total 1996-2003	$(174.3)

Felsenthal Sur., NS-PGL Ex. AF-2.0 at 5:94-96. For the period 2004 through 2009, which is what Staff focused upon, there is a net pension expense of only $18,394,032. Pearce Reb., Staff Ex. 16.0 at 8:189 - 9:225; Staff Init. Br. at 34. Neither the Proposed Order nor Staff have addressed this evidence of negative pension expense – only citing prior Commission Orders to support the exclusion of the pension asset. Furthermore, an additional reason for negative expense, particularly relevant to Peoples Gas, is the result of pension plan participants accepting lump-sum distributions in lieu of a stream of pension plan benefits, thereby eliminating pension plan obligations and triggering the recognition of a portion of unrealized gains. Felsenthal Reb., NS-PGL Ex. AF-1.0 at 9:189-194. The Proposed Order's conclusion ignores that fact.

Peoples Gas has demonstrated that the prepaid pension asset is the cumulative difference between what has been contributed to the pension plan by Peoples Gas, using investor-supplied funds, and what has been expensed under FAS 87. Felsenthal Reb., NS-PGL Ex. AF-1.0 at 10:202-203. Because the ratemaking process is based on pension expense, the prepaid pension asset also represents amounts that have been contributed by Peoples Gas to the pension fund that have not been recovered, or that have been treated as a negative pension expense. *Id.* at 10:204-207 (emphasis added).

The Proposed Order also errs in concluding that the recent decision by the Illinois Appellate Court[23] affirming the Commission's decision in the 2005 ComEd rate case supports exclusion of the pension asset. In its Order on Rehearing in ICC Docket No. 05-0597, the Commission excluded the ComEd pension asset from rate base but allowed ComEd to recover at ComEd's cost of long-term debt an $803 million contribution to the pension plan that was made using funds supplied by ComEd's ultimate parent company.[24] The Appellate Court reasoned that ComEd had failed to carry its burden of proving that recovery of the $803 million contribution at ComEd's full cost of capital was reasonable or that there was not a less expensive alternative to funding the contribution than that full cost of capital. *ComEd 2005 Appeal* at 16-17. Therefore, the question on appeal did not revolve around whether the funds used to contribute to the pension plan were investor-supplied, but around whether financing the contribution at the utility's full cost of capital, rather than its cost of long-term debt, was proven to be reasonable.

Furthermore, the only significant difference between the facts in the 2005 ComEd rate case and the instant proceedings is that the source of the pension asset is not fully as direct here, in that it reflects both pension contributions (there funded directly by the ultimate parent company) and negative pension expense. Felsenthal Reb., NS-PGL Ex. AF-1.0 at 27:575-576. As Mr. Felsenthal testified:

[23] *Commonwealth Edison Co. v. Illinois Commerce Comm'n, et al.*, Nos. 2-06-0184 Cons., 2009 WL 3048420 (Ill. App. Ct. 2d Dist. Sept. 17, 2009) (*ComEd 2005 Appeal*).

[24] *In re Commonwealth Edison Company*, ICC Docket No. 05-0597 (Order on Rehearing Dec. 20, 2006) at 28-29.

> [T]the source of Peoples Gas' pension asset is a combination of debt and equity investors – either through direct contributions (similar to Commonwealth Edison Company) or through negative pension expense, a non-cash credit reducing cash flows producing a requirement to obtain investor funds to "pay" for other cash expenses. But, in either case, the source of the prepaid pension asset is the investor, not the ratepayer, requiring a return on such investment.

Id. at 27:578-584.[25]

Thus, neither the Commission's decision in the 2005 ComEd rate case nor *ComEd 2005 Appeal* supports denying Peoples Gas a rate of return on its pension asset. *ComEd 2005 Appeal* decided a factual matter about which rate of return should be allowed on the pension contribution, and does not stand for the proposition that no return on the pension asset should be allowed. Here the record supports inclusion of the pension asset in rate base, as discussed in the Utilities' Initial Brief (at 40-45) and Reply Brief (at 17-23) and herein.

Furthermore, the Proposed Order ignores that customers have benefitted in two ways from negative pension expense: (1) reduced operating expenses to the extent reflected in rates; and (2), all else being equal, the need for additional rate cases is reduced. Felsenthal Reb., NS-PGL Ex. AF-1.0 at 14:296-297, 15:316-328.

Moreover, because Peoples Gas has not been allowed by the Commission to include its pension asset in rate base, investors are not allowed to earn a return on their investment (*id.* at 20:425-426), and that serves as an incentive for Peoples Gas to make only the minimum required pension plan contributions, resulting in greater risk to employees as to the availability of sufficient pension plan funds to pay ultimate plan benefits. *Id.* at 20:426-428. The Proposed Order pays no heed to Peoples Gas' point that the Commission, in the interests of employees and customers as well as utilities, should encourage adequate pension plan funding, not send signals

[25] The Order in *Peoples 2007* recognized that Peoples Gas and North Shore recently had made pension contributions of $15,278,614 and $1,862,247, respectively. *Peoples 2007* at 36.

to do less. In its 2005 ComEd rate case Order on Rehearing, the Commission acknowledged that "the [pension] contribution assisted in providing adequate funding for the retirement obligations to ComEd's workforce and … ComEd's customers saved $30.2 million as a result of the contribution." *In re Commonwealth Edison Co.*, ICC Docket No. 05-0597 (Order on Rehearing Dec. 20, 2006), at 28.

Finally, denying a return on the pension asset also is contrary to Illinois law, which requires the Commission to establish rates that give the utility the opportunity to earn its authorized return. *E.g., 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 (3d Dist. 1987).

If the Commission determines that the pension asset should be included in Peoples Gas' rate base, then it is also appropriate to include the North Shore's pension liability in its rate base. In fact, because Peoples Gas' pension asset, North Shore's pension liability, and the Utilities' "OPEB" (other post-employment benefits) liabilities each represent a commitment to pay retirees, either a pension or a promised health and welfare benefit, there is no reason to treat them differently. Felsenthal Reb., NS-PGL Ex. AF-1.0 at 23:489-495.

Thus, for all the reasons stated herein and in the Utilities' Initial Brief (at 40-45) and Reply Brief (at 17-23), and in the underlying evidence in the record, Peoples Gas' pension asset and North Shore's pension liability, along with both Utilities' OPEB liabilities, should be included in rate base. Accordingly, the Proposed Order should be revised as shown in Exception No. 6 in the NS-PGL Exceptions.

2. <u>Alternative Necessary Corrections to the Proposed Order</u>

If the Commission determines that the Proposed Order correctly concludes that Peoples Gas' pension asset and North Shore's pension liability should be excluded from rate base, then a correction is needed to the calculation of North Shore's rate base. On line 16, column (g) of page 5 of Appendix B of the Proposed Order, the correct amount of North Shore's pension liability is reflected, but in line 13, column (g), on page 5, the amount of ADIT related to the pension liability, $218,000 (*see* NS-PGL Ex. JH-2.7N at line 24, column (I)), mistakenly is omitted. Therefore, North Shore respectfully requests that $218,000 be added to line 13, column (g), of page 5 of Appendix B of the Proposed Order.

This correction would not affect pages 36-37 of the Proposed Order. However, the correction does affect the North Shore rate base figures on pages 8, 38, and 317 of the Proposed Order. Also, as a result, it affects the correct determinations of the utility's operating income requirement and therefore its revenue requirement and its revenue deficiency in various locations in Appendix B and the Proposed Order.

I. <u>Approved Rate Base</u>

<u>EXCEPTION NO. 7</u>

Exception No. 7 revises the summary rate base table on page 38 of the Proposed Order in accordance with Exceptions Nos. 3 through 6.

V. <u>OPERATING EXPENSES</u>

C. <u>Contested Issues</u>

1. <u>Incentive Compensation</u> (Falls in Multiple Categories of O&M)

<u>EXCEPTION NO. 8</u>

(a) <u>The Proposed Order's Recommendations</u>

Because of the complexity of this subject, the discussion here begins with setting forth the details of the disallowances of incentive compensation costs that are recommended by the Proposed Order.

Totals. The Proposed Order (at 59-60 and App. A at 2, 6, 10-14, and App. B at 2, 5, 8-12) recommends disallowing the following incentive compensation program costs:

	Operating Expenses (Before Income Taxes) ("OE")	Rate Base ("RB")*
PGL	$8,422,000	$547,000
NS	$1,850,000	$106,000

Sources: ALJPO at App. A at 2, line 19, col. (c), and at 6, line 23, col. (b); ALJPO at App. B at 2, line 19, col. (c), and at 5, line 23, col. (b).
*All rate base numbers in this discussion are net numbers, meaning they are Gross Plant minus associated Depreciation Reserve and associated ADIT.

Peoples Gas Amounts Breakdown. The Proposed Order's recommendations involve four "buckets" of disallowed costs plus certain derivative impacts. As to the first two buckets, the Proposed Order recommends partial disallowances on three of the four grounds urged by Staff (which still amounts to disallowing nearly all of the costs), while as to the other two buckets it recommends complete disallowance as does Staff.

	OE Disallowances	RB Disallowances
Non-executive Plan Costs	$4,003,000 out of $4,280,000; plus $12,000 of depreciation expense for RB disallowances	$483,000 out of $517,000
Executive Plan Costs	$694,000 out of $816,000	N/A
Stock Plans Costs	$3,067,000 out of $3,067,000	N/A
Capitalized Costs Disallowed in 2007 Rate Cases	$2,000 of associated depreciation expense	$166,000
[Derivative payroll taxes / accumulated depreciation and ADIT impacts]	$644,000	($99,000) (accum. deprec.) ($3,000) (ADIT)
Totals	$8,422,000	$547,000

Source: ALJPO at App. A at 10 -14.

North Shore Amounts Breakdown. The Proposed Order's recommendations here also involve four "buckets" of disallowed costs plus certain derivative impacts. Also, again, as to the first two buckets, the Proposed Order recommends partial (nearly complete) disallowances on three of the four grounds urged by Staff, while as to the other two buckets it recommends complete disallowance as does Staff.

	OE Disallowances	RB Disallowances
Non-executive Plan Costs	$962,000 out of $1,071,000; plus $2,000 of depreciation expense for RB disallowances	$95,000 out of $105,0000
Executive Plan Costs	$137,000 out of $161,000	N/A
Stock Plans Costs	$609,000 out of $609,000	N/A
Capitalized Costs Disallowed In 2007 Rate Cases	$0	$27,000
[Derivative payroll taxes / accumulated depreciation and ADIT impacts]	$140,000	($15,000) (accum. deprec.) ($1,000) (ADIT)
Totals	$1,850,000	$106,000

Source: ALJPO at App. B at 8 - 12.

(b) The Utilities' Incentive Compensation <u>Costs Should Be Approved</u>

The prudence and reasonableness of the incentive compensation costs at issue are proven and undisputed. The Proposed Order does not and could not find otherwise. The evidence of customer benefits also is proven and, apart from the Proposed Order's adoption of Staff's use of the Commission's "standards" for incentive compensation cost recovery from past rates cases to in effect determine that certain benefits do not "count", the evidence of customer benefits also is undisputed. The Commission must decide this case based on the evidence in the record. 220 ILCS 5/10-103, 10-201(e)(iv(A). The disallowance of the costs at issue is unwarranted given the evidence and contrary to law.

<u>**Prudent and Reasonable and Customer Benefits**</u>. No witness challenged the testimony of the Utilities' witness, James Hoover, the Director of Compensation of the Utilities' ultimate

parent company, with over 25 years of experience in human resources, regarding the prudence and reasonableness of each of the incentive compensation plans at issue.[26] Mr. Hoover's uncontradicted testimony established, among other things, that: (1) the Utilities design their total cash compensation packages (base pay plus target incentive pay) at market median based on other energy service companies based on data from Towers Perrin, a nationally recognized compensation and benefits firm; and (2) the Utilities design their total compensation programs, including their incentive compensation programs, in order to attract and retain a sufficient, qualified, and motivated work force. *E.g.*, Hoover Reb., NS-PGL Ex. JCH-1.0, 6:128 - 8:164.

Even in today's economic environment, the Utilities' approach is prudent and reasonable, and the alternative of moving more compensation to base pay would put them at a disadvantage in the labor market. Hoover Reb., NS-PGL Ex. JCH-1.0 at 7:141-151.

Mr. Hoover also testified that attracting and retaining such a work force benefits customers by making sure there are enough employees to perform needed work, maintaining and improving the quality of work, and reducing the costs of recruiting and retaining new employees. *E.g.,* Hoover Reb., NS-PGL Ex. JCH-1.0, 8:159-164. That evidence also is uncontradicted, apart from Staff's and the AG's contentions that those benefits should not "count".

With regard to customer benefits, Mr. Hoover's testimony also established, among other things, that:

- The "financial" metrics of the plans are net income metrics, which have both a cost side and a revenue side. Even though the Commission has not approved net

[26] Neither the Staff witness nor the AG-CUB witness is an expert on human resources. *See* Hathhorn Dir., Staff Ex. 1.0 at 1:17 – 2:25; Hathhorn, Tr. at 712:13 - 713:1; Effron Dir., AG-CUB-City Ex. 1.0 at 1:6 – 2:44.

income metrics in prior cases, it has approved cost control metrics as benefitting customers.[27] So, logically, the costs tied to net income metrics should be allowed.

- The operational measures "behind" the financial measures in the non-executive plan have direct benefits to customers, such as reducing system leaks and improved operational safety (and that the Commission previously has approved).
- The targets are set each year to motivate employee behavior and are considered achievable stretch goals designed to motivate employee achievement from a competitive level to an outstanding level.
- The metrics involving achievements by affiliates benefit Illinois customers, because it encourages the sharing of best practices.

Hoover Reb., NS-PGL Ex. JCH-1.0 at 3:56 - 8:176; Hoover Sur., NS-PGL Ex. JCH-2.0 at 2:27 - 4:72.

Mr. Hoover also testified, as to the stock plans, that they are an important part of the overall total compensation package, again are designed to help attract and retain a qualified and motivated work force, and that without them the Utilities' compensation packages would be less competitive because their labor market competitors, both energy and non-energy companies, offer compensation packages that include base pay, incentive pay, and stock plans. Hoover Reb., NS-PGL Ex. JCH-1.0 at 9:178-188; Hoover Sur., NS-PGL Ex. JCH-2.0 at 4:73-79.[28]

[27] The Commission repeatedly has found that incentive compensation plans that reward employees for controlling costs benefit customers. *See, e.g., In re Commonwealth Edison Co.*, ICC Docket No. 01-0423, at 129 (Order March 28, 2003); *In re Consumers Illinois Water Co.*, ICC Docket No. 03-0403, at 14-15 (Order April 13, 2004); *In re Northern Illinois Gas Co.*, ICC Docket No. 95-0219, 1996 Ill. PUC Lexis 204, *62 (Order April 3, 1996).

[28] As to the fourth costs "bucket", Mr. Hengtgen made the point that the capitalized amounts disallowed under the Order in the 2007 rate cases are on appeal. Hengtgen Reb., NS-PGL Ex. JH-2.0 at 16:341-350.

Legal Standards. The Proposed Order erroneously disregards the uncontradicted evidence regarding the prudence and reasonableness of the incentive compensation costs and the benefits received by customers. The Commission, however, must apply Illinois law governing uncontradicted evidence. "Where the testimony of a witness is neither contradicted, either by positive testimony or by circumstances, nor inherently improbable, and the witness has not been impeached, that testimony cannot be disregarded by the trier of fact." *Bazydlo v. Volant*, 164 Ill. 2d 207, 215 (1995).[29]

The principle that a utility should recover its prudent and reasonable costs of service is well-established. For example, in *CUB*, the Supreme Court of Illinois stated that:

> A public utility is entitled to recover in its rates certain operating costs. *(Citizens Utilities Co. v. Illinois Commerce Comm'n (1988), 124 Ill. 2d 195, 200-01, 124 Ill.Dec. 529, 529 N.E.2d 510*.) In setting rates, the Commission must determine that the rates accurately reflect the cost of service delivery and must allow the utility to recover costs prudently and reasonably incurred. (220 ILCS 5/1-102(a)(iv) (West 1992).)

CUB, 166 Ill. 2d at 121.

It is settled law, moreover, that employee salaries are operating expenses and, as such, are recoverable in full so long as they are prudent and reasonable. *See, e.g., Village of Milford v. Illinois Commerce Comm'n*, 20 Ill. 2d 556, 565 (1960) (*Milford*).

Moreover, arbitrary and unreasonable disallowances are unlawful. *E.g., Illinois Power Co. v. Illinois Commerce Comm'n*, 339 Ill. App. 3d 425, 431 (5th Dist. 2003); *see also Commonwealth Edison Co. v. Illinois Commerce Comm'n*, 180 Ill. App. 3d 899, 906-910 (1st Dist. 1988).

[29] *See also ComEd*, 322 Ill. App. 3d at 849; *Thigpen v. Retirement Bd. of Fireman's Annuity and Benefit Fund of Chicago*, 317 Ill. App. 3d 1010, 1021 (1st Dist. 2000); *Trahraeg Holding Corp. v. Property Tax Appeal Bd.*, 204 Ill. App. 3d 41, 44 (2d Dist. 1990).

The cross-examination of Staff's witness showed, moreover, that its application of the Commission's past standards is illogical and unreasonable. Even when the total compensation paid to employees is prudent and reasonable, Staff's application of the Commission's past decisions would result in arbitrary and illogical selective disallowances depending on the metrics of the incentive portions of the compensation. Hathhorn, Tr. at 719:22 – 727:14. That also makes no sense because Staff's witness admitted that the fact that a metric benefits shareholders does not necessarily mean that it is contrary to the interests of customers, and that if a metric benefits both shareholders and customers that does not mean shareholders should bear all of the costs associated with the metric. Hathhorn, Tr. at 714:16 – 715:17.

The Proposed Order (at 59) relies in part on the affirmance of the Commission's Order in the 2005 ComEd rate case by *ComEd 2005 Appeal*. That reliance is unsound.

In the 2005 ComEd rate case, the Commission allowed the utility to recover half of its incentive compensation costs. *In re Commonwealth Edison Co.*, ICC Docket No. 05-0597 (Order July 26, 2006) at 95-97. ComEd appealed. The Illinois Appellate Court for the Second Judicial District recently affirmed. *ComEd 2005 Appeal* at 9-14.

The Second District noted established law on a utility's recovery of its prudent and reasonable costs, and added to that the proposition that the costs must pertain to the utility's tariffed services, citing *DuPage Util. Co. v. Illinois Commerce Comm'n*, 47 Ill. 2d 550, 560 (1971) ("*DuPage*"), which distinguished *Milford.* *ComEd 2005 Appeal* at 10-11. That proposition and the citation of *DuPage* do not support the Proposed Order here.

In *DuPage,* the Court, in affirming the disallowance of half of the salaries of three company officers of a utility with 840 customers, distinguished *Milford*, but in *DuPage* the Commission found and the evidence supported that the salaries were excessive rather than reasonable, including evidence that the officers only worked part-time and maintained only a minimal contact with the utility's day to day operations, and that their salaries were disproportionately high compared to comparable utilities. *DuPage*, 47 Ill. 2d at 560. There is no claim, much less any evidence, of excessive compensation on those or any other grounds in the instant cases. The only evidence is to the contrary. The Second District also discussed some of ComEd's evidence of customer benefits, finding that "this evidence certainly does provide support for ComEd's position, it does not compel the conclusion that ComEd seeks." *ComEd 2005 Appeal* at 13. Finally, and critically, the Second District relied on the fact that the Commission had approved half of ComEd's incentive compensation costs.

> If we were deciding this issue in a vacuum, we might agree with ComEd. However, in this case, three other performance-based components of the incentive plan existed. Thus, the Commission could have reasonably concluded that the earnings-per-share portion of the plan provided only a tangential benefit to ratepayers. Indeed, the Commission characterized this portion of the incentive plan as "generic and broad" in contrast to the other three more specific components. Moreover, precedent exists for apportioning employee compensation costs between equity holders and ratepayers where an employee's duties only partially benefit ratepayers. See *Candlewick Lake Utilities Co.* [*v. Illinois Commerce Comm'n*], 122 Ill. App. 3d [219] at 226 [(2d Dist. 1983) ("*Candlewick*")]. Meischeid's testimony that such plans benefit everyone necessarily entails the proposition that they provide only some benefit to customers and thus provides an adequate basis for the Commission's decision to apportion these costs. Moreover, the notion that an earnings-per-share-based employee incentive plan provides benefits to shareholders is hardly a controversial proposition.

ComEd 2005 Appeal at 14.[30]

In their 2007 rate cases, the Commission approved the Utilities' incentive compensation costs associated with two of their five plans. *Peoples 2007* at 66-67. The allowed costs were

[30] In *Candlewick*, which involved the salary of one company officer, "the Commission noted that it based its decision on the unusual circumstances of an absent non-resident president, the past financial difficulties of the utility including a bankruptcy reorganization, the presence of various management and clerical employees to run the day-to-day operations of the utility, and the fact that the president's duties are undocumented." *Candlewick*, 122 Ill. App. 3d at 226. Again, the instant cases do not involve any claim, much less evidence, of any such circumstances.

(1) the costs associated with the 45% of the non-officers "TIA" plan metrics that were "operational" and (2) all of the costs associated with the individual performance bonus plan. *Id*. The disallowance of the other costs is pending on appeal by the Utilities.

In the instance cases, however, unlike the 2005 ComEd rate case and *Peoples 2007*, the numbers set forth above show that the Proposed Order recommends disallowing almost 100% of the Utilities' incentive compensation costs, even though they include some "operational" metrics, such as metrics tied to system leak reductions and improved operational safety. Thus, the "tangential benefit" and "apportionment" reasoning of the Second District does not apply here. The Utilities respectfully do not share the view that the *DuPage* and *Candlewick* cases support the Commission's standards of past cases, but, even if they did, the *ComEd 2005 Appeal* decision itself still does not support the disallowances recommended by the Proposed Order here, for the reasons set forth above.

Specific Disallowances. The Proposed Order approves three of Staff's four proposed disallowances relating to the non-executive and executive plans. ALJPO at 59-60. Staff argued that its four successive percentage disallowances, which would end up disallowing very close to 100% of the Utilities' non-executive and executive incentive compensation program costs, were warranted on four grounds: (1) the plans include "financial" (net income) metrics that fail the Commission's cost recovery standards, (2) the 2010 targeted levels are unlikely to be achieved, (3) the plans incorporate affiliate performance metrics, and (4) the plans have an Integrys net income trigger (gate). Staff Init. Br. at 50-51, *et seq*. The Proposed Order accepts grounds (1), (3), and (4), but rejects ground (2). ALJPO at 59-60.

As to Staff's first ground, the discussion above shows that, even though the Commission in a number of cases has found that "financial" metrics do not fall within the Commission's standards, and has held or stated that that reasoning applies to net income metrics, the Commission should not apply that reasoning here, based on the facts and the law.

Moreover, even assuming that financial metrics benefit shareholders, that is not a basis for disallowing them. Staff's witness acknowledged that the fact that a metric benefits shareholders does not necessarily mean that it does not also benefit customers (Hathhorn, Tr. 714:16 - 715:17), although she did claim, based on citing past Commission Orders, that net income metrics do not benefit customers.

Furthermore, the financial metrics at issue here, net income metrics, do in fact benefit customers. Staff's witness's testimony on this point apparently proceeds from the premise that net income metrics *a priori* do not benefit customers, because she offers only citations to past Commission Orders, not facts or reasoning, to support that conclusion. Net income metrics indisputably have both a cost side and a revenue side, however, by definition. Hoover Reb., NS-PGL Ex. JH-1.0 at 4:74-75. Even though the Commission has not approved net income metrics in prior cases, it has approved cost control metrics.[31] So, logically, the costs tied to net income metrics should be allowed. Hoover Reb., NS-PGL Ex. JH-1.0 at 4:75-80. In the alternative, they should be disallowed only by half. AG-CUB witness Mr. Effron proposed to disallow only half of the Utilities' incentive compensation costs on the grounds that the metrics are financial (except for his proposal to disallow all costs allocated from affiliates as financial). Effron Dir., AG-CUB-City Ex. 1.0 at 20:426 - 21:462. Even Staff's witness acknowledged that

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[31] The Commission repeatedly has found that incentive compensation plans that reward employees for controlling costs benefit customers. *See, e.g., In re Commonwealth Edison Co.*, ICC Docket No. 01-0423, at 129 (Order March 28, 2003); *In re Consumers Illinois Water Co.*, ICC Docket No. 03-0403, at 14-15 (Order April 13, 2004); *Nicor 1996*, 1996 Ill. PUC Lexis 204, *62.

if a metric benefits both shareholders and customers, that that does not mean that shareholders should bear all of the costs. Hathhorn, Tr. at 714:16 - 715:17.

Staff's third ground is that the metrics include affiliate performance metrics, but the Utilities' witness pointed out that the Utilities and their affiliates share a team-based philosophy that encourages the sharing of best practices that benefit Illinois customers, and that affiliates share in staff support and thus in the support expense. Hoover Reb., NS-PGL Ex. JCH-2.0 at 6:121-125. Staff's brief seems to scoff at the value of sharing best practices (*see* Staff Init. Br. at 58), but, tellingly, it cites no evidence on that point. There is no counter-evidence.

Staff's fourth ground is the plans have an Integrys net income trigger, but the discussion of financial and affiliate-related metrics above applies to that ground.

Finally, the Proposed Order, like Staff's arguments, never addresses the fact that Staff's application of the Commission's "standards" is illogical and unreasonable, as discussed earlier.

Staff's proposed stock plans disallowance depends on similar grounds and suffers from the same flaws as the parallel grounds of its proposed executive and non-executive plan disallowances. *Compare* Staff Init. Br. at 63-64 *with* NS-PGL Init. Br. at 56-57.

Staff's remaining disallowances, which are based on reflecting disallowances in the Utilities' 2007 rate cases, are founded on the Order in *Peoples 2007*, which the Proposed Order (at 60) correctly notes is still in place but on appeal.

The Commission should reject the recommended disallowances. The costs at issue are prudent and reasonable, and they benefit customers in multiple respects. The Commission should adopt Exception No. 8. In the alternative, the Commission should allow one half of the incentive compensation costs at issue, as provided in the alternative within Exception No. 8.

2. Non-union Base Wages (Agreed in Part) (Falls in Multiple Categories of O&M)

The Proposed Order (at 63) adopts, with a modification, Staff's proposed non-union base wages adjustments. Although the Utilities believe that those adjustments should be rejected based on the evidence in the record, they have chosen, in order to narrow the issues, not to file an Exception on this subject. However, should Staff or any intervenor propose an Exception that seeks larger adjustments, then the Utilities reserve the right to advance their original position that no adjustments are warranted.

6. Customer Service and Information

a. Advertising (Agreed in Part)

The Proposed Order concludes that the costs associated with the Utilities' Safety, Reliability and Warmth Campaign ("SRW Campaign") should be disallowed as they are promotional in nature. ALJPO at 82. Although the Utilities believe that the disallowance of the costs associated with the SRW portion is contrary to the evidence, they have chosen, in order to narrow the issues, not to file an Exception on this subject.

F. Total Operating Expenses

EXCEPTION NO. 9

Exception No. 9 revises the summary operating statements table on page 90 of the Proposed Order in accordance with Exceptions Nos. 1 through 8.

VI. RATE OF RETURN

B. Capital Structure

1. North Shore and Peoples Gas Position

EXCEPTION NO. 10

The Utilities request additions to the summary of their position on capital structure as set forth on pages 91 and 92 of the Proposed Order. The first addition supports the Proposed Order's correct conclusion that the Utilities' use of short-term debt distinguishes their circumstances from those presented in the Commission's recent decision on rehearing in *Northern Illinois Gas Company d/b/a Nicor Gas Co.*, ICC Docket No. 08-0363 (Order on Rehearing Oct. 7, 2009). The second addition provides a citation supporting the statement that the Commission has not historically equated capitalization and rate base. The third addition confirms that the Utilities included cash working capital in their rate bases in their last rate cases and the Commission, with Staff support, approved capital structures with no short-term debt component. Hengtgen Dir., PGL Ex. JH-1.0 at 34:740-745; Hengtgen Dir., NS Ex. JH-1.0 at 30:640-645.

C. Cost of Long-Term Debt

2. Peoples Gas

c) Commission Analysis and Conclusion

In order to narrow the issues, the Utilities are not submitting an Exception on this subject.

D. Cost of Common Equity

In general, the Proposed Order provides an excellent treatment of the cost of equity in general and the parties' positions in specific. Although the Utilities take issue with certain of its conclusions, they appreciate the careful analysis that is reflected throughout Section VI.

As discussed below and shown in the Utilities' Exception Nos. 11 through 16, the Utilities continue to maintain that their cost of equity is 11.87% but also offer an alternative, compromise position that their authorized returns on equity should be established at either 10.51% or 10.61% depending on the Commission's decisions. The Utilities' initial position is designated as "Alternative 1". Their compromise position is designated "Alternative 2" and proposes that their cost of equity be established based on (1) Staff's and the Utilities' results using the constant growth form of the DCF model, (2) Staff's and the Utilities' CAPM results, and (3) either Staff's financial risk adjustment or Staff's rider adjustments but not both. As to this last point, "Alternative 2A" refers to the Utilities' compromise proposal that the Commission reject Staff's financial risk adjustment but accept its rider adjustments. Alternative 2A would result in a 10.61% cost of equity for both Utilities. "Alternative 2B" refers to Utilities' alternative proposal that, if the Commission accepts Staff's financial risk adjustment, it should reject Staff's rider adjustments as duplicative and therefore arbitrary. Alternative 2B would result in a 10.61% cost of equity for North Shore and a 10.51% cost of equity for Peoples Gas.

1. Utilities' Position

The Companies' DCF Analysis

EXCEPTION NO. 11

The Utilities request that the summary of their position on Staff's non-constant form of the DCF model at page 100 of the Proposed Order include the Utilities' reasons for disputing Staff's assertion that it is impossible for a firm's growth rate to be higher than overall Gross Domestic Product ("GDP") growth in the long run. This material is necessary for a fair summary of the Utilities' position.

As the Utilities have previously explained, the GDP is comprised of many components, each of which has its own rate of growth. NS-PGL Init. Br. at 91. Logic dictates that one component can grow indefinitely at a rate higher than GDP growth if it is offset by lower growth rates of other components. Contrary to Staff's argument in its Reply Brief (at 35), GDP growth is not a mathematical cap on profit growth (or any other component of GDP growth), but is rather an average growth rate comprised of a range of growth rates some of which are higher than the average and others are lower.

For example, corporate profits, which are a component of the GDP, are forecast to grow at a rate higher than GDP growth from now until 2020. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 17:356-358. This does not mean that an individual corporation or group of corporations will eventually outgrow the entire economy. It means only that there are other growth rates lower than corporate profit growth that are averaged into the GDP growth rate. Corporate profit growth could indeed exceed GDP growth in the long run.

<u>The Companies' CAPM Analysis</u>

<u>EXCEPTION NO. 12</u>

The Utilities request a correction to the discussion on page 101 of the Proposed Order regarding Mr. Moul's criticism of Mr. McNally's risk free rate. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 24:462 -25:480.

4. <u>Commission Analysis and Conclusions</u>

For clarity, the Utilities offer four distinct Exceptions to this section of the Proposed Order. Exception No. 13 would modify the discussion of the Commission's consideration of general financial market conditions, in accordance with Mr. Fetter's testimony. Exception Nos. 14 and 15 present changes that include components of the Utilities' compromise proposal on cost of equity ("Alternative 2"). Exception No. 14 proposes the rejection of Staff's flawed and prejudicial non-constant growth DCF methodology, and instead uses Staff's and the Utilities' constant growth DCF results in conjunction with Staff's and the Utilities' CAPM results. Exception No. 15 proposes either (1) the rejection of Staff's financial risk adjustment and the acceptance of Staff's rider adjustments ("Alternative 2A") or (2) the acceptance of Staff's financial risk adjustment and the rejection of Staff's rider adjustments ("Alternative 2B"). These adjustments, all of which address reductions in the Utilities' cost of equity associated with reduced risk to their recovery of their revenue requirements, are duplicative and therefore arbitrary. Exception No. 16 provides the changes to the "Final Conclusions" and "Weighted Average Cost of Capital" that these alternatives would drive.

EXCEPTION NO. 13

The Proposed Order's discussion of the Commission's use of "contextual" information concerning general conditions in the capital markets should be revised. A general understanding of current market conditions is critical to the regulator's establishment of a utility's authorized return on common equity. In response to a question from Judge Moran, Mr. Fetter described the appropriate approach in today's extraordinary market conditions thus:

> And when an event like [September 11th or Hurricane Katrina] occurs, it doesn't matter what return you've set, whether you've gone up to the expected or whether you've set the minimum required, access to capital is going to dry up during that period, but you want to make sure a few weeks later when the markets are slowly beginning to function again, that Peoples and North Shore are able to access capital that they need and they won't be able to if you've set it . . . at the minimum level of the range, . . . what . . . Mr. Moul described, as the required level as opposed to the expected level. You want to provide the Company with access to capital during mainstream conditions.

Tr. 502:18 – 503:9.

As the economy recovers from a financial crisis worse than any since the Great Depression, it is essential that the Utilities maintain if not enhance their financial strength so that they have ready access to capital at reasonable cost. Tr. 510:5-22. The Utilities' current credit ratings are split between the "A" and "BBB" levels, and a downgrade could drive up their cost of capital up significantly. Tr. 511:1 – 512:17. In order to maintain the Utilities' ready access to capital, the Commission should authorize returns on equity that are among the "mainstream," around 10.50% and moving upward, as opposed to the significantly lower returns proposed by Staff and CUB-City that the capital market is sure to view as well below the norm. Fetter Reb., NS-PGL Ex. SMF-1.0 at 7; Tr. 515:7 – 516:4.

If, as CUB-City advocate, the Commission ignored general financial market conditions and objective information about what investors expect, and instead established authorized returns based on subjective, value-laden judgments about what investors <u>should</u> expect, it would do so at the customers' peril. Customers ultimately pay the Utilities' capital costs and actions that tell the market that the Utilities are less attractive investments than their peers will increase those costs. The Utilities are <u>not</u> advocating that the Commission simply set their returns on equity based on those set for other utilities. Rather, as Mr. Fetter and Mr. Moul testified, the Utilities urge the Commission to consider these conditions when evaluating the reasonableness of the various financial models presented to it, as well as the ROEs that result from the Commission's evaluation.

In order to reflect the conditions that the Utilities actually face in the capital markets, the Proposed Order must be revised. It concludes that Peoples Gas' authorized return should <u>be reduced</u> to 9.93% from its current authorized return of 10.19% set in early 2008 before the credit crisis. The recommendation for North Shore is 10.03%, essentially no change from the 9.99% return set before credit crisis. With respect, returns at these levels defy common sense when we are in the middle of a recession. They are materially below the mainstream and would undermine the Utilities' financial strength as they go to the markets for capital as the markets recover. In fact, according to the Commission's Gas Rate Case Report, these returns would be the lowest authorized for any natural gas utility by this Commission since at least 1972, except for the 9.87% return set for the gas operations of the integrated South Beloit Water, Gas and Electric Company in 2007.

Exception No. 13 offers a description of how the Commission should consider general financial market conditions in its determination of the Utilities' ROEs. Exception No. 16 also includes language for the "Final Conclusions" that reflects consideration of those conditions in light of the ROEs that result from the Commission's evaluation of the various financial model results presented to it.

EXCEPTION NO. 14

The Proposed Order (at 99-100) summarizes well the Utilities' challenge to Staff's recent conversion from the constant growth form of the DCF model to the non-constant form. The ALJs' analysis of this issue, at pages 125-126, appears to reflect a degree of doubt on their part as to the real reasons for that conversion. The ALJs state that they "find reasons" for Staff's switch, but their stark description of those reasons without more is hardly a ringing endorsement. In fact, Staff has not justified its switch, which in this proceeding has been shown to produced a significantly lower return than that produced by the constant growth form of the model on which the Commission has historically relied.

In this case, Staff would have the Commission believe that shortly after the Utilities' last rate cases in 2008, Staff discovered that near-term utility growth rates had become higher than long-term growth projections for the economy overall, so much higher that they justified a changed DCF methodology. In fact, however, near-term utility growth rates in excess of long-term GDP growth is not a new phenomenon. Tr. 528:22 – 530:12. Staff has failed to explain why its use (and this Commission's acceptance) of the constant growth form of the DCF model was reasonable until 2008, and why it was appropriate then to switch to the non-constant growth version.

The constant growth form of the model is widely and appropriately applied to determine the cost of equity of firms, like electric and natural gas utilities, that display relatively steady and moderate growth characteristics. NS-PGL Init. Br. at 89-90. The non-constant growth form of the model is typically applied when a firm exhibits extraordinarily high near-term growth rates that are unlikely to be sustainable in the long run. *Id.*

The more plausible explanation for Staff's conversion to a non-constant growth form of the DCF model is Staff's realization that a non-constant growth form of the model could generate suppressed equity costs if lower growth rates were assumed in the later stages of the model. Staff's switch comes in the wake of declining stock prices, increases in dividend yields and increased growth rates among the Gas Group, all of which contribute to a lower cost of equity with the non-constant growth form of the model. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 20:396 – 23:447. By making that assumption in these cases, Staff reduced its DCF result by more than 150 basis points from 11.76%, which was produced by the constant growth model Staff used in the Utilities' last rate cases, to 10.23% using a non-constant growth form in conjunction with a unique forecast of GDP growth as a proxy for the Utilities' long-term growth rate. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 23 (table).

Apart from being results-driven, Staff's switch is arbitrary because, even if it were true that near-term utility growth rates have been higher than GDP growth only since 2008, it means that Staff used the constant form of the DCF for as long as it generated the lower result and then switched when utility growth rates became higher than GDP growth and the non-constant form began to generate the lower result. The Commission should not countenance such manipulation of the financial models.

Staff's Reply Brief (at 32-34) takes issue with the Utilities' characterization of the Federal Energy Regulatory Commission's ("FERC") application of the constant and non-constant growth forms of the DCF model, but stops short of claiming that FERC would apply the non-constant growth form of the DCF model under the circumstances of these cases. The Utilities maintain that the difference between their forecast growth rates and GDP growth are not large enough to justify the use of the non-constant version, and that if all of the criteria applied by FERC – which also include an analysis of dividend payout ratios and a comparison of utilities relative to other industries – are considered, as Mr. Moul did, the constant growth form of the DCF model is appropriately applied in this case. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 18:361 – 19:381.

For these reasons, the Commission should reject Staff's non-constant DCF model in this case, and should insist that Staff transparently explain its reasons for suddenly departing from the constant growth form of the model in late 2008. In addition to the Utilities' constant growth DCF result, the Commission should also consider the result of Staff's constant growth DCF result, as presented by Mr. Moul and not contested by Staff. Averaging these two results yields a DCF cost of equity of 11.215%.

EXCEPTION NO. 15

Notably, the Proposed Order (at 128) offers no analysis to support the acceptance of Staff's financial risk adjustment in this case. The Utilities have identified two fatal flaws in Staff's approach, either of which should cause the Commission to reconsider its continued adherence to this systematic, arbitrary and punitive reduction of utility authorized returns on equity.

The first fatal flaw is Staff's development of hypothetical credit ratings for the Utilities based on the theoretically unrealistic and historically unsupportable assumption that they will earn 100% of their revenue requirements, and then comparing those fictional and idealized credit ratings to the average <u>actual</u> credit rating of the Gas Group. The theoretical flaw in this "apples to oranges" comparison is plain: the Commission's approval of rates provides the utility with only an <u>opportunity</u> to recover the underlying revenue requirement, including its authorized return on equity; it by no means assures such recovery. This fact is well understood and accepted by Staff. Indeed, the entire underpinning of Staff's proposed cost of equity adjustments for riders is that they reduce the utility's risk of not recovering its authorized revenue requirement. Apart from theory, history has proven time and again – most recently with the Utilities' experience since their authorized returns were set <u>with similar Staff adjustments</u> less than two years ago – that the utility's opportunity to earn an authorized return is a much different thing than actually earning it.

Yet, despite the theory and history to the contrary, Staff's financial risk adjustment relies on the assumption that Utilities will recover their authorized revenue requirement in full. Staff's methodology understates the Utilities' actual financial risk, overstates their actual credit ratings, and generates a downward adjustment in their cost of equity based on the comparison of their idealized credit ratings to the Gas Group's average credit rating based on the <u>actual</u> financial performance of its members. NS-PGL Init. Br. at 87-92.

In an attempt to justify this comparison, Staff asserts that its "methodology is just as likely to produce an upward adjustment as a downward adjustment." Staff Rep. Br. at 41. This is simply wrong. Staff's hypothetical credit ratings assume zero risk to the Utilities' recovery of their revenue requirements, while the average Gas Group credit rating reflects those utilities' actual performance and actual recovery risk. The comparison is not only inapt, but also stacked against the Utilities. Tellingly, Staff fails to identify even one instance in which its methodology resulted in an upward adjustment of a utility's ROE.

Staff's claim that "Mr. Moul did not use a single measure of financial risk in his sample selection process" (Staff Reply Brief at 45) is also false. Mr. Moul fully explained his sample evaluation methodology, which included consideration of numerous financial risk factors including capital structure ratio, earnings quality, fixed charge coverages, IGF to construction ratios and credit ratings, in addition to operational risk factors. Moul Dir., PGL Ex. PRM-1.0 at 7:146 – 12:242; PGL Exs. PRM-1.2, PRM-1.3, PRM-1.4. It is Mr. McNally who ignored relevant risk factors. By focusing only on financial risk differentials between the Utilities and the Gas Group, he ignored operational risk differentials, which makes his analysis one-sided and therefore arbitrary. Moul Reb., NS-PGL Ex. PRM-2.0, 29:561 – 31:608.

A second and independently fatal flaw of Staff's methodology results if its financial risk adjustment – which already reflects zero risk to the utility's recovery of its revenue requirement in full – is added to downward adjustments for asserted reductions in the risk to the utility's revenue recovery due to riders, which in these cases include Riders VBA, UEA and, for Peoples Gas only, Rider ICR. The duplicative and punitive nature of making both types of adjustments is obvious. Staff's financial risk adjustment already assumes the existence of the equivalent of a "Super Rider" that ensures the utility full recovery of its revenue requirement. With such a figurative rider assumed in place, no other rider could have any further effect on the utility's revenue recovery or financial risk, and any additional adjustment to its authorized return would be duplicative and punitive.

In order to avoid duplicative and punitive adjustments to the Utilities' authorized returns in these cases, the Utilities offer the Commission two alternative compromise solutions. Given the basic flaws in Staff's financial risk adjustment, the Commission should reject it. Under "Alternative 2A," if the Commission concludes that approval of any or all of the Utilities' proposed riders will reduce their financial risk, then the Commission should apply only the specific adjustments for those riders as reflected in the Proposed Order, namely 10 basis points for Rider VBA, 10 basis points for Rider UEA and 163 basis points to the ROE factor of Peoples Gas' Rider ICR. Under "Alternative 2B," if the Commission nonetheless accepts Staff's financial risk adjustments, then the Commission should reject any additional adjustments for the riders.

EXCEPTION NO. 16

The changes offered in this Exception to the "Final Conclusions" and "Weighted Average Cost of Capital" sections of the Proposed Order reflect the Utilities' positions discussed above, including their alternative proposed solutions to the financial risk "double counting" issue. Under "Alternative 1", if the Commission adopts the Utilities' proposed 11.87% cost of equity, North Shore's weighted average cost of capital ("WACC") would 9.058% and Peoples Gas' WACC would be 8.970%. Under "Alternative 2A", if the Commission rejects Staff's financial risk adjustment and accepts Staff's rider adjustments, then the Utilities' authorized return on equity would be 10.61%, North Shore's WACC would be 8.353% and Peoples Gas' WACC would be 8.265%. Under "Alternative 2B", if the Commission accepts Staff's financial risk adjustment and rejects Staff's rider adjustments, then North Shore's authorized return on equity would be 10.61% and its WACC 8.353%, and Peoples Gas' authorized return on equity would be 10.51% and its WACC 8.209%.

VIII. PROPOSED RIDER ICR (PEOPLES GAS) – PART I

EXCEPTION NO. 17 *[Typographical error correction only]*

The Proposed Order fairly examines the evidence submitted and legal arguments made in support of and in opposition to Rider ICR and reaches the proper conclusions that the record evidence meets the standard set forth by the Commission for the approval of such an infrastructure initiative, that no legal barriers exist to the approval of Rider ICR, and that with Staff's proposed changes to the rider mechanism accepted by Peoples Gas, Rider ICR as proposed by Peoples Gas should be approved. Furthermore, the Proposed Order correctly found that Staff's proposals to require an accelerated program under 220 ILCS 5/8-503, to submit an implementation plan for approval in a separate docket with analysis by an outside consultant retained by the Commission and paid for by Peoples Gas, and to require periodic updates with analysis by an outside consultant retained by the Commission and paid for by Peoples Gas were unnecessary, devoid of a cost-benefit justification and, most importantly, not supported by the record evidence and, therefore, should not be accepted. As substantiated by the weight of evidence in the record, Rider ICR will help enable the acceleration of Peoples Gas' main replacement program, which will provide benefits to customers, employees, and the City in terms of improved safety, cost savings, reduced environmental impacts, increased and/or new functionalities and job creation. Accordingly, the Proposed Order correctly concludes that the record in this proceeding presents an appropriate circumstance for the Commission to properly and pragmatically exercise its legal authority to approve Rider ICR.

Therefore, the Utilities propose only a minor technical correction. The Proposed Order cites an incorrect page number when citing *Peoples 2007*. Thus, the Commission should adopt Exception No. 17.

VIII. <u>PROPOSED RIDER ICR (PEOPLES GAS) – PART II</u>

<u>EXCEPTION NO. 18</u> ***[Technical corrections only]***

The Utilities agree with the Proposed Order's well-reasoned conclusions with respect to Staff's proposals. However, the Utilities propose some minor corrections to the summary of the AG's position contained on pages 189 and 190 of the Proposed Order. The corrections are necessary to clarify that these statements are the AG's position and not what the record actually reflects. Thus, the Commission should adopt Exception No. 18.

XII. <u>RATE DESIGN</u>

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

2. <u>Account 904 Uncollectible Expense</u>

<u>EXCEPTION NO. 19</u>

The Proposed Order correctly concludes that, for Service Classification ("S.C.") Nos. 1 and 2, it is appropriate to differentiate for gas cost-related Account 904 ("Uncollectible Account") costs in the customer charges. ALJPO at 211-212. Differentiation recognizes that gas cost-related Account 904 costs differ for sales customers and transportation customers. Section XII(A)(2) of the Proposed Order does not address a cost of service question that Section XI(B)(1) of the Proposed Order deferred to this section. ALJPO at 199. Section XI(B)(1) of the Proposed Order concerned the proper classification of Account 904 costs in the Utilities' embedded cost of service studies ("ECOSS"). The ECOSS issue, while relevant to the rate design issue, is distinct. The Account 904 classification was a key factor in the

Utilities' rate design proposal to differentiate for gas cost-related Account 904 costs in the customer charges. NS-PGL Init. Br. at 138-141. Section XII(A)(2)(a) of the Proposed Order accurately describes the Utilities' rationale for its functionalization, classification and allocation of Account 904 costs (*i.e.*, the ECOSS issue). ALJPO at 205-208. What is missing is resolution of this contested issue in the Commission Analysis and Conclusion.

Additionally, the Commission Analysis and Conclusion may be confusing in its description of the Utilities' last rate cases. In *Peoples 2007*, the Commission approved differentiation, and its reasoning for doing so applies fully to the current cases. *Peoples 2007* at 230. The Commission, however, required the differentiation in the distribution charge, unlike the conclusion properly reached in the Proposed Order to reflect differentiation in the customer charges. *Id*. The revisions to the Proposed Order address both the ECOSS issue and clarify the description of the *Peoples 2007* Order.

B. SERVICE CLASSIFICATION RATE DESIGN

2. Contested Issues

c. Demand Rates

EXCEPTION NO. 20

The Proposed Order adopts AG-CUB-City witness Mr. Rubin's demand rates (ALJPO at 228), which is a flawed S.C. No. 1 rate design. His demand rates place too much cost recovery in the second block of the distribution charge, and they have an unnecessarily large impact on high usage customers.

The Proposed Order incorrectly concludes, that, under the Utilities' proposal, demand-related charges do not vary with usage. In fact, all demand costs are recovered through distribution charges, *i.e.*, volumetric charges. Grace Dir., NS Ex. VG-1.0 Rev. at 13:271-273;

Grace Dir., PGL Ex. VG-1.0 Rev. at 14:306-308. The Utilities each proposed to maintain a declining two-block S.C. No. 1 distribution charge. For North Shore, the first block (0 to 50 therms) would recover two-thirds of demand, commodity and remaining customer costs and the second block (over 50 therms) would recover the remaining costs. Grace Dir., NS Ex. VG-1.0 Rev. at 12:255 - 14:290. Similarly for Peoples Gas, the first block (0 to 50 therms) would recover 65% of demand, commodity and remaining customer costs and the second block (over 50 therms) would recover the remaining costs. Grace Dir., PGL Ex. VG-1.0 Rev. at 13:285 - 15:325.

Mr. Rubin's design would recover all demand-related costs on an equal cents per therm basis for both blocks. This incorrectly infers that demand-related costs are volumetrically based. No party contested the Utilities' average and peak ("A&P") methodology to allocate demand-related costs in their ECOSSs. The A&P method allocates most costs based on peak day usage and a lesser amount based on average usage. Demand costs are fixed costs. Absent a fixed demand charge, which is not part of Mr. Rubin's proposal, demand-related costs should be recovered through a fixed charge, such as the customer charge, or spread between the customer and commodity charges. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 31:680 - 32:701. The Utilities' proposed distribution charges with more costs in the front block, unlike Mr. Rubin's demand rates, are consistent with the A&P methodology and cost causation principles.

Also, Mr. Rubin's proposal disproportionately affects high use customers. Compared with Peoples Gas' proposal, bills for high use customers would be about 26% higher. For North Shore, the impact is about 126% higher. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 29:643 - 30:661. The Proposed Order does not address this adverse bill impact.

In the alternative, if the Proposed Order's conclusion to adopt Mr. Rubin's demand-based rates stands, it should be clear that this proposal affects the calculation of the distribution charges only and not the calculation of the customer charges. The Proposed Order addresses the S.C. No. 1 customer charges in Section XII(B)(2)(a), where it correctly concludes that the Utilities' proposed increase in the amount of fixed costs recovered through the customer charges is appropriate. ALJPO at 220. This conclusion should be stated in the adoption of demand-based rates. Additionally, the erroneous statement that the Utilities' current and proposed rates provide that demand-related charges do not vary with usage should be stricken.

XIII. TRANSPORTATION ISSUES

C. Large Volume Transportation Program

1. Super Pooling on Critical Days

EXCEPTION NO. 21

The Proposed Order adopts Constellation NewEnergy - Gas Division, LLC's ("CNE-Gas") recommendation that the Utilities permit "super pooling" on Critical Days such that the Utilities would waive penalty charges "if after the Critical Day, a supplier is able to show that, in aggregate, its pools have excess deliveries of sufficient quantity to alleviate all, or a portion of, any incremental charges and penalties incurred." ALJPO at 243. Prior to issuance of the Proposed Order, the Utilities discussed super pooling with CNE-Gas. The Utilities proposed a method under which suppliers would be able to take steps to reduce or avoid penalty charges on Critical Days. This method differs somewhat from CNE-Gas' proposal, but it accomplishes the same objective. The Utilities understand that CNE-Gas found the proposal acceptable and that CNE-Gas plans to address the proposal in its brief on exceptions.

The proposal applies to Critical Days, which means that it applies to Rider SST customers and suppliers serving Rider SST customers under Rider P[32], as Critical Days have no adverse effect on Rider FST. When the Utilities declare a Critical Day, suppliers would have the opportunity to notify the Utilities, in writing by the first business day of the month following the Critical Day, that they intend to participate in a Critical Day Reallocation. "Reallocation" means that a supplier may, after-the-fact, move gas that it delivered to one or more of its Rider SST pools on a Critical Day to another one or more of its Rider SST pools. For example, assume a supplier has three Rider SST pools and delivered 100 units to each pool on a Critical Supply Shortage Day. One pool incurs unauthorized use charges that delivery of an additional 25 units would have avoided while the other two pools incurred no such charges and, in fact, had sufficient deliveries on that day that each could transfer (reallocate) deliveries to the first pool and still incur no unauthorized use charges. To illustrate:

Supplier A's Rider SST Pools	Critical Day Deliveries	Quantity Needed to Avoid Unauthorized Charges	After-the-Fact Reallocation	Adjusted Critical Day Deliveries
Pool 1	100	125	receive 25 from Pools 2 and 3	125
Pool 2	100	85	transfer 15 to Pool 1	85
Pool 3	100	90	transfer 10 to Pool 1	90

The reallocation will occur after the Utilities reconcile consumption for the month in which a Critical Day(s) occurred. Suppliers would determine what reallocation of deliveries, if any, they

[32] The Proposed Order erroneously references Rider 13 Groups. The Utilities' tariffs do not include a Rider 13.

will request for a given Critical Day(s). The supplier must submit, in writing, its reallocation. The Utilities would execute the reallocations prior to billing the month in which the Critical Day(s) occurred. This method gives suppliers the tools to avoid Critical Day unauthorized use charges through delivery reallocations that the suppliers choose. As such, it meets the goals of "super pooling."

In the alternative, if the Commission rejects this method for implementing CNE-Gas' proposal, the Utilities continue to oppose CNE-Gas' proposal for the reasons stated in their briefs. NS-PGL Init. Br. at 174-176; NS-PGL Rep. Br. at 104-106.

D. <u>Small Volume Transportation Program</u>

1. <u>Allocation of and Access to Company-Owned Assets</u>

<u>EXCEPTION NO. 22</u>

The Proposed Order adopts, for each of the Retail Gas Suppliers' ("RGS") recommendations, including the storage issues raised in Section XIII(D)(1), Staff's proposal to hold workshops to address the Utilities' Choices For You^{sm} ("CFY") program for small volume transportation customers and alternative suppliers. ALJPO at 256, 258, 263, 269, 272, 274, 275. RGS failed to show that changes to the CFY programs are warranted and, consequently, mandating workshops is inappropriate. To narrow the issues, the Utilities do not except to the Proposed Order's requirement that Staff convene workshops, including the proviso that the "workshops (*sic*) participants shall be technical and other in-house working personnel from the affected companies and the Commission Staff." ALJPO at 256.

The Utilities do except to the language mandating and describing the workshops. The Proposed Order incorrectly concludes that "it is clear that changes to the CFY program are needed." *Id.* The purpose of the workshops should be to determine what, if any, changes are required and not to prejudge the outcome of those workshops, given the deficiencies in RGS' evidence. NS-PGL Init. Br. at 176-184; NS-PGL Rep. Br. at 107-117. In particular, the Proposed Order appears to rely on the level of CFY participation as support for the conclusion that "changes are required." First, there is no record support that the design of the CFY program is the sole or primary driver of participation levels. Second, nothing in the record supports, nor does the Proposed Order cite any authority for, presupposing that a high level of participation in a small volume transportation program is Commission policy or a Commission objective. Third, if it is the Commission's determination that higher participation in such programs is desirable, it should be clear that achieving such higher participation should not be at the expense of (*i.e.*, subsidized by) customers who elect not to participate. *See, e.g.,* Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 64:1407-1417.

Additionally, the Proposed Order directs the Utilities "to come to the workshops prepared to discuss the Nicor program." ALJPO at 256. The Utilities can be prepared to discuss Nicor's tariffs on file with the Commission. If that is what the Proposed Order requires, the Utilities do not oppose it, but the language should be clear. However, the Utilities cannot commit to be prepared to discuss how Nicor administers the program. If the Proposed Order imposes this more expansive requirement, it is inappropriate. Unlike the tariff, many facets of the Nicor program are not necessarily something the Utilities can be required to discuss with authority. Such facets include how Nicor administers its program; what computer programming it has in place; how, if at all, its small volume program relates to its large volume program; how its gas supply and gas control personnel manage Nicor's transmission and distributions system; and how Nicor manages its storage fields.

Finally, the purpose of the workshops should be clearer. For example, some issues affect base rates (whether to recover administrative costs from all customers or from CFY suppliers) and, if a proposal to change results from the workshops, it could only be implemented in a rate case. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 64:1407-1417. Other issues, such as administrative requirements, may result in process changes that can occur through a tariff filing outside of a rate case or, perhaps, without a tariff filing. These outcomes should be acknowledged in the Order.

3. Allocation of Administrative Costs and Related Charges

EXCEPTION NO. 23

The Proposed Order deferred to workshops the issue of whether certain administrative costs should be recovered through base rates. ALJPO at 263. Having deferred the issue, it should be clear that compliance rates in this proceeding will be based on the Utilities' proposals to recover such costs through specific charges assessed to suppliers. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 64:1407-1417. This is consistent with the Proposed Order's treatment of RGS' proposal related to reducing the Aggregation Balance Gas Charge. ALJPO at 258 ("With respect to the proposed reduction to the ABGC, it is here denied.").

XIV. FINDING AND ORDERING PARAGRAPHS

Finding and Ordering Paragraphs (7), (8), (9), (10), (11), (12), (17), and (18) should be revised for the reasons stated earlier in the Brief on Exceptions as to Exception Nos. 1 through 16 as applicable.

The Ordering Paragraph corresponding to Finding Paragraph (28) should be revised for the reasons stated earlier in this Brief on Exceptions as to Exception No. 21.

APPENDIX A

Appendix A should be revised for the reasons indicated for adoption of, and consistent with, Exceptions Nos. 1 through 16, discussed above. [33]

APPENDIX B

Appendix B should be revised for the reasons indicated for adoption of, and consistent with, Exceptions Nos. 1 through 16, discussed above.[34]

In addition, Appendix B contains a very minor allocation error. Appendix B on page 2, column (l) shows an adjustment of $9,000 for company use gas to Distribution expenses, but it should be split $2,000 to Other Production Expenses and $7,000 to Distribution Expenses. NS-PGL Exs. CMG-3.2N, SM-3.2N. That slight difference is rolled up in the aggregate figures on lines 8 and 9 of page 1 of Appendix B, so the same split should be reflected there as well.

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[33] As noted earlier in this Brief on Exceptions: The NS-PGL Exceptions address revised language of the narrative portion of the Proposed Order. North Shore's and Peoples Gas' proposed revisions to the rate base and operating income Schedules in Appendices A and B of the Proposed Order in effect are set forth in the rate base and operating income Schedules attached to the respective surrebuttal testimony of Utilities' witnesses Ms. Moy and Mr. Hengtgen (NS-PGL Ex. SM-3.1N, SM-3.1P, JH-3.1N, JH-3.1P), because the latter Schedules reflect the results of adoption of the Utilities' Exceptions, subject only to the limited modifications referenced in fn. 16, *supra.*

[34] See fn. 33, *supra*.

TECHNICAL EXCEPTIONS

A. Section V.B.2 – Uncontested Issues Union Wages

TECHNICAL EXCEPTION NO. TC-1

In Section V.B.2, Operating Expenses – Uncontested Issues – Union Wages, the Proposed Order (at 38) addresses both the adjustments to the Utilities' operating expenses and rate base. However, in Section IV.B.2.(b), Rate Base – Uncontested Issues – Capitalized Union Wages, the Proposed Order (at 9) already addresses the rate base portions of these adjustments. Therefore, the Utilities respectfully recommend that the references to the rate base portions of this adjustment be stricken on page 38. Accordingly, the Proposed Order should be revised as shown in Technical Exception No. TC-1 in the NS-PGL Exceptions.

B. Section V.B.7.(f) – Operating Expenses - Uncontested Issues – Civic, Political, and Related Activities

TECHNICAL EXCEPTION NO. TC-2

In Section V.B.7.(f), Operating Expenses – Uncontested Issues – Civic, Political and Related Activities, the Proposed Order (at 42) addresses both the adjustments to the Utilities' operating expenses and rate base. However, in Section IV.B.2.(c), Rate Base – Uncontested Issues – Capitalized Civic, Political, and Related Activities, the Proposed Order (at 9) already addresses the rate base portion of this adjustment. Therefore, the Utilities respectfully recommend that the references to the rate base portion of this adjustment be stricken. Accordingly, the Proposed Order should be revised as shown in Technical Exception No. TC-2 in the NS-PGL Exceptions.

C. Section V.B.7.(i) – Operating Expenses – Uncontested Issues – Rate Case Expenses

TECHNICAL EXCEPTION NO. TC-3

In the Proposed Order's Section V.B.7.(i)(1), Operating Expenses – Uncontested Issues – Rate Case Expenses (ALJPO at 43), the description of the record evidence appears to inadvertently include several extraneous words. The Utilities respectfully recommend that the phrase "The Companies' total outside costs" that begins the first sentence under Section V.B.7.(i)(1) be stricken. Accordingly, the Proposed Order should be revised as shown in Exception No. TC-3 in the NS-PGL Exceptions.

TABLE OF PAGES WHERE EXCEPTIONS APPEAR IN EXCEPTIONS VERSION OF PROPOSED ORDER

As noted on the first page of this brief, the Utilities' Exceptions language appears in a separately filed Exceptions to the Proposed Order that contains proposed revised Order language in black-lined format. For ease of reference, the following table sets forth the Exceptions and the pages on which they may be found in the Exceptions version of the Proposed Order.

Exception Nos.	Pages in Exceptions Version of Proposed Order
1	7, 281, 282
2	7–8, 281, 282
3	8, 280
4	8, 280
5	18-19
6	36-37
7	38-39
TC-1	39-40
TC-2	42-43
TC-3	43
8	59-62
9	90-92
10	92-93
11	100-101, 280-281
12	102, 280-281

13	125, 280-281
14	126-130, 280-281
15	130-133, 280-281
16	133-137, 280-281
17	173
18	195
19	215-216
20	231-233
21	244-245, 247-248, 284
22	260-261
23	268

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