**STATE OF ILLINOIS**

**ILLINOIS COMMERCE COMMISSION**

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

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


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

North Shore Gas Company ("North Shore") and The Peoples Gas Light and Coke Company ("Peoples Gas") (together the "Utilities"), by their counsel, pursuant to the Administrative Law Judges' Order Regarding Case Management Plan and Schedule of April 27, 2009, submit this Initial Post-Hearing Brief.

# I. INTRODUCTION

## A. Overview / Summary

### 1. Overview

The Utilities are before the Illinois Commerce Commission (the "Commission" or "ICC") for three primary reasons: (1) their existing rates do not allow the Utilities to recover their costs of service; (2) they propose new riders, especially Peoples Gas' proposed infrastructure improvement cost recovery rider, "Rider ICR"; and (3) their rate designs and charges should be updated.

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 in 2008, and they are faced with increased costs that are leading to increasing cost recovery shortfalls, despite their having taken extraordinary cost control measures that are reflected in their final revised proposals in these cases. For example:

- The Utilities, under existing rates, are significantly under-recovering their operating expenses. Their existing rates set in February 2008 are based on operating expenses before income taxes of $325,582,000 for Peoples Gas and $42,895,000 for North Shore.[1] Their final revised operating expenses before income taxes in 2010 are forecasted, however, to be $403,231,000 and $59,946,000, respectively.[2] Those shortfalls make up the bulk of the Utilities' test year cost recovery shortfalls (their "revenue deficiencies").
- The Utilities, under existing rates, 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.[3] In 2010, under existing rates, Peoples Gas will be recovering an overall rate of return of just 4.00%, and North Shore will be recovering an overall rate of return of just 3.04%,[4] even though their costs of capital have increased significantly with the financial crisis of Fall 2008 and the subsequent recession.

---

[1] *In re North Shore Gas Co., et al.*, ICC Docket Nos. 07-0241/07-0242 Cons. (Order Feb. 4, 2008) ("*Peoples 2007*") at Appendix ("App.") A, p. 1., line 19, col. (i), and App. B, p. 1, line 19, col. (i).

[2] North Shore and Peoples Gas ("NS-PGL") Exhibit ("Ex"). SM-3.1P at Schedule ("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).

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

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

Such drastic under-recoveries jeopardize the long-term interests of customers and the Utilities.

Apart from rectifying the under-recovery of the Utilities' costs of service, the Commission also should approve Peoples Gas' proposal to recover via a rider the costs of accelerated replacement of cast and ductile iron gas main in the City of Chicago. In the Utilities' last rate cases, the Commission did not approve such a rider, but rather set out its road map for approval of such a rider. *Peoples 2007* at 162. Peoples Gas has followed that road map. Based on the detailed supporting testimony, the Commission should now approve the proposed rider.

Finally, the Utilities have presented appropriately updated rate designs and charges and taken reasonable positions on the other tariff issues that have been raised.

### 2. The Utilities' Existing Rates Do Not Allow Them to Recover Their Costs of Service

#### a. The Utilities' Are Experiencing Increasing Cost Recovery Shortfalls

The Utilities' under-recoveries of their costs of service are significant and increasing. Under their final revised calculations, North Shore's under-recovery of its costs of service (its revenue deficiency) in 2010 is expected to be $18,105,000, and Peoples Gas' cost recovery shortfall is expected to be $113,178,000. Moy Surrebuttal ("Sur."), NS-PGL Ex. SM-3.0 at 3:50-54; NS-PGL Ex. SM-3.1N at Sched. C-1, line 3; NS-PGL Ex. SM-3.1P at Sched. C-1, line 3. Due to their costs control measures and their agreement with or acceptance of various adjustments, North Shore's figure has decreased by nearly 18% and Peoples Gas' figure has decreased by over 30% since these cases were filed. *Compare* above with NS Ex. SM-1.1 at Sched. C-1, line 1; PGL Ex. SM-1.1 at Sched. C-1, line 1.

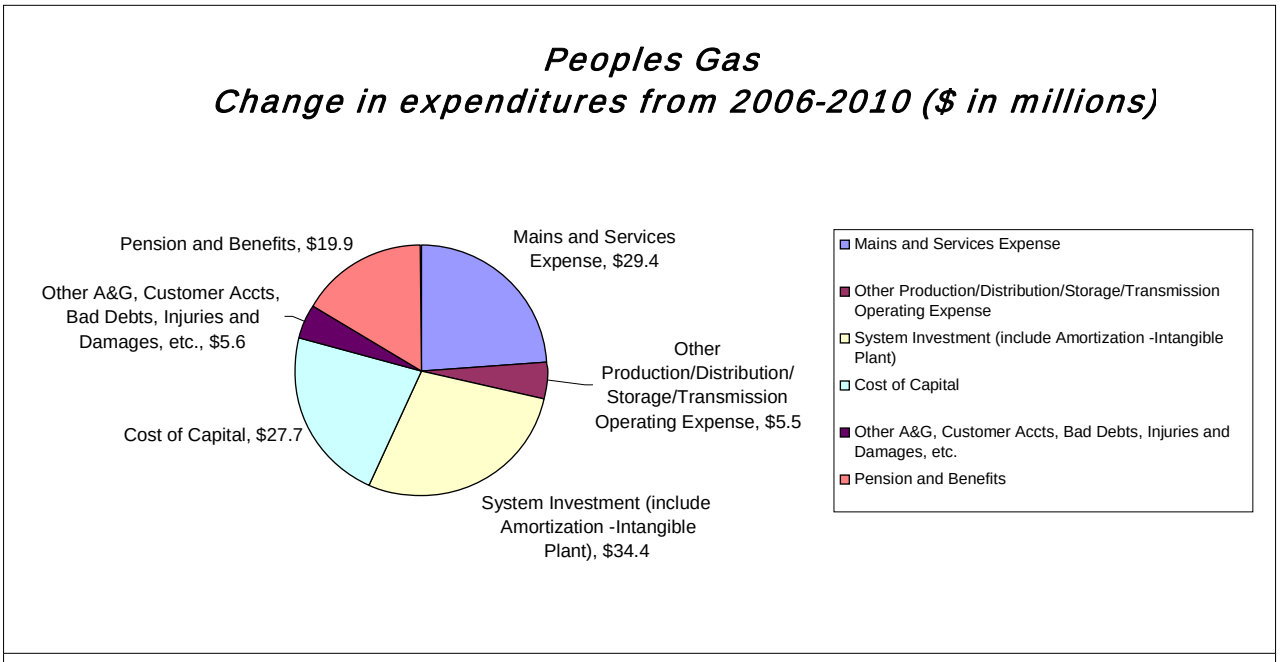
The primary driver of the Utilities' increasing cost recovery shortfalls is their increase in operating expenses before income taxes, as noted above and discussed further detail below.

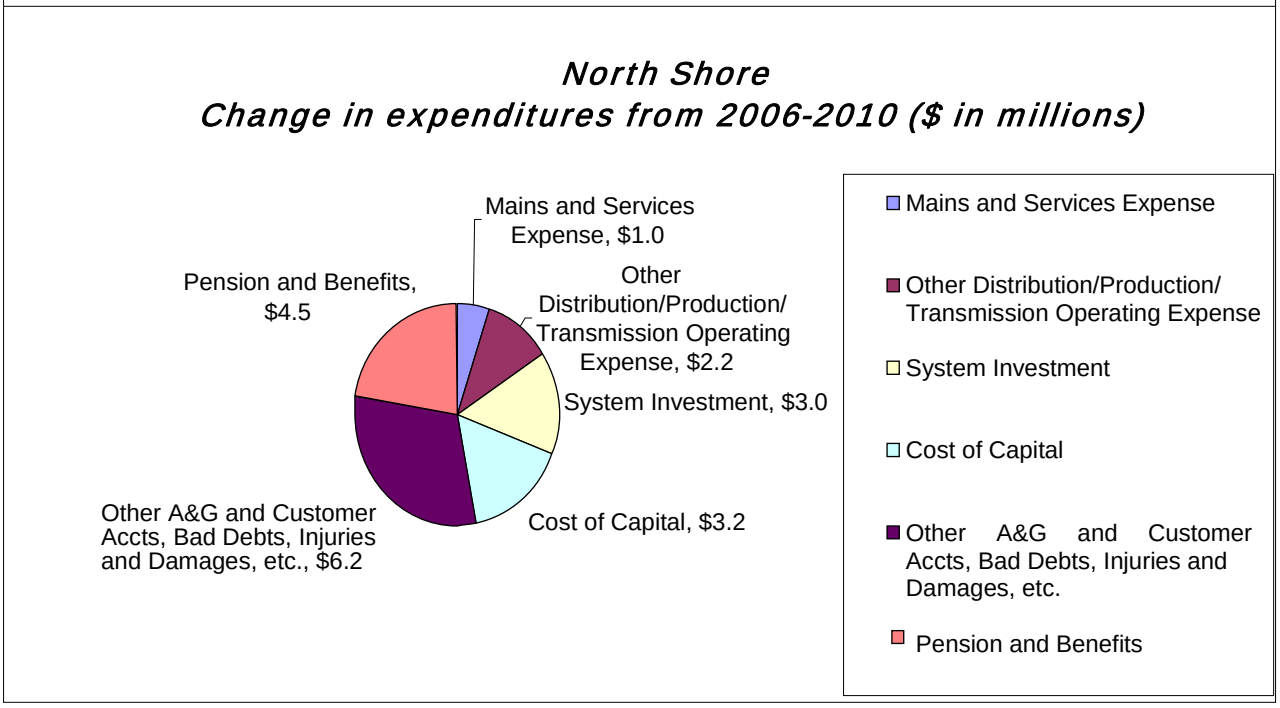
Peoples Gas' and North Shore's existing rates assume operating expenses before income taxes of $325,582,000 and $42,895,000, but their final revised operating expenses before income taxes in 2010 are forecasted to be $403,231,000 and $59,946,000, respectively, as noted earlier.[5]

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 reflecting in full the cost control measures they adopted due to the financial crisis. 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 customer-related expenses is the primary driver, followed by increased pensions and benefits expenses, increased costs of capital, and investments in its system. The drivers are quantified in the following charts from page 11 of Mr. Schott's rebuttal testimony.

[5] *See* fn. 1 and 2, *supra*.




In 2008, despite the new rates, which 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. In 2008, despite the new rates, which 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.

As the Utilities continue to invest in their systems, Peoples Gas was forecasted to earn an ROE of only 3.2% in 2009 and only 0.3% in 2010, while North Shore was forecasted to earn ROEs of only 3.5% and only 1.1% in 2009 and 2010, as of their direct cases, respectively. Johnson Dir., PGL Ex. BAJ-1.0 at 4:70; Johnson Dir., NS Ex. BAJ-1.0 at 4:69. As noted earlier, even though, in February 2008, the Commission approved rates intended to result in overall rates of return of 7.76% and 7.96%, Peoples Gas is expected to recover an overall rate of return of just 4.00% in 2010, and North Shore just 3.04%.[6]

Nonetheless, Commission Staff ("Staff") and certain intervenors propose to sharply reduce the Utilities' revenue requirements (their total base rate costs of service) and rate increases by proposing a wide array of adjustments. The Utilities have agreed to, or accepted in order to narrow the issues, a great number of rate base and operating expenses adjustments, as noted in Section III and illustrated in Sections IV and V of this Initial Brief. They also have reduced their proposed rates of return, as discussed in Section VI. However, the remaining contested adjustments are incorrect and should not be adopted.

Many similar types of adjustments were proposed by Staff and intervenors in the Utilities' 2007 rate cases. We have seen the severe cost under-recoveries that followed. In the remainder of this portion of this Introduction, the Utilities will give an overview on the five contested adjustments with the largest financial impacts (not in the rank order of those impacts).

**Rates of Return**. Since the Utilities' last rate cases, the national and international economies have plunged into both the worst economic recession and the most volatile period of

[6] *See* fn. 3 and 4, *supra*.

financial instability since the Great Depression. The resulting flight of capital from the financial markets has caused debt costs to climb, stock prices to fall, and the government to offer its securities at nearly zero cost. These developments translate to a significant increase in risk and cost associated with just about any type of investment, including investments in the Utilities.

Steven Fetter, former chairman of the Michigan Public Service Commission and Managing Director of Fitch, Inc.'s Global Power Group, cogently summarized what is at stake:

> I believe the financial community viewed the result in the Utilities' last rate cases as a relatively constructive decision from the ICC. However, that optimism has not continued. Both S&P and Moody's recently downgraded the Utilities and assigned negative outlooks. In my opinion, further reducing the Utilities' ROEs, as recommended by the Staff and intervenors in this proceeding, would be viewed as a major setback, leaving the authorized ROEs at virtually the bottom of the regulated utility universe.

Fetter Reb., NS-PGL Ex. SMF-1.0 at 12:248 – 13:254.

Now would be precisely the <u>wrong</u> time for the Commission to send a negative regulatory signal to the markets. "With [their] current split rating between the 'A' and 'BBB' categories, any negative credit rating action for the Utilities could have increasingly harmful financial effects." *Id.* at 17:359-361. That is because BBB-rated public utilities have experienced unprecedented escalation in capital costs since last fall's financial crisis, as shown by the extraordinarily large spreads between Treasuries and utility debt and between A-rated and BBB-rated unsecured utility debt. *Id.* at 18:374 (table); *see also* Fetter, Tr. 511:3 – 512:17.

If the Utilities were further downgraded, the financial harm could be long-term because credit ratings are based on prevailing and forecasted factors. Even if the Utilities were able to recover their financial metrics quickly, the rating agencies would need to see evidence of prolonged financial strength to reverse the downgrade. Fetter Reb., NS-PGL Ex. SMF-1.0 at 19:389 – 20:402.

The financial crisis and subsequent recession have unquestionably caused the Utilities' cost of capital to increase since their last rate cases were decided in early 2008. Peoples Gas' debt cost has increased by 91 basis points (from 4.67% to 5.58%), and North Shore's by 9 basis points (from 5.39% to 5.48%). NS-PGL Ex. BAJ-2.1N; NS-PGL Ex. BAJ-3.1P.[7]

According to the analyses performed by the Utilities and Staff, the Utilities' cost of equity capital also has increased. The following table compares the Utilities' and Staff's unadjusted financial model results in the Utilities' last rate cases to their results in these cases. With the exception of Staff's CAPM results, the results uniformly show an increase in the Utilities' cost of equity, and in some cases a significant increase:

| Financial Model | 2007[8] | 2009 | Difference |
|---|---|---|---|
| Utility Constant Growth DCF | 9.01 | 10.67 | +166 BP |
| Utility CAPM | 10.79 | 10.86 | +7 BP |
| Utility Risk Premium | 11.25 | 12.25 | +100 BP |
| Staff Constant Growth DCF[9] | 8.23 | 11.76 | +353 BP |
| Staff Non-Constant Growth DCF | 10.23 | | N/A |
| Staff CAPM | 11.34 | 9.95 | -138 BP |

[7] Staff has Peoples Gas' long-term debt cost at 5.28%, which would represent an increase of 61 basis points. Kight-Garlisch Reb., Staff Ex. 22.0 at Sched. 22.4P.

[8] NS-PGL Brief on Exceptions, Attachment 1, ICC Docket Nos. 07-0241/07-0242/Cons. (Dec. 14, 2007). The Commission relied on that attachment in setting the Utilities' current authorized ROEs. *Peoples 2007* at 100.

[9] As discussed below, Staff did not use a constant growth DCF model in this case, but rather a non-constant growth DCF model. However, Mr. Moul calculated the result of using Staff's constant growth DCF model from the Utilities' last rate cases with Staff's DCF model inputs in these cases. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 14:290-292. Because Staff did not present a non-constant growth DCF result in the Utilities' last rate cases, there is no result to compare to Staff's non-constant growth DCF result in these cases. Likewise, CUB-City presented a constant growth DCF result in the Utilities' last rate cases and a non-constant growth DCF result in these cases. These results are not directly comparable, but it is noteworthy that CUB-City's DCF result increased from 8.11% to 8.58% despite the switch to a non-constant growth model that assumed lower growth rates in future periods.

The Commission's authorized returns since the Utilities' last rate cases likewise show a general trend of increasing public utility costs of equity:[10]

| Utility | Date | ROE |
|---|---|---|
| North Shore | 2/5/08 | 9.99 |
| Peoples Gas | 2/5/08 | 10.19 |
| ComEd | 9/10/08 | 10.30 |
| Ameren (electric) | 9/24/08 | 10.65 |
| Ameren (gas) | 9/24/08 | 10.68 |
| Nicor Gas | 3/25/09 | 10.17 |
| Illinois Gas | 5/13/09 | 10.94 |

The Commission's recent authorized returns on equity are in line with those awarded energy utilities in other states so far in 2009. The median of those awards is 10.50%. Fetter Reb., NS-PGL Ex. SMF-1.0 at 7:135 (table) and 10:197.[11] The average of those awards is 10.36% Fetter, Tr. at 483:16-21.

Consistent with this backdrop, the Utilities request an increase in their authorized ROEs to their final revised figure of 11.87%. Although this rate is at the high end of recent returns, it reflects the Utilities' increased risk in the midst of an economic recession and is well within the range of returns this Commission has issued over the last 30-odd years.[12]

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[10] ICC Financial Analysis Div., *Rate Case Histories* (Sept. 2009) (based on Commission final Orders).

[11] This Commission's May 2009 decision on Illinois Gas approving an ROE of 10.94% is not included in these data. *In re Illinois Gas Co.*, ICC Docket No. 08-0482 (Order May 13, 2009) at 19.

[12] *See* fn. 10, *supra*.

By contrast, according to Staff and CUB-City,[13] the Utilities' cost of equity has decreased since their last rate cases, despite the financial crisis and recession. Staff recommends that the Commission reduce the Utilities' ROEs below 10%, to 9.79% for North Shore and 9.69% for Peoples Gas. McNally Dir., Staff Ex. 7.0 at 21:395-412. CUB-City's recommendation is a mere 8.255%. These recommendations lie at the low end of the range of recent returns issued by other state commissions, and are below any rate of return that this Commission has set for any gas utility since at least 1972. Fetter Sur., NS-PGL Ex. SMF-2.0 at 9:189-203.[14]

With the possible exception of CUB-City witness Mr. Bodmer, all agree that determination of a public utility's ROE involves a mixture of science and art, objectivity and subjectivity. *See* Moul Sur., NS-PGL Ex. PRM-3.0 Rev. at 15:342 – 16:350; McNally, Tr. 696:11 – 697:8. The financial models provide a common set of methodologies developed and tested over decades of academic thinking and research. However, the models are only as good as the inputs and the adjustments to them. No analyst's ROE result can be free from some level of subjectivity. The true test of reasonableness is how the analyst's result fares in the context in which it is made.

Against this standard, the Staff and CUB-City recommendations cannot be squared with everything we know about the state of the financial markets and the economy in general, and therefore reflect serious methodological flaws, excessive subjectivity, or both. In fact, their recommendations reflect the value-laden judgments that infuse the underlying analyses. In many instances, these analysts reject objective data that investors routinely rely upon in favor of assumptions that the analysts believe are more reasonable. Indeed, CUB-City's position that the

[13] The Citizens Utility Board ("CUB") and the City of Chicago ("City").

[14] *See* fn. 10, *supra*.

Utilities' ROEs should be set at around 8% reflects the new, extreme and value-laden approach advocated by Mr. Bodmer by which the Commission would set returns based not on investor-required returns at all but on the returns that the Commission decides investors should be satisfied with.

For these reasons, the Staff and CUB-City recommendations should be rejected because they stray from a zone of reasonableness to the degree that they offer unreliable estimates of the appropriate ROE. *See Peoples 2007* at 92. For the reasons set forth in Section VI of this Initial Brief, below, the Utilities urge the Commission to base the Utilities' authorized rates of return on equity on the Utilities' analyses, which support a final revised ROE of 11.87%.

**Peoples Gas Pension Asset**. Staff seeks to reduce Peoples Gas' rate base by $95,765,000, by eliminating the utility's pension asset from rate base. *E.g.*, Hathhorn Reb, Staff Ex. 15.0 at Sched. 15.4 P Corr., p.1, col. (d). Staff inconsistently also seeks to reduce North Shore's rate base by including its pension liability and to decrease both utilities' rate bases by including their other post-employment benefits ("OPEB") liabilities. AG[15]-CUB take those same positions, except they, unlike Staff, do not propose asymmetrical treatment of Peoples Gas' pension asset and North Shore's pension liability. The Staff and AG-CUB theory that customers paid for the pension asset is incorrect. Staff and AG-CUB's arguments against inclusion of the pension asset are based on faulty assumptions and are not supported by the evidence.

The impact on the utility and its shareholders of making such a large deduction from rate base is enormous. Disallowance in this case would effectively reduce Peoples Gas' overall rate of return by roughly 67 basis points and its ROE by roughly 120 basis points.[16] By effectively

[15] The Illinois Attorney General's Office (the "AG").

[16] 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 revised proposed ROR and ROE.

denying the Utilities an opportunity to recover their costs and earn their authorized returns, this adjustment is contrary to Illinois law. Peoples Gas recognizes that the Commission ruled against it on this issue in the 2007 rate cases, but the evidence in the instant cases does not support making the same ruling again. The Commission should not disallow the pension asset.

**Costs Related to the Liberty Audit (Peoples Gas)**. In ICC Docket No. 06-0311, the Commission found that Peoples Gas needed to improve its corrosion protection activities. Pursuant to a stipulation, the Commission ordered the hiring of a consultant to analyze Peoples Gas' practices, and Peoples Gas to track "any incremental costs caused solely by violation of the Illinois Gas Pipeline Safety Act … discovered by the Commission's consultant … which are over and above the prudent and reasonable costs necessary to comply with the Act."[17] In response to the subsequent audit, Peoples Gas took prudent and reasonable steps to achieve compliance with the Pipeline Safety Act. The record contains no evidence of costs caused solely by violations, only costs caused by compliance. Staff has misconceived and misapplied the standards for cost recovery under the law and the Order in Docket No. 06-0311. Moreover, Staff's suggestion that the Commission simply assume that 5% of all of Peoples Gas' test year distribution expense ($4,961,000) is caused solely by violations and must be excluded is arbitrary and unsupportable.

**Incentive Compensation Costs**. Staff and AG-CUB once again seek to disallow incentive compensation costs despite uncontradicted evidence that the costs are prudent and reasonable and benefit customers. Staff seeks to disallow $11,249,000 ($10,568,000 of

[17] *Illinois Commerce Comm'n on its Own Motion v. The Peoples Gas Light and Coke Co.,* ICC Docket No. 06-0311 (Order Dec. 20, 1006) at 6.

operating expenses and $681,000 in rate base).[18] The evidence from the only human resources expert who testified in these cases shows that: (1) the total compensation (including base pay, incentive pay, and other benefits) paid by the Utilities is prudent and reasonable; and (2) the design of the plans is prudent and reasonable, with both total compensation and the plans being carefully designed to attract and retain a qualified, sufficient, and motivated work force, which benefits customers. There is no sound basis for disallowing these costs.

**Cash Working Capital**. To determine the cash requirements caused by the timing of receipts and expenses, the Utilities performed a lead-lag study closely conforming to the methodology adopted by the Commission in the 2007 rate cases. Hengtgen Dir., PGL Ex. JH-1.0 at 20:439-446; Hengtgen Dir., NS Ex. JH-1.0 at 17:359-366. Staff, however, proposes to change the methodology, causing a large and unsubstantiated disallowance. Staff's proposal – to arbitrarily assign a revenue lag of zero days to pass-through taxes and energy assistance charges – is improper. Staff bases its argument in large part on Nicor Gas' most recent rate case, in which zero revenue lag days were used for pass-through taxes.[19] Nicor Gas, however, reportedly based its payments on actual collections from customers. Hengtgen Sur., NS-PGL Ex. JH-3.0 at 8:170 - 9:172, 9:192 - 10:194. Here, the Utilities' remit pass-through taxes to their municipalities based on estimates, with the taxes being paid whether or not actually received from customers. *Id*. at 9:173 - 10:198. Staff's proposal to use zero lag days for pass-through

[18] Hathhorn Reb., Staff Ex. 15.0 at Sched. 15.2 P, p.1, col. (c), Sched. 15.4 P, p. 1, col. (b), Sched. 15.2 N, p. 1, col (c), and Sched. 15.4 P, p. 1, col. (b). AG-CUB seeks to disallow a smaller net amount.

[19] *In re Northern Illinois Gas Company d/b/a Nicor Gas Company*, ICC Docket No. 08-0363, at 12-13 (Order March 25, 2009) ("*Nicor 2008*").

taxes is the reason for a large, inappropriate downward adjustment of $30,743,000 for Peoples Gas and $2,264,000 for North Shore.[20] Staff's proposal is improper and should be rejected.

The Commission should not adopt erroneous adjustments that prevent the Utilities from recovering their costs of service. The Commission should approve the Utilities' final revised proposed revenue requirements set forth in Section III, *infra*.

**b. The Commission Must Establish Rates That Allow the Utilities the Opportunity To Recover Fully Their Costs of Service, Including Fair Rates of Return**

The Commission, in a rate case, is required to establish rates that allow a utility the opportunity to recover fully its costs of service, including a fair and reasonable rate of return on its investments. Establishing rates that allow the opportunity for full cost recovery not only is a legal mandate, it is also in the long-term interests of customers.

**Cost Recovery**. A public utility has the right under long-established federal and Illinois constitutional law to rates that allow it the opportunity to obtain full recovery of its prudent and reasonable costs of service, including a fair return on its investment, *i.e.*, its revenue requirement. *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).

A public utility has the right under Illinois ratemaking law as well to rates that allow it the opportunity to obtain full recovery of its costs of service. *E.g., Commonwealth Edison Co. v. Illinois Commerce Comm'n*, 322 Ill. App. 3d 846, 849 (2d Dist. 2001) ("*ComEd*") (citing

[20] NS-PGL Ex. JH-3.7P, col. N, line 7 and NS-PGL Ex. JH-3.7N, col. N, line 6.

*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).

Illinois courts have reversed the Commission when it incorrectly has excluded a public utility's costs from recovery through rates. *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).

**Just and Reasonable**. The Commission, in a rate case, 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 to recover fully its costs of service is in the long-term interests of customers as well as the utility.

> For a utility to experience large cost recovery shortfalls is not in the long term interests of customers, and such a situation simply is not sustainable. Moreover, large cost recovery shortfalls deny a fair return to investors and therefore will increase the utility's costs of capital over time. Peoples Gas would not be seeking this rate relief unless it believed that it was necessary for the continued ability of this company to provide safe, adequate, and reliable service and to do so at the least long term cost.

Schott Dir., PGL Ex. JFS-1.0 Rev. at 4:74-80. *See also* Schott Reb., NS-PGL Ex. JFS-2.0 at 6:112-129; Schott Dir., NS Ex. JFS-1.0 Rev. at 3:60-66.

The Utilities recognize that the economic crisis is affecting their customers as well as the Utilities, but in light of that crisis the Utilities have taken extraordinary steps to reduce current and future costs. *E.g.*, Schott Dir., PGL Ex. JSF-1.0 Rev. at 4:81-86; Schott Dir., NS Ex. JFS 1.0

Rev. at 4:67-72. Those reductions are incorporated fully in the Utilities' final revised proposed revenue requirements. *See* Section III of this Initial Brief, *infra*.

The Commission should approve the Utilities' final revised proposed revenue requirements. Otherwise, they will continue to experience serious cost recovery shortfalls.

### 3. **Rider ICR**

It is ironic that one of the most contested items in this proceeding – Peoples Gas' proposed Rider ICR – proposes nothing controversial. The City of Chicago is a world class cultural and commercial city, which is a final four city in the International Olympic Committee's consideration for the Summer 2016 Olympics. However, approximately half of its natural gas distribution system is still comprised of aging cast iron and ductile iron mains providing low-pressure gas service that is a legacy from the time when Peoples Gas created gas from coal to supply fuel for lighting. Some of these pipes are over 100 years old, dating back to the 1860's. Rider ICR is a proposal that will help enable Peoples Gas to provide a new, modern gas distribution system for the City of Chicago sooner than otherwise possible by use of a rider, a cost-recovery mechanism that clearly is within the Commission's power to adopt.

Peoples Gas has proposed Rider ICR to allow the utility to recover annually a portion of the costs for replacing its aging cast iron and ductile iron mains, to help enable the company to accelerate its ongoing main replacement program. Peoples Gas introduced evidence as to the numerous benefits that accelerating its planned upgrades to its distribution system would provide to customers and the City of Chicago. That evidence is un-rebutted and unchallenged. Not one party has opposed the acceleration of Peoples Gas' main replacement program, or contested the evidence of its benefits such as construction cost savings, enhanced system safety, improved customer safety, the increased ability for customers to install higher-efficiency appliances,

significant reductions in greenhouse gas emissions and the creation of jobs. By accelerating its main replacement program, Peoples Gas would merely be expanding the scope of what it is already doing to make these benefits available to customers sooner.

Likewise, although opposed by a few parties because it is not "traditional,"[21] there is nothing new or controversial about allowing a utility to recover the costs for such a program via a rider mechanism. It is well-established that the Commission has the discretion under the Public Utilities Act, 220 ILCS Act 5, to authorize rider recovery. Indeed, in addressing this issue in the Utilities' last rate cases, after reviewing the history of Illinois case law on the matter, the Commission concluded: "Thus, the whole of the case law settles the question of our authority to adopt the rider mechanism in proper situations and under circumstances that are lawful and reasonable." *Peoples 2007* at 139-140. In recent years, the Commission has authorized riders for Illinois utilities in rate cases for revenue decoupling,[22] the recovery of the costs for an energy efficiency program.[23] and implementing and recovering the costs for Smart Grid technology and Advanced Metering Infrastructure ("AMI").[24] Moreover, the evidence shows that rider treatment for the costs of accelerating the replacement of aging infrastructure has become an accepted practice throughout the country. Peoples Gas' expert witness, Salvatore Marano, documented that similar cost recovery mechanisms have been approved by state utility commissions for the infrastructure replacement programs of at least twenty natural gas distribution companies as of December 2007. Marano Dir., PGL Ex. SDM-1.0 Rev. at 36:668 – 37:678.

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[21] Staff and the AG submitted testimony and recommendations in opposition to Rider ICR but not to the evidence as to the benefits of Peoples Gas' proposed accelerated main replacement program.

[22] Rider VBA authorized in *Peoples 2007* at 138-153.

[23] Rider EEP authorized in *Peoples 2007* at 183-184, and rider approved in *Nicor 2008* at 157-158.

[24] Rider SMP authorized in *In re Commonwealth Edison Company*, ICC Docket No. 07-0566, at 137-143 (Order, September 10, 2008).

In considering Peoples Gas' Rider ICR as proposed in its previous rate case, the Commission found that version of the rider to pose single-issue ratemaking concerns because it failed to account for and flow savings generated by the accelerated main replacement back to customers. *Peoples 2007* at 159-160. That has been addressed in the Rider ICR proposed here. Rider ICR as proposed in the present case provides a factor for flowing these savings back to customers, as well as procedures for auditing the costs and savings, reviewing Rider ICR charges in an annual reconciliation process, updating the savings factor every three years, and the ability for the Commission to adjust the savings factor more often if necessary. Nor would the Rider ICR proposed here circumscribe the Commission's statutory power to initiate a proceeding to review the reasonableness of Rider ICR, thereby removing the Commission's other legal concern regarding the rider as proposed in Peoples Gas' last rate case. *See id*. at 157-158.

Significantly, in Peoples Gas' last rate case, the Commission specifically listed the type of information it needed to approve an infrastructure modernization initiative such as Rider ICR. *Id*. at 162. Peoples Gas has followed the Commission's guidance, providing detailed evidence and analysis by a leading expert in the field of natural gas distribution infrastructure as to:

- a detailed description and cost analysis of the proposed system modernization;
- an identification, evaluation and justification of the technology involved;
- a detailed identification and description of the improved functionalities of the modernized system both for the company and for customers; and
- an analysis of the benefits of the system modernization in terms of reduced operating and maintenance costs, enhanced system safety, improved customer safety and reliability, reduced greenhouse gas emissions and increased options for energy efficient appliances, new products and services.

Furthermore, Peoples Gas witnesses provided an analysis of Rider ICR as a regulatory mechanism to recover the costs of modernizing the company's distribution system and flow reduced costs of that system back to customers.

Thus, Peoples Gas has provided the information that the Commission requested to evaluate a Rider ICR proposal, and that evidence shows only benefits to customers for accelerated system modernization. There has never been any question as to the need for Peoples Gas to eventually replace its aging infrastructure, and now there is no doubt that the costs of accelerating that replacement are greatly outweighed by the quantitative and qualitative benefits acceleration would provide. Rider ICR undoubtedly will help enable Peoples Gas to accelerate its main replacement program to create these benefits. Accordingly, the situation is proper and the circumstances are lawful and reasonable for the Commission to authorize Rider ICR.

On the other hand, contrary to Staff's recommendations, the evidence does not show any need for the Commission to engage in the micro-management of Peoples Gas' main replacement program by ordering a particular program of accelerated main replacement; the review, analysis and pre-approval of the company's management of such a plan; or the costs of additional outside consultants to monitor and analyze the company's program for the Commission. Staff performed no independent analysis of Peoples Gas' main system or replacement programs, but rather, relied upon its interpretation of the testimony of the company's expert witness to recommend that acceleration be ordered on the basis of "public safety." The evidence, however, plainly demonstrates that while there are many benefits to accelerating the main replacement program, including enhanced safety and improved risk management, there is "no immediate risk posed by [Peoples Gas'] current system and operating practices." Marano Dir., PGL Ex. SDM-1.0 Rev. at 29:510-511. Indeed, Staff witness Harold Stoller admits that there is no evidence in the record

that Peoples Gas' distribution system is not safe or not being operated safely at the present time. Stoller, Tr. at 899:6-13. Consequently, there is no need to order acceleration as would be required for such an order by Section 8-503 of the Public Utilities Act. 220 ILCS 5/8-503 (requiring a finding after hearing that improvements "are necessary" before the Commission is authorized to order they be made in a particular manner and within a specified time).

Similarly, no evidence was introduced by Staff to justify either the need or cost for the retention of an independent consultant to examine the utility's plan for accelerating its main replacement program or for the Commission to pre-approve it. In fact, Peoples Gas submitted evidence showing it is taking the proper steps to develop a detailed implementation plan to provide for the reasonable and prudent management and implementation of acceleration. Given no evidence of lack of diligence or prudence by Peoples Gas in preparing for an accelerated main replacement program or inability to implement and manage such a program, the recommendations of Staff are not justified. Moreover, if any indication arises in the future that additional auditing, monitoring, or oversight is needed, nothing would prevent the Commission from ordering such measures in the future if a showing to justify their need is made. Staff has failed to make such a showing at this time and thus, its recommendations should be denied.

### 4. Rate Design, Cost of Service, and Transportation Service

The Utilities' embedded cost of service studies ("ECOSSs") and resulting rate designs raised few issues that remain contested. Only the Utilities submitted ECOSSs. Neither Staff nor any party contested the adequacy and sufficiency of the ECOSSs. Notwithstanding the complexity of the studies, there is only one contested ECOSS issue, which concerns the proper classification of Account 904 ("Uncollectible Accounts"). The Utilities' rate design proposals hewed closely to their existing designs, including proposals that will improve the extent to which

the rates embody cost causation principles. Like the ECOSSs, there are very few contested issues. The Utilities' rate designs resulting from their ECOSSs, including the treatment of Account 904 costs, would produce just and reasonable rates.

The Utilities proposed no operational changes to their transportation programs, which are two distinct programs that offer all customers the opportunity to choose an alternative gas supplier. The Commission approved substantial program changes in the 2007 rate cases, and, after a transition period, the Utilities implemented many of those changes on August 1, 2008. Intervenors raised only a few issues concerning the programs, many of which were addressed by the Commission in the 2007 cases. There is insufficient support for operational changes to the programs in this proceeding, particularly given the recent implementation of changes.

## B. Nature of Operations

### 1. North Shore

North Shore is a local distribution company engaged in the business of transporting, purchasing, storing, distributing and selling natural gas at retail to approximately 158,000 residential, commercial, and industrial customers within fifty-four communities in Lake and Cook Counties, Illinois. Schott Dir., NS Ex. JFS-1.0 at 5:101-103; Doerk Dir., NS Ex. ED-1.0 at 3:49-51. North Shore employs approximately 170 people. Schott Dir., NS Ex. JFS-1.0 at 5:105. North Shore is a wholly owned subsidiary of Peoples Energy Corporation ("PEC"), which in turn is a wholly owned subsidiary of Integrys Energy Group, Inc. ("Integrys"). *Id.* at 5:106-107.

North Shore's distribution system consists of approximately 2,280 miles of gas distribution mains. Doerk Dir., NS Ex. ED-1.0 at 3:51-52. North Shore owns approximately 95 miles of gas transmission lines. *Id.* at 3:52-53. Its distribution system is most commonly operated at a pressure of 45 pounds per square inch ("PSI"), while the transmission system

operates at a pressure of 250 pounds PSI. *Id.* at 3:53-55. While North Shore does not own any storage fields, it does purchase storage services from Peoples Gas, pursuant to an agreement approved by the Commission. *Id.* at 3:55-60. North Shore also owns a liquid propane production facility used for peaking purposes. *Id.* at 3:60-61.

The physical configuration of North Shore's system is a dispersed/multiple city-gate, integrated transmission/distribution and multi pressure-based system. Doerk Dir., NS Ex. ED-1.0 at 3:63-64. It is designed to provide gas service to all customers entitled to be attached to the system, to deliver volumes of natural gas to all sales and transportation customers, and to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day. *Id.* at 4:66-69. A system sized only to accommodate average gas demands would not be able to meet system peak demands. *Id.* at 4:69-70.

**2. <u>Peoples Gas</u>**

Peoples Gas is a local distribution company engaged in the business of transporting, purchasing, storing, distributing, and selling natural gas at retail to approximately 850,000 residential, commercial, and industrial customers within the City of Chicago. Schott Dir., PGL Ex. JFS-1.0 at 6:115-117; Doerk Dir., PGL Ex. ED-1.0 at 4:66-67. This service territory covers an area of about 237 square miles and has a population of approximately three million people. Schott Dir., PGL Ex. JFS-1.0 at 6:117-118. Peoples Gas employs approximately 1,110 people, all within the City of Chicago. *Id.* at 6:119. Peoples Gas is a wholly owned subsidiary of PEC, which in turn is a wholly owned subsidiary of Integrys. *Id.* at 6:120-121.

Peoples Gas' distribution system consists of approximately 4,025 miles of gas distribution mains. Doerk Dir., PGL Ex. ED-1.0 at 4:67-68. It owns approximately 425 miles of gas transmission lines. *Id.* at 4:68-69. The distribution system is most commonly operated at a

pressure range of 0.25 to 25 pounds PSI, while the transmission system operates at pressures up to 300 pounds PSI or more. *Id.* at 4:69-71. Peoples Gas also owns a storage field, Manlove Field. *Id.* at 4:72.

The physical configuration of Peoples Gas' system is a dispersed/multiple city gate, integrated transmission/distribution and multi pressure-based system. Doerk Dir., PGL Ex. ED-1.0 at 4:76-77. It is designed to provide gas service to all customers entitled to be attached to the system, to deliver volumes of natural gas to all sales and transportation customers, and to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day. *Id.* at 4:79-82. A system sized only to accommodate average gas demands would not be able to meet system peak demands. *Id.* at 4:82-83.

## II. TEST YEAR (Uncontested)

The Utilities proposed calendar year 2010, the twelve months ending December 31, 2010, as their test year. Moy Dir., PGL Ex. SM-1.0 at 4:83-84; Moy Dir., NS Ex. SM-1.0 at 4:82-83. The 2010 test year data were based on the Utilities' forecasted 2010 revenues, expenses, and rate bases, subject to appropriate adjustments.[25] No party contested the proposed test year.

## III. REVENUE REQUIREMENT

The formula for determining a utility's costs of service -- its "revenue requirement" -- is well established. RR = OE + (ROR x RB). A utility's revenue requirement ("RR") equals: (1) its operating expenses ("OE") plus (2) a reasonable rate of return ("ROR") on its capital

[25] Moy Dir., PGL Ex. SM-1.0 at 5:98-104, 6:124-125; Gregor Dir., PGL Ex. CMG-1.0 Rev. at 5:103-105; Moy Dir., NS Ex. SM-1.0 at 5:97-103, 6:123-124; Gregor Dir., NS Ex. CMG-1.0 at 5:100-102.

investments ("RB") (the capital investments to which the rate of return is to be applied are referred to as its "rate base").[26] *E.g.*, *ComEd*, 322 Ill. App. 3d at 849.

### A. <u>North Shore</u>

North Shore's existing rates fall far short of allowing it to recover its costs of service, as discussed in Section I(A) of this Initial Brief. North Shore's comprehensive direct case supported in detail a base rate revenue requirement[27] of $87,279,000, which meant that its cost recovery shortfall (its revenue deficiency) under existing rates in the 2010 test year, which begins less than four months from now, would be $21,986,000. Moy Dir., NS Ex. SM-1.0 at 2:33-43; NS Ex. SM-1.1 at Sched. C-1, line 1. The drivers of the cost under-recovery are discussed in Section I(A). The extensive evidence supporting North Shore's rate base, operating expenses, and rate of return is discussed in Sections IV, V, and VI, *infra*, respectively.

North Shore's detailed rebuttal testimony supported a lower revenue requirement of $85,314,000, reducing the cost recovery shortfall to $20,021,000. Moy Reb., NS-PGL Ex. SM-2.0 at 2:40-44; NS-PGL Ex. SM-2.1N at Sched. C-1, line 1. The reductions reflected that North Shore, in its rebuttal, agreed with or accepted in order to narrow the issues, in whole or in part, numerous Staff- and intervenor-proposed adjustments, and updated certain items, including the items affected by the cost control measures adopted in light of the economic

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[26] The "return of", as opposed to the "return on", capital investments is to be recovered through the depreciation expenses component of operating expenses.

[27] Consistent with the revenue requirement formula discussed above, each utility's base rate revenue requirement is the sum of (1) its base rate operating expenses plus (2) its operating income requirement. *E.g.*, NS Ex. SM-1.1 at Sched. C-1, lines 1, 22, 23; PGL Ex. SM-1.1 at Sched. C-1, lines 1,22, 23. The operating income requirement number is simply the product of multiplying the utility's rate base by its cost of capital. *E.g.*, NS Ex. SM-1.1 at Sched. A-2, lines 1-7, and Sched. C-1, line 23; PGL Ex. SM-1.1 at Sched. A-2, lines 1-7, and Sched. C-1, line 23.

The revenue requirement figures for North Shore and Peoples Gas discussed in this Initial Brief do not include the Cost of Gas, the Environmental Activities costs, and the Enhanced Energy Efficiency Program costs recovered through Rider 2, Rider 11, and Rider EEP, respectively. *E.g.*, Moy Dir., NS Ex. SM-1.0 at 2:33-37; Moy Dir., PGL Ex. SM-1.0 at 2:33-37.

downturn, a decreased forecasted price of natural gas for 2010, increased pension expenses, and a reduced rate of return. Moy 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; Schott Reb., NS-PGL Ex. JFS-2.0 at 6:130 - 7:141; NS-PGL Ex. JFS-2.1;[28] Johnson Reb., NS-PGL Ex. BAJ-2.0 2Rev. at 22:467-469.

Finally, North Shore's detailed surrebuttal testimony supported a further-reduced revenue requirement of $83,305,000, meaning its test year cost recovery shortfall under current rates would be $18,105,000. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 3:50-54; NS-PGL Ex. SM-3.1N at Sched. C-1, line 3. The additional reductions reflected that North Shore, in its surrebuttal, again agreed with or accepted, in whole or in part, numerous Staff- and intervenor-proposed adjustments and updated certain items. [29]

The Commission should approve North Shore's final revised revenue requirement. North Shore is entitled to recover these proven costs. The remaining contested adjustments proposed by Staff and intervenors are not correct, as discussed in Sections IV, V, and VI, *infra*.

### B. <u>Peoples Gas</u>

Peoples Gas' existing rates also fall far short of allowing it to recover its costs of service, as discussed in Section I(A) of this Initial Brief. Peoples Gas' comprehensive direct case supported in detail a base rate revenue requirement of $624,054,000, which meant that its cost recovery shortfall under existing rates as of the 2010 test year, now less than four months away, would be $161,920,000. Moy Dir., PGL Ex. SM-1.0 at 2:33-43; PGL Ex. SM-1.1 at Sched. C-1,

[28] Mr. Schott's rebuttal and surrebuttal testimony each presented an attached list of adjustments proposed by Staff and intervenors with which the Utilities agreed, or accepted in order to narrow the issues, in whole or in part.

[29] Moy Reb., 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; Schott Sur., NS-PGL Ex. JFS-3.0 at 6:121-125; NS-PGL Ex. JFS-3.1. Please note: North Shore's and Peoples Gas' surrebuttal figures incorporate the proposal they made, in an attempt to narrow the issues, on the subject of injuries and damages expenses and reserves, that is discussed in Section V(C)(7)(a) of this Initial Brief, *infra*.

line 1. The causes of the cost under-recovery are discussed in the Section I(A) of this Initial Brief. The extensive evidence supporting Peoples Gas' rate base, operating expenses, and rate of return is discussed in Sections IV, V, and VI, *infra*, respectively.

Peoples Gas' detailed rebuttal testimony supported a lower revenue requirement of $584,499,000, meaning its test year cost recovery shortfall under current rates would be decreased to $122,365,000. Moy Reb., NS-PGL Ex. SM-2.0 at 2:40-44; NS-PGL Ex. Ex. SM-2.1P at Sched. C-1, line 1. The decreases reflected that Peoples Gas, in its rebuttal, agreed with or accepted in order to narrow the issues, in whole or in part, numerous Staff- and intervenor-proposed adjustments, and updated certain items, including the items affected by cost control measures adopted in light of the economic downturn, a decreased forecasted price of natural gas for 2010, and a reduced rate of return.[30]

Finally, Peoples Gas' detailed surrebuttal testimony supported a further-reduced revenue requirement of $574,038,000, meaning its test year cost recovery shortfall under current rates would be $113,178,000. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 3:50-54; NS-PGL Ex. SM-3.1P at Sched. C-1, line 3. The additional reductions reflected that Peoples Gas, in its surrebuttal, again agreed with or accepted, in whole or in part, numerous Staff- and intervenor-proposed adjustments and updated certain items.[31]

The Commission should approve Peoples Gas' final revised revenue requirement. Peoples Gas is entitled to recover these proven costs through its rates. Staff's and intervenors' contested proposed adjustments are erroneous, as discussed in Sections IV, V, and VI, *infra*.

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[30] Moy Reb., NS-PGL Ex. SM-2.0 at 2:31-33, 2:37-39, 3:67 - 5:111; 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; Johnson Reb., NS-PGL Ex. BAJ-2.0 2Rev. at 22:467-469.

[31] Moy Reb., NS-PGL Ex. SM-3.0 Rev. at 2:35-42, 3:46-49, 4:75-84; 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.

## IV. RATE BASE

### A. Overview/Summary/Totals

#### 1. North Shore

North Shore's surrebuttal presented a rate base of $179,927,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part, certain updates, and the correction of certain prior calculation errors. Hengtgen Sur., NS-PGL Ex. JH-3.0 at 2:34-36, 4:64 - 6:121, *et seq.*; NS-PGL Ex. JH-3.1N (Sched. B-1); NS-PGL Ex. JH-3.2N (Sched. B-2); Schott Sur., NS-PGL Ex. JFS-3.0 at 6:121-125; NS-PGL Ex. JFS-3.1.

North Shore's rate base is supported by extensive, detailed evidence, including the testimony of John Hengtgen (overall rate base and the underlying calculations and supporting various components of rate base);[32] Edward Doerk (key components of Gross Utility Plant);[33] Christine Gregor (the test year forecast, including the Capital Budget);[34] John Spanos (the depreciation study);[35] James Hoover (capitalized incentive compensation costs);[36] and Christine Phillips (updating the pension and OPEB liability figures).[37]

The Commission should approve North Shore's final revised rate base. North Shore is entitled to recover these proven costs through its rates.

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[32] Hengtgen Dir., NS Ex. JH-1.0; NS Ex. JH-1.1; Hengtgen Reb., NS-PGL. Ex. JH-2.0; NS-PGL Exs. JH-2.1N, JH-2.2N, JH-2.3N, JH-2.4N, JH-2.5N, JH-2.6N, JH-2.7N; Hengtgen Sur., NS-PGL Ex. JH-3.0; NS-PGL Exs. JH-3.1N, JH-3.2N, JH-3.4N, JH-3.5N, JH-3.6N, JH-3.7N, JH-3.8, JH-3.10N.

[33] Doerk Dir., NS Ex. ED-1.0; NS Ex. ED-1.1; Doerk Reb., NS-PGL Ex. ED-2.0; Doerk Sur., NS-PGL Ex. ED-3.0.

[34] Gregor Dir., NS Ex. CMG-1.0; NS Ex. CMG-1.1; Gregor Reb., NS-PGL Ex. CMG-2.0; NS-PGL Exs. CMG-2.1N, CMG-2.2N, CMG-2.3N, CMG-2.4N, CMG-2.5N; Gregor Sur., NS-PGL Ex. CMG-3.0; NS-PGL Exs. CMG-3.1N, CMG-3.2N.

[35] Spanos Dir., NS Ex. JJS-1.0; NS Ex. JJS-1.1.

[36] Hoover Reb., NS-PGL Ex. JCH-1.0; Hoover Sur., NS-PGL Ex. JCH-2.0.

[37] Phillips Reb., NS-PGL Ex. CMP-1.0; NS-PGL Exs. CMP-1.1, CMP-1.2, CMP-1.3.

### 2. **Peoples Gas**

Peoples Gas's surrebuttal presented a rate base of $1,300,750,000, reflecting adjustments proposed by Staff and intervenors that the utility accepted in whole or in part, certain updates, and the correction of certain prior calculation errors. Hengtgen Sur., NS-PGL Ex. JH-3.0 at 2:34-36, 4:64 - 6:121, *et seq.*; NS-PGL Ex. JH-3.1P (Sched. B-1); NS-PGL Ex. JH-3.2P (Sched. B-2); Schott Sur., NS-PGL Ex. JFS-3.0 at 6:121-125; NS-PGL Ex. JFS-3.1.

Peoples Gas' rate base is supported by extensive, detailed evidence, including the testimony of John Hengtgen (overall rate base and the underlying calculations and supporting various components of rate base);[38] Edward Doerk (key components of Gross Utility Plant);[39] Christine Gregor (the test year forecast, including the Capital Budget);[40] John Spanos (the depreciation study);[41] James Hoover (capitalized incentive compensation costs);[42] Christine Phillips (updating the pension asset and OPEB liability figures);[43] Alan Felsenthal (the inclusion of the pension asset in rate base);[44] and Thomas Puracchio (certain capital projects)[45].

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[38] Hengtgen Dir., PGL Ex. JH-1.0; PGL Ex. JH-1.1; Hengtgen Reb., NS-PGL. Ex. JH-2.0; NS-PGL Exs. JH-2.1P, JH-2.2P, JH-2.3P, JH-2.4P, JH-2.5P, JH-2.6P, JH-2.7P; Hengtgen Sur., NS-PGL Ex. JH-3.0; NS-PGL Exs. JH-3.1P, JH-3.2P, JH-3.3P, JH-3.4P, JH-3.5P, JH-3.6P, JH-3.7P, JH-3.8, JH-3.9, JH-3.10P.

[39] Doerk Dir., PGL Ex. ED-1.0 Rev.; PGL Ex. ED-1.1; Doerk Reb., NS-PGL Ex. ED-2.0; Doerk Sur., NS-PGL Ex. ED-3.0.

[40] Gregor Dir., PGL Ex. CMG-1.0; PGL Ex. CMG-1.1; Gregor Reb., NS-PGL Ex. CMG-2.0; NS-PGL Exs. CMG-2.1P, CMG-2.2P, CMG-2.3P, CMG-2.4P, CMG-2.6P; Gregor Sur., NS-PGL Ex. CMG-3.0; NS-PGL Exs. CMG-3.1P, CMG-3.2P.

[41] Spanos Dir., PGL Ex. JJS-1.0; PGL Ex. JJS-1.1.

[42] Hoover Reb., NS-PGL Ex. JCH-1.0; Hoover Sur., NS-PGL Ex. JCH-2.0.

[43] Phillips Reb., NS-PGL Ex. CMP-1.0; NS-PGL Exs. CMP-1.1, CMP-1.2, CMP-1.3.

[44] Felsenthal Reb., NS-PGL Ex. AF-1.0; Felsenthal Sur., NS-PGL Ex. AF-2.0.

[45] Puracchio Reb., NS-PGL Ex. TLP-2.0; Puracchio Sur., NS-PGL Ex. TLP-3.0; NS-PGL Exs. TLP-3.1, TLP-3.2, TLP-3.3.

The Commission should approve Peoples Gas' final revised rate base. Peoples Gas is entitled to recover these proven costs through its rates.

## B. Uncontested Issues

### 1. Natural Gas Prices for Purposes of Cushion Gas (PGL), Gas in Storage, and Cash Working Capital

The Utilities, Staff, AG, and CUB agree that the natural gas prices for the purposes of cushion gas (Peoples Gas only), gas in storage, and cash working capital should be updated based upon data in the Utilities' August Gas Charge filings. Gregor Sur., NS-PGL Ex. CMG-3.0 at 2:35-3:65; Hengtgen Sur., NS-PGL Ex. 3.0 at 4:67-70, 5:89-92, 6:115-117; Effron Reb., AG-CUB Ex. 4.0 at 4:45-60; Seagle Reb., Staff Ex. 27.0 at 13:246-17:322; Rearden, Tr. at 914:19 - 915:7.

### 2. Plant

#### a. Original Cost Determinations as to Plant Balances as of 12/31/2007

Utility witness Mr. Hengtgen's proposal that the Commission's final Order include an original cost determination as to each utility is uncontested. Mr. Hengtgen proposed that the Order make such determinations, pursuant to 83 Ill. Adm. Code Part 510 and its Appendix A, regarding Peoples Gas' and North Shore's Gross Utility Plant balances as of December 31, 2007. Hengtgen Dir., PGL Ex. JH-1.0 at 17:378-18:392; Hengtgen Dir., NS Ex. JH-1.0 at 14:298-312.

Staff witness Mr. Bridal agreed that such a determination be included in the Commission's final Order. He recommended that the Order state in part:

> It is further ordered that the $2,525,147,000 original cost of plant for Peoples Gas at December 31, 2007, as reflected on the Company's Schedule B-5, Page 1 of 2, Line 14, Column F; and the $398,983,000 original cost of plant for North Shore at December 31, 2007, as reflected on the Company's Schedule B-5, Page 1 of 2, Line 12, Column F, are unconditionally approved as the original costs of plant.

Bridal Dir., Staff Ex. 5.0 at 8:165 – 9:184. The Utilities agreed. Hengtgen Reb., NS-PGL Ex. JH-2.0 at 17:371 – 18:383. No witness disagreed. Mr. Bridal's proposed language should be included in the Findings and Ordering section of the final Order.

**b. <u>Capitalized Union Wages</u>**

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

**c. <u>Capitalized Civic, Political, and Related Activities</u>**

Please see Section V(B)(7)(f) of this Initial Brief, *infra*.

**d. <u>Net Dismantling</u>**

North Shore and Peoples Gas proposed to change the accounting for the net dismantling (*i.e.*, the cost of removal of an asset, net of salvage) portions of their Depreciation Reserves from a cash basis to an accrual basis, effective January 1, 2010. Gregor Dir., NS Ex. CMG-1.0 at 20:422-443:, Gregor Dir., PGL Ex. CMG-1.0 Rev. at 21:451 - 22:472. No testimony opposed that proposal.[46] North Shore and Peoples Gas request that the final Order contain language expressly approving the proposal, so that it will be clear that it has been approved.

**e. <u>Gathering System Pigging Project (PGL)</u>**

One of the many Peoples Gas projects expected to enter service before the end of the test year is the Gathering System Pigging Project, in which approximately $500,000 will be spent in 2009. NS-PGL Cross Ex. Effron 29. Staff witness Mr. Seagle initially objected to the inclusion of this project in rate base, but after receiving further information, Mr. Seagle agreed that the project was properly included in Peoples Gas' rate base. Seagle, Tr. at 911:2-5.

[46] At one point, there was a disagreement between Staff and the Utilities regarding an aspect of the net dismantling computations, but, after the Utilities presented further testimony, Staff accepted the Utilities' approach. Moy Reb., NS-PGL Ex. SM-2.0 at 5:114 - 6:134; Everson Reb., Staff Ex. 18.0 at 3:50-58.

#### f. Cushion Gas – Recoverable (PGL)

There is no dispute as to the amount of recoverable cushion gas to include in Peoples Gas' rate base. As discussed in Section IV(B)(1), *supra*, the parties now also agree to its price. Thus, Peoples Gas' recoverable cushion gas additions should be valued at $349,000 and $381,000 for 2009 and 2010, respectively. *See* NS-PGL Ex. JH-3.3P, p. 1, line 8.

#### g. Cushion Gas – Non-Recoverable (PGL)

Similarly, there is no dispute as to the amount of unrecoverable cushion gas. Thus, Peoples Gas' non-recoverable cushion gas additions should be valued at $6,628,000 and $7,236,000 for 2009 and 2010, respectively. *See* NS-PGL Ex. JH-3.3P, p. 1, line 3.

#### h. Capitalized Savings Plan Costs

AG-CUB-City witness Mr. Effron initially proposed to capitalize a portion of the Savings and Investment Plan cost based on the Utilities' responses to data requests AG 3.21 and AG 3.67. AG-CUB-City Ex. 1.0 at 23:495-504. Later, after receiving further information, Mr. Effron withdrew his adjustment as no longer necessary. AG-CUB Ex. 4.0 at 11:189-194.

### 3. Accumulated Reserve for Depreciation and Amortization

#### a. Inventory Reclassification

Staff witness Ms. Hathhorn proposed adjustments to the Depreciation Reserve, Gas in Storage (as to Peoples Gas), and Accumulated Deferred Income Taxes related to inventory reclassification. The Utilities accepted those adjustments. Hengtgen Reb., NS-PGL Ex. JH-2.0 at 4:70; NS-PGL Ex. JH-2.2N at Sched. B-2, col. [D]; NS-PGL Ex. JH-2.2P at Sched. B-2, col. [C]. *See* Section V(B)(8)(a), *infra*, for the operating expenses side of this subject.

### 4. Materials and Supplies Correction

The Utilities corrected an error in the original level of materials and supplies. Hengtgen Sur., NS-PGL Ex. JH-3.0 at 4:76 - 5:84. The corrected levels are shown on line 5 of the Revised Schedule B-1 for each of the Utilities, NS-PGL Exs. 3.1N and 3.1P.

### 5. Gas in Storage

The Utilities corrected an error in the original gas in Storage calculations, and used the final updated figures for the price of natural gas. Hengtgen Sur., NS-PGL Ex. JH-3.0 at 5:99 - 6:109. The uncontested amounts for gas in storage are shown on line 6 of the Revised Schedule B-1 for each of the Utilities, in NS-PGL Exs. 3.1N and 3.1P.

### 6. Methodology to Account for Amortization of Remaining Pre-Merger Unamortized Costs

In order to refine the methodology for amortizing the remaining pre-merger unamortized costs, the Utilities proposed to separately identify the remaining pre-merger net regulatory assets for pension and other welfare benefit plans and amortize those costs using a straight-line amortization based on the average remaining service lives of the underlying benefit plans, effective January 1, 2010. Gregor Dir., PGL Ex. CMG-1.0 Rev. at 20:438-443; Gregor Dir., NS Ex. CMG-1.0 at 19:409-414. This change (1) will eliminate the need for the actuary to prepare a separate accounting valuation; and (2) will reflect an additional decrease to pension costs and an additional increase to welfare costs in the test year. Gregor Dir., PGL Ex. CMG-1.0 Rev. at 20:443-446; NS Ex. CMG-1.0 at 19:414-417. No witness objected to this change. North Shore and Peoples Gas request that the final Order contain language expressly approving the proposal, so that it will be clear that it has been approved.

## C. Plant

### 1. Forecasted Plant Additions

From the time of the Utilities' initial filing in February, the Utilities' forecasted plant additions have changed some in response to the economy. In their direct testimony, the Utilities announced that they were adopting cost control measures that would be reflected in their rebuttal testimony, as noted earlier in this Initial Brief. In response to data requests before their rebuttal testimony, the Utilities stated in March the reduced level of plant additions. *See* Everson Dir., Staff Ex. 4.0 at 4:61-70. However, as the Utilities refined their budgets, the forecast plant additions changed again, increasing slightly from those reduced levels. In response to subsequent data requests, the Utilities in July set out the revised forecast. NS-PGL Cross Exs. Effron 26 and 28. The Utilities also explained why the forecasts had changed and the details of the changes, both in testimony and in response to data requests. *E.g.*, NS-PGL Cross Exs. Effron 27 and 29. The forecasts have not changed since that time.

It is appropriate to rely on the latest, most accurate forecast of plant additions, and that is what the Utilities have done. 2009 is well under way, and planning for 2010 is further along than earlier in the year. The current forecast reflects additional high priority public improvements and system improvements that will be completed. Doerk Sur., NS-PGL Ex. ED-3.0 at 3:52-55. The Utilities' latest forecast plant additions should therefore be used. *Id*. at 3:55-57.

Staff has reviewed that evidence and data request responses and agrees with the Utilities.

> I reviewed the rebuttal testimonies of PGL-NS witnesses Hengtgen and Doerk, and reviewed the explanations and the details regarding the changes Peoples Gas and North Shore provided in response to my data requests, MHE 15.01 and 15.02. Based on the Companies' explanations and details supporting the changes in the specific projects, I am not contesting the Companies' rebuttal levels of forecasted plant additions….

Everson Reb., Staff Ex. 18.0 at 3:41-46.

Mr. Effron's continued use of the interim forecast numbers from March is not reasonable, not supported by any evidence, and would deny the Utilities recovery for projects that are actually in their approved budgets and will be serving customers. His cross-examination showed that he was presented with detailed, updated supporting information and that he has no basis for advocating use of older data instead of the latest information. Effron, Tr. at 786:12 – 789:2; NS-PGL Cross Exs. Effron 26, 27, 28, and 29.

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

Peoples Gas' only gas storage facility is Manlove Field. Gas is injected underground into the former water-bearing aquifer, so that it can be extracted when needed to serve customers. An integral component of the field is a network of pipes that are used when extracting gas from the field. This gathering system at Manlove has been used to serve customers for many years.

Peoples Gas has identified reasons to modernize the system and replace aging and corroding pipes. One important maintenance tool is "pigging," that is, to send a large object, known as a pig, through the pipes, which serves to clean them and de-water them. Puracchio Reb., NS-PGL Ex. TLP-2.0 at 2:28-38. Much of the existing gathering system is not designed and configured to be pigged. One purpose of the Gathering System Replacement Project is to have modern, pig-compatible pipes. Puracchio Dir., PGL Ex. TLP-1.0 at 9:181-186. Second, the existing pipes have been developing corrosion, which has reliability implications. Puracchio Sur., NS-PGL Ex. TLP-3.0 at 2:35 - 3:47.

Overall, this is a multi-year project that will cost tens of millions of dollars. Puracchio Dir., PGL Ex. TLP-1.0 at 8:164-168; Doerk Dir., PGL Ex. ED-1.1 at line 3. The question, therefore, is how much of the project to include in rate base using a 2010 test year, because the project will not be complete in 2010. $1,500,000 is being spent in 2009 for the engineering

study that will help chart which pipes will be replaced in which years. Puracchio Reb., NS-PGL Ex. TLP-2.0 at 6:113-118; Puracchio Sur., NS-PGL Ex. TLP-3.0 at 4:69-74. Staff does not contest that investment (Staff calls the 2009 expenditures "Phase 1"). Peoples Gas has forecasted $5.7 million to be spent in 2010 (Puracchio Reb., NS-PGL Ex. TLP-2.0 at 6:120-133; NS-PGL Cross Ex. Effron 29), but Staff has proposed to disallow that investment from rate base. Seagle Reb., Staff Ex. 27.0 at 4:59-63.

In testimony, Staff witness Mr. Seagle presented two arguments, neither of which warrants the disallowance. First, Mr. Seagle suggested that Peoples Gas had not shown that the replacement pipes would be used and useful in serving customers. Seagle Dir., Staff Ex. 13.0 at 7:134 - 8:136. The evidence shows otherwise. The replacement pipes will have the same function as the pipes currently in use, and such pipes are critical to the operation of the storage field. Mr. Seagle admitted this on cross examination. Tr. at 911-912.

Second, Mr. Seagle said that, as of the time of his rebuttal testimony, the engineering study was not far enough along to say whether the project would really proceed. Seagle Reb., Staff Ex. 27.0 at 12:227 - 13:245. In response, Peoples Gas presented testimony from Mr. Puracchio and from the engineering consultant that is performing the study. Although the overall scope of the project – for example, whether the project will last ten years or only eight – is not yet known, based on the analyses that have already been performed, it is clear that the forecasted 2010 work will need to proceed or be accelerated. Puracchio Sur., NS-PGL Ex. TLP-3.0 at 4:81 – 5:93; Marano Sur., NS-PGL Ex. SDM-3.0 at 15:327 – 16:346.

Accordingly, Staff's proposed disallowance of $5.7 million should be rejected.

### 3. <u>Capitalized Incentive Compensation</u>

Please see Section V(C)(1) of this Initial Brief.

#### 4. Capitalized Non-Union Base Wages

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

### D. Reserve for Accumulated Depreciation and Amortization (Uncontested Except for Derivative Adjustments from Contested Adjustments)

North Shore and Peoples Gas proposed to change the accounting for the net dismantling, which proposal is uncontested and is discussed in Section IV(B)(2)(d), *supra*.

All of Staff's and intervenors' proposed adjustments to the Reserve are derivative of their proposed adjustments to other items, as is shown in their Schedules. Hathhorn Reb., Staff Ex. 15.0 at Sched. 15.4 P, line 13, and Sched. 15.4 N, line 13; AG-CUB Ex. 4.1 at Sched. B-3 Corr.; AG-CUB Ex. 4.2 at Sched. B-3 Corr.

Accordingly, apart from the net dismantling point, the Commission's final Order, as to the Reserve, need only reflect derivative calculations, if any, depending on its ruling on the relevant contested adjustments. There is no dispute as to how those calculations are performed.

### E. Cash Working Capital

Cash working capital is the amount of funds required to finance the day-to-day operations of a utility. The cash working capital requirement is included in each of the Utilities' rate bases for ratemaking purposes. Hengtgen Dir., PGL Ex. JH-1.0 at 19:413-419; Hengtgen Dir., NS Ex. JH-1.0 at 15:333 – 16:339. To determine the cash working capital requirement, a lead-lag study analyzes the differences between the revenue lags and the expense leads of a utility. Three broad categories of leads and lags are considered: (1) lag times associated with the collection of revenues owed to the utility; (2) lead times associated with the payment of what are commonly called "pass-through" taxes and "energy assistance charges," and (3) lead times associated with the payments for goods and services received by the utility. Hengtgen Dir., PGL Ex. JH-1.0 at

20:425-431. The Utilities performed a lead-lag study closely conforming to the methodology adopted by the Commission in the 2007 rate cases. *Id.* at 20:439-446.

### 1. **Pass-Through Taxes**

The only contested aspect of the Utilities' lead-lag cash working capital study relates to pass-through taxes. The pass-through taxes and energy assistance charges are not recorded as revenue or expense on the income statement, but their collection and payment cause a timing difference in the cash flow that needs to be accounted for. Hengtgen Dir., PGL Ex. JH-1.0 at 23:504 – 24:510; Hengtgen Dir., NS Ex. JH-1.0 at 20:424-430. Again, the Utilities conducted their analysis as approved by the Commission in their last rate cases.

Staff, however, proposes to change the methodology, causing a large and unsubstantiated disallowance of a portion of the Utilities' cash working capital. Staff's proposal to arbitrarily assign a revenue lag of zero days to pass-through taxes and energy assistance charges is improper and is not supported by the evidence in these cases.

Staff's witness here, Mr. Ostrander, first argued in his direct testimony that because cash received from customers for pass-through taxes is not a payment for utility service, there should be no revenue lag. Ostrander Dir., Staff Ex. 3.0 at 7:131-133. That incorrect assertion was refuted by Mr. Hengtgen in his rebuttal, where he described the types of pass-through taxes and energy assistance charges and that the majority of the pass-through taxes and energy assistance charges were taxes or charges imposed by law on the Utilities and not the customers and were either collected through a separate charge prescribed by law or described within the statute as a charge for utility service. Hengtgen Reb., NS-PGL Ex. JH-2.0 at 12:244-263.

In his rebuttal testimony, Mr. Ostrander argued that pass-through taxes are not technically "revenues" so they cannot have a revenue lag. Ostrander Reb., Staff Ex. 17.0 at 6:101-110. He

ignores the fact that the pass-through taxes are not recorded as expense either. Consistent thinking would require that since they are not recorded as expense, they cannot have an expense lead either. The Utilities, in its direct testimony (Hengtgen Dir., NS Ex. JH-1.0 at 20:427-430; PGL Ex. JH-1.0 at 24:507-510), in rebuttal (Hengtgen Reb., NS-PGL Ex. JH-2.0 at 13:274-277) and again in its surrebuttal testimony (Hengtgen Sur., NS-PGL Ex. JH-3.0 at 8:149-151) have stated that the pass-through taxes are not recorded as revenue or expense but they do create timing issues in the collection and payment of the taxes. This is because the Utilities bill customers for the pass-through taxes in their normal billing process, and the customers do not pay the bills immediately to the Utilities when they receive their bills. The payment by the customers (or collections by the Utilities) occurs over several months after bills are issued. This "lag" in collection is the basis for the Utilities' calculation and use of lag days in its lead lag study. There is a corresponding expense (payment) lead because the Utilities do not remit the taxes to the taxing authorities on the same day they issue the bills to the customers. The due dates of the taxes are based on statutory due dates or various agreements with the taxing authorities. This payment "lead" is the basis for the utilities calculation of or use of lead days in its lead lag study.

Although Mr. Ostrander conceded that the Utilities had proposed a methodology that matched what the Commission approved in the Utilities' last rate case (Tr. at 752:13 – 753:3), he pointed out that zero revenue lag days were used in Nicor Gas' last rate case, *Nicor 2008*. The Utilities need not use the same method, because the facts are different. Nicor Gas reportedly collects pass-through taxes, holds them for a time, and then remits the money to various municipalities. Hengtgen Sur., NS-PGL Ex. JH-3.0 at 8:160 – 9:172. That would indicate that Nicor Gas bases its payments on actual cash collections from customers, which is now different

from the Utilities. Peoples Gas entered into an agreement with the City of Chicago, dated December 21, 2005, under which it pays, at a specific time, an estimate of the pass-through taxes owed to the City. Prior to this agreement, Peoples Gas paid its taxes based on actual cash receipts from customers. Hengtgen Sur., NS-PGL Ex. JH-3.9. North Shore and Peoples Gas use this same process for all pass-through taxes, whether covered by the City agreement or not. Hengtgen Reb., NS-PGL Ex. 2.0 at 14:309-311. There is a significant difference in methodology between companies. Nicor Gas uses actual cash receipts so it knows it has collected the taxes and holds the money for a period of time before payment. The Utilities make payments based on estimates regardless of whether or not the amounts are actually collected from customers. Hengtgen Reb., NS-PGL Ex. 2.0 at 14:306-309. As a result, the Utilities are uncertain if they have actually received the taxes before or after they have been paid.

Because of the Utilities' method of remitting pass-through taxes based on estimates and not knowing if the taxes have actually been collected, the Utilities calculations of pass-through taxes show an overall cash working capital close to zero, reflecting the lags and leads nearly cancelling each other out. Mr. Hengtgen's lead-lag study shows that for the tax payments to the City of Chicago of $171 million, the net cash working capital amount is a negative $40,000. Hengtgen Sur., NS-PGL Ex. JH-3.0 at 10:212 – 11:215.

Mr. Ostrander's use of the methodology ordered by the Commission in the Nicor Gas case is not appropriate here. His proposal uses a large expense lead, $23,661,000 for the City of Chicago alone, and zero revenue lag. Hengtgen Sur., NS-PGL Ex. JH-3.7P. Mr. Ostrander's conclusion would suggest a massively negative cash working capital figure. Ostrander, Tr. at 749:10 – 750:12. However, as he admitted, this is saying that, in effect, the Utilities are holding customers' money for 50.3 days (Peoples Gas) and 74.82 days (North Shore). Ostrander, Tr. at

750:21 – 752:7. There is no support in the record for this conclusion or result. While that might have been appropriate in Nicor Gas' situation, it does not reflect the Utilities' facts here.

#### 2. All Other (Uncontested)

All other cash working capital components are uncontested. The figures shown in the Revised Schedule B-8's in NS-PGL Exs. JH-3.6N and JH-3.6P, therefore, should be approved.

### F. Accumulated Deferred Income Taxes (Uncontested Except for Derivative Adjustments from Contested Adjustments)

Schedule B-9 shows the projected balances of Accumulated Deferred Income Taxes at December 31, 2009 and December 31, 2010, and the average amount for the test year. Hengtgen Dir., PGL Ex. JH-1.0 at 15:337 – 16:343; Hengtgen Dir., NS Ex. JH-1.0 at 12:258-264. Other than derivative adjustments from contested adjustments, these figures were not disputed by any party. The Utilities' final resulting amounts are shown on Revised Schedule B-1, line 10, columns D and F, in NS-PGL Exs. JH-3.1N and JH-3.1P.

### G. Reserve for Injuries and Damages

Please see Section V(C)(7)(a) of this Initial Brief, *infra*.

### H. Pension Asset (PGL) / Pension Liability (NS) And OPEB Liabilities

Staff and AG-CUB propose that Peoples Gas' pension asset be excluded from rate base on the theory that it was established by customer-supplied funds. Staff's argument is based on faulty assumptions regarding pension accounting principles and is not supported by the evidence. Additionally, despite arguing that the pension asset should be excluded from rate base, Staff argues that North Shore's pension liability should be included in rate base, although AG-CUB agrees with the Utilities that if the Peoples Gas pension asset is excluded then so should the North Shore pension liability. Staff and the AG-CUB join in arguing that the Utilities' OPEB

liabilities should be included in rate base. The Commission should reject such inconsistent treatment. Because the pension asset, the pension liability, and the OPEB liabilities are all related in nature, they should be treated consistently.

A utility's accrued pension liability generally results from pension expense calculated based on Financial Accounting Standard ("FAS") 87 being greater than pension contributions. Felsenthal Reb., NS-PGL Ex. AF-1.0 at 20:439-21:443. A pension asset, however, is created in two ways: (1) contributions to the pension fund; and (2) negative pension expense. Pension plan contributions are based on management decisions with various legal considerations contained in the Employee Retirement Income Security Act of 1972 ("ERISA") and the Internal Revenue Code ("IRC"). Felsenthal Reb., NS-PGL Ex. AF-1.0 at 6:114-121. 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. *Id.* However, pension expense, which is based on FAS 87, represents the annual pension cost that is actuarially determined in a manner that charges 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.

The other way to create a pension asset is for the annual pension cost computed under FAS 87 to be a negative expense – meaning that the expected return on plan assets exceeds other components of pension cost. *Id.* at 9:177-183. 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. *Id.* at 9:189-194.

The evidence clearly demonstrates that for the eight year period, beginning with 1996 (the year after Peoples Gas' second to last rate case, ICC Docket No. 95-0032, through and including 2003), there was aggregate negative pension expense (credits) each year totaling $174.3 million. Felsenthal Sur., NS-PGL Ex. AF-2.0 at 5:94-96. Staff's witness noted that, for the subsequent six year period, 2004 to 2009, there is aggregate pension expense of $18.4 million. Pearce Reb., Staff Ex. 16.0 at 9:217-225. However, she did not address the negative pension expense in the prior eight years, and it certainly does not change the numbers for the prior eight years. Further, 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 expense, the prepaid pension asset also represents amounts that have been contributed by Peoples Gas to the pension fund that <u>have not been recovered</u>, or that have been treated as a negative pension expense. *Id.* at 10:204-207.

Customers benefit in two ways in the years that there was negative pension expense: (1) reduced operating expenses; and (2) the need for additional rate cases is reduced. Felsenthal Reb., NS-PGL Ex. AF-1.0 at 14:296-297, 15:316-328. Negative pension expense benefits investors only to the extent it reduces cash funding requirements – there is no immediate cash benefit. *Id.* at 14:297-299.

However, 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. That serves as an incentive for Peoples Gas to make only the minimum required

pension plan contribution, which results in greater risk to employees as to the availability of sufficient pension plan funds to pay ultimate plan benefits. *Id.* at 20:426-428. It is also 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).

The Commission should encourage adequate pension plan funding, not send signals to do less. In its Order in ICC Docket No. 05-0597, a Commonwealth Edison Company ("ComEd") rate proceeding, with respect to a $803 million contribution made by ComEd's parent company to ComEd's pension plan, the Commission acknowledged that "the 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.

Recently, the Illinois Appellate Court for the Second Judicial District issued an opinion that affirmed the Commission's decision in ComEd's 2005 rate case (ICC Docket No. 05-0597) that excludes ComEd pension asset from rate base but allows 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.[47] *ComEd 2005 Appeal* at 17. 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. *Id*. at 16-17. Therefore, the question on appeal did not revolve around whether the funds used to contribute to

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

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.

Mr. Felsenthal testified that 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 as direct. Felsenthal Reb., NS-PGL Ex. AF-1.0 at 27:575-576.

> [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.

Thus, neither the Commission's decision in ComEd's 2005 rate case nor *ComEd 2005 Appeal* supports denying Peoples Gas a rate of return on its pension asset. Moreover, given the evidence, the appropriate rate of return on the pension asset is the utility's overall cost of capital.

For the same reasons that it is appropriate to include the pension asset in Peoples Gas' rate base, North Shore's pension liability should be included in its rate base. In fact, because Peoples Gas' pension asset, North Shore's pension liability, and the Utilities' OPEB 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. The accrued pension asset and pension liability, along with the OPEB liabilities, should be included in rate base. However, alternatively, if the Commission concludes that the Peoples Gas pension asset should not be included in its rate base, then North Shore's pension liability should be excluded, and the Utilities' respective OPEB liabilities should excluded. AG-CUB-City witness Mr. Effron agrees that there should be consistent treatment of Peoples

Gas' pension asset and North Shore's pension liability and he does not consider either one in his calculation of the Utilities' rate bases. Effron Dir., AG-CUB-City Ex. 1.0 at 12:254-255.

## V. OPERATING EXPENSES

### A. Overview/Summary/Totals

#### 1. North Shore

North Shore in its surrebuttal testimony presented revised operating expenses and operating income figures of $67,004,000 and $16,301,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part and certain updates. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 2:35-42, 3:46-54, *et seq.*; NS-PGL Ex. SM-3.1N (Sched. C-1); NS-PGL Ex. SM-3.2N (Sched. C-2); Schott Sur., NS-PGL Ex. JFS-3.0 at 6:121-125; NS-PGL Ex. JFS-3.1.

North Shore's operating expenses are supported by extensive, detailed evidence, including the testimony of Sharon Moy (the overall revenue requirement, operating expenses, and operating income and the underlying calculations and supporting various components of operating expenses);[48] Christine Gregor (the test year forecast, including the Annual Operating Budget, and various components);[49] John Spanos (the depreciation study);[50] Michael Small (affiliated interests expenses);[51] James Hoover (incentive compensation expenses);[52] and Christine Phillips (updating the pension and OPEB expenses figures).[53]

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[48] Moy Dir., NS Ex. SM-1.0; NS Ex. SM-1.1; Moy Reb., NS-PGL Ex. SM-2.0; NS-PGL Exs. SM-2.1N, SM-2.2N, SM-2.3N, SM-2.4N, SM-2.5N, SM-2.6N, SM-2.7N, SM-2.8N, SM-2.9N; Moy Sur., NS-PGL Ex. SM-3.0 Rev.; NS-PGL Exs. SM-3.1N, SM-3.2N, SM-3.3N, SM-3.4N, SM-3.5N, SM-3.6N, SM-3.7N, SM-3.8N.

[49] Gregor Dir., NS Ex. CMG-1.0; NS Ex. CMG-1.1; Gregor Reb., NS-PGL Ex. CMG-2.0; NS PGL Exs. CMG-2.1N, CMG-2.2N, CMG-2.3N, CMG-2.4N, CMG-2.5N, CMG-2.6N; Gregor Sur., NS-PGL Ex. CMG-3.0; NS-PGL Exs. CMG-3.1N, CMG-3.2N.

[50] Spanos Dir., NS Ex. JJS-1.0; NS Ex. JJS-1.1.

[51] Small Dir., NS Ex. MAS-1.0.

The Commission should approve North Shore's operating expenses. North Shore is entitled to recover these proven costs through its rates.

### 2. Peoples Gas

Peoples Gas in its surrebuttal testimony presented revised operating expenses of $455,540,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part and certain updates. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 2:35-42, 3:46-54, *et seq.*; NS-PGL Ex. SM-3.1P (Sched. C-1); NS-PGL Ex. SM-3.2P (Sched. C-2); Schott Sur., NS-PGL Ex. JFS-3.0 at 6:121-125; NS-PGL Ex. JFS-3.1.

Peoples Gas' operating expenses are supported by extensive, detailed evidence, including the testimony of Sharon Moy (the overall revenue requirement, operating expenses, and operating income and the underlying calculations and supporting various components of operating expenses);[54] Christine Gregor (the test year forecast, including the Annual Operating Budget, and various components);[55] John Spanos (the depreciation study);[56] Michael Small (affiliated interests expenses);[57] James Hoover (incentive compensation expenses);[58] Edward

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[52] Hoover Reb., NS-PGL Ex. JCH-1.0; Hoover Sur., NS-PGL Ex. JCH-2.0.

[53] Phillips Reb., NS-PGL Ex. CMP-1.0; NS-PGL Exs. CMP-1.1, CMP-1.2, CMP-1.3.

[54] Moy Dir., PGL Ex. SM-1.0; PGL Ex. SM-1.1; Moy Reb., NS-PGL Ex. SM-2.0; NS-PGL Exs. SM-2.1P, SM-2.2P, SM-2.3P, SM-2.4P, SM-2.5P, SM-2.6P, SM-2.7P, SM-2.8P, SM-2.9P, SM-2.10P. Moy Sur., NS-PGL Ex. SM-3.0 Rev.; NS-PGL Exs. SM-3.1P, SM-3.2P, SM-3.4P, SM-3.5P, SM-3.6P, SM-3.7P, SM-3.8P, SM-3.9P, SM-3.10P.

[55] Gregor Dir., PGL Ex. CMG-1.0 Rev.; PGL Ex. CMG-1.1; Gregor Reb., NS-PGL Ex. CMG-2.0; NS-PGL Exs. CMG-2.1P, CMG-2.2P, CMG-2.3P, CMG-2.4P, CMG-2.6P; Gregor Sur., NS-PGL Ex. CMG-3.0; NS-PGL Exs. CMG-3.1P, CMG-3.2P.

[56] Spanos Dir., PGL Ex. JJS-1.0; PGL Ex. JJS-1.1.

[57] Small Dir., PGL Ex. MAS-1.0.

[58] Hoover Reb., NS-PGL Ex. JCH-1.0; Hoover Sur., NS-PGL Ex. JCH-2.0.

Doerk (responding to two proposed adjustments to Peoples Gas' distribution operating expenses);[59] James Schott (also responding to one of those adjustments);[60] and Christine Phillips (updating the pension and OPEB expenses figures).[61]

The Commission should approve Peoples Gas' operating expenses. Peoples Gas is entitled to recover these proven costs through its rates.

### B. Uncontested Issues

#### 1. Natural Gas Prices for Purposes of Company Use Gas, Uncollectibles Expense, and North Shore Franchise Gas

The Utilities, Staff, AG, and CUB agree that the natural gas prices for the purposes of company use gas, uncollectibles expense, and North Shore's franchise gas should be updated based upon data in the Utilities' August Gas Charge Filings.[62]

#### 2. Union Wages (Falls in Multiple Categories of O&M)

Staff proposed to reduce the rate bases of North Shore and Peoples Gas by $15,000 and $98,000, respectively, and operating expenses of North Shore and Peoples Gas by $69,000 and $582,000 (before income taxes), respectively, to correct an error in calculating test year union wages at the non-union rate.[63] AG-CUB-City and the Utilites agreed.[64] No witness disagreed.

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[59] Doerk Reb., NS-PGL Ex. ED-2.0; Doerk Sur., NS-PGL Ex. ED-3.0.

[60] Schott Reb., NS-PGL Ex. JFS-2.0; NS-PGL Ex. JFS-2.1; Schott Sur., NS-PGL Ex. JFS-3.0, NS-PGL Ex. JFS-3.1.

[61] Phillips Reb., NS-PGL Ex. CMP-1.0; NS-PGL Exs. CMP-1.1, CMP-1.2, CMP-1.3.

[62] Gregor Sur., NS-PGL Ex. CMG-3.0 at 2:35-3:65, 5:93-95, 6:110-119, 127-128; Moy Sur., NS-PGL Ex. 3.0 Rev. at 7:147-8:170; Effron Reb., AG-CUB Ex. 4.0 at 9:158-10:176, 11:196-201, 12:211-217; Seagle Reb., Staff Ex. 27.0 at 17:323-19:350, 19:351-20:376; Rearden, Tr. at 914:19-915:7.

[63] Hathhorn Dir., Staff Ex. 1.0 at 29:684-689, Sched. 1.2 P, p. 1, col. (e), Sched. 1.4 P, p. 1, col. (d), Sched. 1.2 N, p. 1, col. (e), and Sched. 1.4 N, p. 1, col. (d).

[64] Effron Dir., AG-CUB-City Ex. 1.0 at 17:367-371; Moy Reb., NS-PGL Ex. SM-2.0 at 4:78, 5:104; Hengtgen Reb., NS-PGL Ex. JH-2.0 at 4:69.

### 3. Company Use Gas (Falls in Multiple Categories of O&M)

AG-CUB's proposal to include North Shore's cost of company use gas for 2010 test year, which was inadvertently omitted from North Shore's Part 285 filing, is uncontested. Effron Dir., AG-CUB-City Ex. 1.0 at 23:513-514; Gregor Reb., NS-PGL CMG-2.0, Sched. 2.6N. For the update of the gas price, please see Section V(B)(1) of this Initial Brief, *supra*.

### 4. IBS Charges (Falls in Multiple Categories of O&M)

AG-CUB's proposal to reduce the operating and maintenance expenses of North Shore and Peoples Gas by $360,000 and $7,493,000 (gross amounts), respectively, for test year 2010 for IBS charges based on the Utilities' responses to Staff data request DLH 4.06 is uncontested. Effron Dir., AG-CUB-City Ex. 1.0 at 16:339-17:361; Moy Reb., NS-PGL Ex. SM-2.0 at 5:109.

### 5. Distribution

#### a. Gasoline and Fuel

Staff witness Mr. Seagle originally proposed to decrease the Utilities' transportation fuel costs for the test year. Seagle Dir., Staff Ex. 13.0 at 13:245-17:311. The Utilities corrected and updated Staff's calculations. Gregor Reb., NS-PGL Ex. CMG-2.0 at 7:137-155. Mr. Seagle agreed with the revised adjustments. Seagle Reb., Staff Ex. 27.0 at 3:40-42.

### 6. Customer Accounts

#### a. Uncollectibles Expense Except for AG-CUB Sales Revenues Adjustment-Related

There is no contested issue regarding uncollectibles expenses, except for the derivative impact of AG-CUB's proposed sale revenues adjustment discussed in Section V(C)(5), *infra*.[65]

[65] The only aspect of uncollectibles expenses as such that was at issue in these cases was the impact of natural gas prices, but the Utilities, Staff, and AG-CUB ultimately agreed on that subject. *See* Section V(B)(1), *supra*.

### 7. Administrative & General Expenses

#### a. Account 921

Staff proposed adjustments to limit the amount of test year amount of Office Supplies and Expenses. Ostrander Dir., Staff Ex. 3.0 at 8:155-10:206. The Utilities revised Staff's adjustments. Gregor Reb., NS-PGL Ex. CMG-2.0 at 4:82 - 5:100. Staff accepted the revisions. Ostrander Reb., Staff Ex. 17.0 at 3:47-58. No witness opposed the revised adjustments.

#### b. Interest on Budget Payment Plans

Staff's proposal to decrease operating and maintenance expenses of North Shore and Peoples Gas by $118,000 and $618,000, respectively, is uncontested. Ostrander Dir., Staff Ex. 3.0 at 13:248 - 14:283; Moy Reb., NS-PGL Ex. SM-2.0 at 5:95.

#### c. Interest on Customer Deposits

Staff witness Mr. Ostrander's proposal to decrease operating and maintenance expenses of North Shore and Peoples Gas by $85,000 and $950,000, respectively, is uncontested. Ostrander Dir., Staff Ex. 3.0 at 14:284 - 16:316; Moy Reb., NS-PGL Ex. SM-2.0 at 5:96.

#### d. Lobbying

Staff's proposal to reduce operating and maintenance expenses of North Shore and Peoples Gas by $2,000 and $12,000, respectively, in order to disallow lobbying costs included in the dues paid by the Utilities to the American Gas Association is uncontested. Wilcox Dir., Staff Ex. 6.0 at 3:53 - 4:66; Moy Reb., NS-PGL Ex. SM-2.0 at 5:100.

#### e. Social and Service Club Dues

Staff's proposal to reduce operating and maintenance expenses of North Shore and Peoples Gas by $8,000 and $52,000, respectively, for certain service club membership dues is uncontested. Wilcox Dir., Staff Ex. 6.0 at 4:67-80; Moy Reb., NS-PGL Ex. SM-2.0 at 5:102.

### f. Civic, Political, and Related Activities

Staff's proposal to reduce the rate bases of North Shore and Peoples Gas by $6,000 and $14,000, and their operating and maintenance expenses by $10,000 and $23,000 (gross amounts), respectively, for expenses associated with lobbying and related activities is uncontested. Wilcox Dir., Staff Ex. 6.0 at 6:118 - 7:136; Moy Reb., NS-PGL Ex. 2.0 at 5:101; Hengtgen Reb., NS-PGL Ex. JH-2.0 at 4:72.

### g. Non-union Base Wages Adjustment in DLH–4.06 (PGL)

Staff proposed an adjustment to operating expenses to reduce the operating expenses of North Shore and Peoples Gas by $23,000 and $5,947,000, respectively, for non-union wages relating to IBS based on the Utilities' response to Staff data request DLH 4.06. Hathhorn Dir., Staff Ex. 1.0 at 29:691-697. Staff also proposed an adjustment to reduce the operating expenses of North Shore and Peoples Gas by $291,000 and $1,304,000, respectively, for external contractor costs. Pearce Dir., Staff Ex. 2.0 at 7:143-151. The Utilities agreed. Moy Reb., NS-PGL Ex. SM-2.0 at 4:87-88, 4:92-93. No witness opposed these adjustments.

### h. Liberty Audit Outside Contractor Fees (PGL)

Staff and AG-CUB proposed an adjustment to reduce Peoples Gas' operating and maintenance expense by $540,000 to remove the fees of certain consultants related to the Liberty audit follow up work. Hathhorn Dir., Staff Ex. 1.0 at 32:775-33:785 and Sched. 1.13 P, line 1; Effron Dir., AG-CUB-City Ex. 1.0 at 25:550-553. The Utilities agreed. Moy Reb., NS-PGL Ex. SM-2.0 at 4:83-85, 5:105-107. No witness opposed this adjustment. The Utilities contest Staff's other adjustment related to the audit. *See* Section V(C)(4)(a), *infra*.

### i. Rate Case Expenses

Staff recommends that the Commission find the amounts expended by the Utilities for rate case expense in this proceeding are just and reasonable pursuant to Section 9-229 of the Public Utilities Act (220 ILCS 5/9-229). Ostrander Reb., Staff Ex. 17.0 at 14:275 - 15:295. The Utilities agreed. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 4:77-80.

AG-CUB witness Mr. Effron proposed an adjustment to reduce Peoples Gas' rate case expenses on the theory that there was a double counting of certain costs. AG-CUB-City Ex. 1.0 at 25:559 - 26:565. Utilities witness Ms. Moy explained and showed that there was no double counting. Moy Reb., NS-PGL SM-2.0 at 8:164-178. Mr. Effron then agreed that his adjustment was not necessary. Effron Reb., AG-CUB Ex. 4.0 at 11:204 - 12:209.

### j. Franchise Gas Requirements (NS)

AG-CUB proposed an adjustment to reduce North Shore's franchise requirement expenses. AG-CUB-City Ex. 1.0 at 26:567-580. Ms. Gregor updated the adjustment as discussed in Section V(B)(1), *supra*. Gregor Reb., NS-PGL Ex. CMG-2.0 at 8:162-172. Mr. Effron agreed with the updated adjustment. Effron Reb., AG-CUB Ex. 4.0 at 12:211-217.

### k. Regulatory Asset – Welfare

Staff and AG-CUB proposed adjustments to the amortization of regulatory assets for welfare costs, which the Utilities accepted. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 1:17-20, 2:40-42, 4:83-84. The adjustmnts are uncontested.

### l. Regulatory Asset – Pension

Utilities witness Ms. Moy proposed corrected adjustments relating to the amortization of regulatory assets for pension costs. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 6:135-7:143. The adjustments are uncontested.

#### m. Employee Benefits Update

The Utilities provided updated 2010 test year numbers for the Utilities' respective pension and benefits expenses figures in their operating expenses. Phillips Reb., NS-PGL Ex. CMP 1.0 (in its entirety). No witness opposed those updates.

#### n. Merger Costs and Savings

Staff proposed adjustments to reconcile the most recent actual and projected Costs to Achieve with the total recovery of merger costs since the effective date of the tariffs approved in Peoples Gas' and North Shore's last rate cases. Pearce Dir., Staff Ex. 2.0 at 7:153-161. In rebuttal, Staff revised the adjustments. Pearce Reb., Staff Ex. 16.0 at 16:383 - 18:438. In surrebuttal testimony, Ms. Moy agreed with Staff's calculations to reconcile total merger costs expected to recover with actual costs incurred but using July 31, 2009 forecast data in NS-PGL Exs. SM 3.8N and SM-3.8P. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 6:125-130. Staff agreed with the revised adjustments in NS-PGL Cross Ex. Pearce 25. No contested issue remains.[66]

### 8. Depreciation

#### a. Inventory Reclassification

Staff witness Ms. Hathhorn's proposal to reduce the operating expenses of North Shore and Peoples Gas by $2,000 and $18,000, respectively, in order to reflect the impact of inventory reclassifications is uncontested. Hathhorn Dir., Staff Ex. 1.0 at 30:703-712, Scheds. 1.11 N and 1.11 P; Moy Reb., NS-PGL Ex. SM-2.0 at 4:79. *See also* Section IV(B)(3)(a), *supra*.

[66] Because they were not reflected in NS-PGL Exs. SM-3.1N and SM-3.1P, Revised Schedules C-1, and NS-PGL Exs. SM-3.2N and SM-3.2P, Revised Schedules C-2, the adjustments should be reflected accordingly in the final Order in this proceeding. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 6:130-134.

#### b. IBS Mainframe

AG-CUB's proposal to amortize the remaining book value of the IBS mainframe server as of the beginning of 2010 over three years is uncontested. Effron Dir., AG-CUB-City Ex. 1.0 at 24:519 - 25:546; Moy Reb., NS-PGL Ex. SM 2.0 at 5:111.

### 9. Taxes Other Than Income Taxes

#### a. Real Estate Taxes

Staff's proposal to decrease the expense for real estate taxes of North Shore and Peoples Gas by $45,000 and $207,000, respectively, to reflect actual 2008 real estate taxes is uncontested. Bridal Dir., Staff Ex. 5.0 at 4:72-6:125; Moy Reb., NS-PGL Ex. SM-2.0 at 5:98.

### 10. Revenues

#### a. Accounting Charge Revenues

The Utilities proposed that the natural gas prices for the purposes of accounting charge revenues be updated based upon data in the Utilities' August Gas Charge filing, as with the other items. Moy Sur., NS-PGL Ex. 3.0 Rev. at 8:170-175. The Utilities believe this is uncontested.

### 11. Gross Revenue Conversion Factor

The Utilities' Gross Revenue Conversion Factors (the amounts by which the rate increases must be increased for income taxes and uncollectibles to allow recovery of the costs of service) are uncontested. NS Ex. SM-1.1 at Sched. A-2; PGL Ex. SM-1.1 at Sched. A-2.

## C. Contested Issues

### 1. Incentive Compensation (Falls in Multiple Categories of O&M)

Staff and AG-CUB propose to disallow nearly all of the Utilities' incentive compensation program costs in operating expenses and rate base. Their proposals are without merit. Because

of the complexity of the proposed disallowances, the Utilities will begin their discussion by setting forth the proposals and briefly identifying the grounds. After that, the Utilities will discuss the multiple fatal flaws of the proposals.

**a. Staff's Proposals and Grounds**

Totals. Staff proposes to disallow the following incentive compensation program costs:

| | Operating Expenses (Before Income Taxes) ("OE") | Rate Base ("RB")* |
|---|---|---|
| PGL | $8,686,000 | $573,000 |
| NS | $1,882,000 | $108,000 |

Sources: Hathhorn Reb., Staff Ex. 15.0 at Sched. 15.2 P Corr., p. 1, col. (c), Sched. 15.4 P Corr., p. 1, col. (b), Sched. 15.2 N, p. 1, col. (c), Sched. 15.4 N, 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. Staff's Peoples Gas proposals involve four "buckets" of disallowed costs plus certain derivative impacts.

| | OE Disallowances | RB Disallowances |
|---|---|---|
| Non-executive Plan Costs | $4,218,000 out of $4,280,000; plus $13,000 of depreciation expense for RB disallowances | $509,000 out of $517,000 |
| Executive Plan Costs | $722,000 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] | $664,000 | ($99,000) (accum. deprec.) ($3,000) (ADIT) |
| Totals | $8,686,000 | $573,000 |

Source: Hathhorn Reb., Staff Ex. 15.0 at Sched. 15.7 P.

North Shore Amounts Breakdown. Staff's North Shore proposals also involve four buckets of disallowed costs.

| | OE Disallowances | RB Disallowances |
|---|---|---|
| Non-executive Plan Costs | $989,000 out of $1,071,000; plus $2,000 of depreciation expense for RB disallowances | $97,000 out of $105,0000 |
| Executive Plan Costs | $140,000 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] | $142,000 | ($15,000) (accum. deprec.) ($1,000) (ADIT) |
| Totals | $1,882,000 | $108,000 |

Source: Hathhorn Reb., Staff Ex. 15.0 at Sched. 15.7 N.

Staff's Grounds. In brief: Staff essentially eliminated the non-executive plan costs by disallowing 50% as being for "financial" goals, disallowing 20% of the remainder as unlikely to be achieved, disallowing 74% of the remainder as based on affiliate performance metrics, and disallowing 50% of the remainder because it was based on Integrys net income metrics. Hathhorn Reb., Staff Ex. 15.0, Sched. 15.7 P, p. 3. Staff took the same four steps as to executive plan costs, except the percentages were 70%, 20%, 83%, and 50%, respectively. *Id*. at p. 2. Staff disallowed the stock plans costs as "financial". Hathhorn Dir., Staff Ex. 1.0 at 8:172-173. Staff disallowed the fourth bucket based on the Order in the 2007 rate cases. *Id*. at 8:174-175.

**b. AG-CUB's Proposals and Grounds**

AG-CUB witness Mr. Effron focused on certain incentive compensation costs included in operating expenses. Effron Dir., AG-CUB-City Ex. 1.0 at 19:420 - 425. He proposed to disallow $4,567,000 out of $5,620,000 as to Peoples Gas and $944,000 out of $1,072,000 as to North Shore. *Id*. at 21:455-462; AG-CUB Ex. 4.2 at Sched. C-2 Corr.; AG-CUB Ex. 4.1 at Sched. C-2 Corr. He reached these figures on the basis of proposing to disallow 50% of the

incentive compensation paid directly to employees as "financial" and 100% allocated from affiliates as "financial". Effron Dir., AG-CUB-City Ex. 1.0 at 20:426 - 21:462.

### c. **Staff's and AG-CUB's Proposals Lack Merit**

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.[67] 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; (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; and (3) attracting and retaining such a work force benefits customers by making sure there are enough employees to perform needed work, by maintaining and improving the quality of work, and reducing the expenses associated with recruiting and retaining new employees. *E.g.*, Hoover Reb., NS-PGL Ex. JCH-2.0, 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-2.0 at 7:141-151.

Mr. Hoover's testimony also established, among other things, that:

[67] 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.

- 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 income metrics in prior cases, it has approved cost control metrics.[68] 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.
- 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.[69]

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[68] 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).

[69] 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.

The Commission cannot ignore the uncontradicted evidence regarding the prudence and reasonableness of the incentive compensation costs or the benefits received by customers. The Commission 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).[70]

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 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*, 116 Ill. 2d at 121.

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[70] *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).

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., Villages of Milford v. Illinois Commerce Comm'n*, 20 Ill. 2d 556, 565 (1960) ("*Milford*").

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 (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.

Previously, in the 2005 ComEd rate case (ICC Docket No. 05-0597), 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) ("*ComEd 2005*") 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, adding 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. 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)]. 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.[71]

Here, however, unlike the ComEd case, the numbers set forth above show that Staff proposes to disallow almost 100% of the Utilities' incentive compensation costs, even though they include some "operational" metrics, such as metric tied to system leak reductions. Thus, the "tangential benefit" and "apportionment" reasoning of the Second District does not apply here.

The Commission should reject Staff's and AG-CUB's proposed disallowances. The costs at issue are prudent and reasonable, and they benefit customers in multiple respects.

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[71] 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.

### 2. <u>Non-union Base Wages</u> (Agreed in Part) (Falls in Multiple Categories of O&M)

Staff and the Utilities agree to certain reductions in the Utilities' non-union base wages that the Utilities accepted in their rebuttal testimony, but Staff proposes to reduce even further both Peoples Gas' and North Shore's non-union base wages. Staff's proposal for further decreases lacks merit and should not be adopted.

Staff appropriately proposed, based on data request responses of the Utilities, to reduce non-union base wages in charges from Integrys Business Support to the Utilities (the reductions were among the cost control measures adopted in light of the economic downturn) and to make a correction that reduced Peoples Gas' non-union base wages. The Utilities accepted and incorporated those reductions in their rebuttal testimony. Moy Reb., NS-PGL Ex. SM-2.0 at 4:87-90 and fn. 3. That was discussed in Section V(B)(7)(g) of this Initial Brief, *supra*.

Staff also proposes, however, to reduce the 2010 test year non-union base wages based on a two-step methodology that starts with the 2008 actual amounts and then escalates them for each of 2009 and 2010 using a 2.2% inflation rate, based on general Consumer Price Index ("CPI") inflation data that became available in May 2009. Hathhorn Reb., Staff Ex. 15.0 at 19:432 - 20:443 and Scheds. 15.8N and 15.8P.

Staff's proposal as to the 2009 step is erroneous and unreasonable. Staff proposes to escalate the Utilities' 2009 non-union base wages from 2008 actual levels based on general Consumer Price Index ("CPI") inflation data that became available in May 2009, but the Utilities increased their non-union base wages for 2009 in February 2009, three months before Staff's data became available. Hoover Sur., NS-PGL Ex. JCH-2.0 at 5:91-93. Utilities witness James Hoover, testified that it was inappropriate to "retroactive[ly]" look back on the February 2009

increases based on general CPI data from May 2009, and that the lower level of wage increases that Staff hypothesizes would result in non-competitive salaries. *Id*. at 5:88-98.

Staff's proposal also is flawed as to both 2009 and 2010 because of its reliance on general CPI information and its rejection of labor market data. Mr. Hoover testified that reliance on that general CPI data for this purpose is not realistic given the facts of these cases. Hoover Reb., NS-PGL Ex. JCH-1.0 at 9:198-199. The Utilities' forecasts relied on market data provided by the World at Work 2008-2009 Salary Budget Survey and input from Towers Perrin human resources consultants, subject to the reductions made as part of the cost control measures. *Id*. at 9:199 - 10:216. "The World At Work Salary Budget Survey is a well-known compensation tool that reports results of annually surveyed information on planned increases for the following budget year. They use information submitted by corporations in all industries and reported in the aggregate to assist in corporate salary budget planning." *Id*. at 10:202-206. There is no valid basis for rejecting labor market data actually used by the Utilities in making human resources decisions and supported by a human resources expert in favor of general CPI information supported by a witness who is not an expert in this subject. That the Commission, based on other evidentiary records, has relied on general CPI information in other cases in determining salaries and wages adjustments (Hathhorn Reb., Staff Ex. 15.0 at 20:450-452) is not a reasonable basis for doing so given the evidence in the instant cases.

Finally, Mr. Hoover's testimony that the increases proposed by Staff for both 2009 and 2010 would result in non-competitive salaries (Hoover Reb., NS-PGL Ex. JCH-1.0 at 10:214-216; Hoover Sur., NS-PGL Ex. JCH-3.0 at 5:88-98) is uncontradicted.

Staff's proposal for further reductions in the Utilities' non-union base wages, beyond those accepted in the Utilities' rebuttal testimony, are not justified and should be rejected.

### 3. <u>Headcounts</u> (Falls in Multiple Categories of O&M)

AG-CUB witness Mr. Effron proposes a disallowance based on his conclusion that Peoples Gas and North Shore will not have as many employees as they forecast. Mr. Effron's evidence is rather thin on this point, however. As of mid-2009, Peoples Gas' employee headcount had not risen appreciably from 2008 levels, so Mr. Effron therefore theorized that it also would not increase by the test year, 2010. Effron Dir., AG-CUB-City Ex. 1.0 at 17:377 – 18:385; Effron Reb., AG-CUB Ex. 4.0 at 8:134-42.

Mr. Effron's "trend line" analysis, without more, cannot overcome Peoples Gas' testimony indicating that it would be hiring more employees.[72] Aside from the budget, Peoples Gas' Vice President of Gas Operations testified that Peoples Gas had specific plans to bring on new employees, in large part to comply with Commission orders. Doerk Reb., NS-PGL Ex. ED-2.0 at 6:130 – 7:137. In fact, 36 of the 47 new employees will directly relate to addressing the safety recommendations of Liberty Consulting in their August 2008 report. *Id*. Mr. Doerk was able to update the status of the new hires in his rebuttal testimony drafted in August. Since June 2009 (and therefore post-dating the information on which Mr. Effron relied), Peoples Gas has now hired 27 new Operations Apprentices and 5 new Operations Specialists, and is interviewing additional candidates. Doerk Sur., NS-PGL Ex. ED-3.0 at 3:62 – 4:66. That demonstrates that Peoples Gas' forecast is realistic, that it is not going to ignore the Liberty recommendations, and that Mr. Effron's proposed decrease should be rejected. The Commission rejected Mr. Effron's proposed headcount adjustment in *Nicor 2008* at 36-37.

[72] North Shore did not submit additional evidence, but it contests this adjustment. The difference between North Shore's planned headcount and Mr. Effron's prediction is only three employees, amounting to a disallowance of $137,000; Effron Dir., AG-CUB-City Ex. 1.0 at 19:404-06. See Hathhorn Reb., Staff Ex. 15.0 at 31:698 – 32:711. There is no persuasive reason to reject North Shore's forecast.

### 4. Distribution Expenses

#### a. Liberty Audit-Related Expenses (PGL)

Staff proposes a reduction of $5 million of 2010 test year operating expenses based on the Commission's order in *Illinois Commerce Comm'n on its Own Motion v. The Peoples Gas Light and Coke Co.*, ICC Docket No. 06-0311 (Order Dec. 20, 2006), at 6, which stated, in brief, that Peoples Gas would not recover, in its next rate case, costs solely attributable to not performing corrosion inspections in a timely manner or incremental costs due solely to violations of the Pipeline Safety Act. Hathhorn Dir., Staff Ex. 1.0 at 31:729 – 33:802, 35:829-837. The proposed disallowance should be rejected for two reasons. First, the record is clear that Peoples Gas did not include any such incremental costs in its test year operating expenses. *See* Doerk Reb., NS-PGL Ex. 2.0 at 7:153-157. Second, the disallowance is "based" on an arbitrary figure.

In ICC Docket No. 06-0311, the Commission found that Peoples Gas needed to improve its corrosion protection activities. The case ended with a stipulation between Peoples Gas and Staff that formed the basis for the Commission's final Order. Using the agreed language from the stipulation, the Commission held, in relevant part, as follows:

> pursuant to its agreement in the Stipulation, Peoples Gas shall not seek recovery, in any future rate or reconciliation proceeding before the Commission, of costs or expenses solely attributable to Peoples Gas' not performing corrosion inspections in a timely manner, as specified in paragraph 4 above, or any incremental costs caused solely by violation of the Illinois Gas Pipeline Safety Act or its implementing regulations ("the Act") discovered by the Commission's consultant retained pursuant to the Memorandum of Understanding, and which are over and above the prudent and reasonable costs necessary to comply with the Act. Peoples Gas shall operate an internal tracking mechanism to account for any such incremental costs.

Final Order, ICC Docket No. 06-0311, Ordering Paragraph 11.

In response to Staff's allegations in ICC Docket No. 06-0311 and to the Commission's order, Peoples Gas undertook to improve its corrosion protection program, among other things

hiring additional staff with better and more specific training. Burk Reb., Staff Ex. 23 at 9:199 – 10:210; Doerk Sur., NS-PGL Ex. 3.0 at 8:163 – 9:169. The Staff and Peoples Gas witnesses agreed that these steps have improved Peoples Gas' compliance with the Pipeline Safety Act. Burk, Tr. at 942:15 – 945:3; Doerk Sur., NS-PGL Ex. ED-3.0 at 8:155-159. Neither witness cited any outages, reliability problems, fires, explosions, leaks, or other similar problems caused by Pipeline Safety Act violations since the final order in Docket 06-0311. Indeed, Mr. Doerk, who said it would definitely come to his attention as head of operations if such problems occurred, affirmatively stated that there were no such events. Doerk Reb., NS-PGL Ex. ED-2.0 at 7:153 – 8:163; Doerk, Tr. at 639:6 – 640:6.

Given these facts, no disallowance is proper as there were no incremental costs to track and write off. Both Staff and Peoples Gas interpret their stipulation, and the Commission's order, the same way. If Peoples Gas did have something go wrong, due to a violation of the Pipeline Safety Act, and it cost incremental money to fix it, that money would have to be tracked. Burk, Tr. at 941:16 – 942:2. As discussed above, there were no such incremental costs, however. If Peoples Gas acted prudently and reasonably to come into compliance, for example by hiring extra inspectors, the salaries of those inspectors would *not* need to be tracked and excluded. Burk, Tr. at 942:3-14. The clear and undisputed evidence is that the only costs Peoples Gas incurred were these type of reasonable and prudent costs of complying with the Pipeline Safety Act. Doerk Reb., NS-PGL Ex. ED-2.0 at 7:153-157; Doerk Sur., NS-PGL Ex. ED-3.0 at 7:135-138. For each of the things cited by Mr. Burk as a violation based on the findings of the Liberty Audit, Mr. Burk agreed that Peoples Gas addressed those violations using reasonable means to comply with the Pipeline Safety Act. Burk, Tr. at 942:15 – 945:3. What Peoples Gas did not do was to let the problems go, leading to incremental costs attributable to

violations. Accordingly, there were no incremental expenses to track, and no incremental expenses to exclude from test year operating expenses.

Ms. Hathhorn testified in support of Staff's proposed disallowance. Noting that there was no tracking mechanism in place, and therefore no quantification of costs, she arbitrarily decided to make a disallowance of 5% of Peoples Gas' entire test year distribution costs. She appears to conclude that the Commission's Order in ICC Docket No. 06-0311 required that Peoples Gas develop a tracking mechanism even if there were no relevant costs to track. Peoples Gas disagrees with this interpretation. If relevant costs were incurred a tracking mechanism would have been instituted. There is no evidence in the record to support a need for a tracking mechanism or any such disallowance,[73] or suggesting a relationship between all distribution costs and the costs covered by the stipulation in ICC Docket No. 06-0311. Her proposed disallowance is therefore improper. What is more, whereas Mr. Burk is the architect and chief enforcer of the Commission's Order in ICC Docket No. 06-0311 (Burk, Tr. at 939:6 – 940:11), Ms. Hathhorn is an accountant. It is clear from her testimony that she misunderstood the scope of the expenses to be excluded under the order. She erroneously described her disallowance as "costs to come into compliance with the Liberty audit findings," "test year costs resulting from the Liberty Audit," and "costs to comply with the Liberty Audit." Hathhorn Dir., Staff Ex. 1.0 at 34:804 – 35:837. As Mr. Burk agreed, Peoples Gas could incur costs to come into compliance, but so long as those costs were reasonable and prudent, they would not be disallowed. Tr. at 941:8 – 942:9. Staff's disallowance should be rejected.

[73] Peoples Gas and Staff do agree on one cost that should be excluded from test year operating expenses. Peoples Gas spent $540,000 on fees to consultants that were erroneously included in the operating expenses in Peoples Gas' initial filing. That was corrected in the Utilities' rebuttal. *See* Section V(B)(7)(h), *infra*.

### 5. Customer Accounts

#### a. Uncollectibles Expense Related to Sales Revenues Adjustment

AG-CUB witness Mr. Effron's proposed adjustments to increase the Utilities' forecasted sales are without merit, as discussed in Section V(C)(5)(a), *infra*. If the Commission were to adopt those adjustments, however, then the Utilities' uncollectibles expense figures would need to be increased to reflect the hypothesized increased sales, as discussed in that Section.

### 6. Customer Service and Information

#### a. Advertising (Agreed in Part)

Staff witness Mr. Wilcox proposed an adjustment to reduce operating and maintenance expenses for certain advertising expenses that he concluded were of a promotional, goodwill or institutional nature. The Utilities agreed in part with Mr. Wilcox's adjustment, only taking exception to his disallowance of the costs associated with their Safety, Reliability and Warmth Campaign ("SRW Campaign"). Moy Reb., NS-PGL Ex. SM-2.0 at 6:140 - 7:160. The disallowance of the "SRW" portion is contrary to the evidence.

Section 9-225 of the Public Utilities Act (220 ILCS 5/9-225) states that the Commission cannot consider promotional, political, institutional or good will advertising in a general rate increase requested by an utility. 200 ILCS 5/9-225(2). Staff claims that the SRW costs are the type of promotional adverting costs that the Commission is prohibited from considering. Wilcox Dir., Staff Ex. 6.0 at 6:115-117.

However, there is nothing in the record that establishes that this advertising campaign is intended to "encourage any person to select or use the service or additional service of a utility or the selection or installation of any appliance or equipment designed to use such utility's service." 220 ILCS 5/9-225(1)(c). The record for the opposite conclusion is clear. The SRW campaign

informs and educates customers regarding energy conservation and safety measures. 220 ILCS 5/9-225(a), (c).

By focusing on the words, Safety, Reliability, and Warmth in the advertising campaign, the Utilities educated customers on the Utilities' services offered and benefits provided to customers. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 5:103-105. The energy education advertising in the SRW Campaign focused on three main customer benefits: (1) conserving/managing home natural gas use, (2) billing and payment options, and (3) staying safe and understanding the use and maintenance of the natural gas delivery function. Moy Reb., NS-PGL Ex. SM-2.0 at 7:154-159. This advertising strategy was used to catch customers' attention particularly with respect to energy efficiency management and customer billing options available to fit their budget and lifestyles. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 5:105-107. Even Staff witness Mr. Wilcox admits that there were items of energy education in the posters and radio ads. Wilcox Reb., Staff Ex. 20.0 at 4:83-85. While Mr. Wilcox wants to dismiss the whole campaign because of the strategy used to catch the customers' attention, the main message of this campaign lets customers know that they have options and control how they manage their bills and energy usage. Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 5:111-113. Staff's disallowance should not be adopted.

### 7. Administrative & General

#### a. Injuries and Damages Expenses

Staff, relying on five year averages of actual claims payments for 2004 to 2008 escalated for 2009 and 2010, proposes to decrease injuries and damages expenses by revised figures of $864,000 as to Peoples Gas and $159,000 as to North Shore. Ostrander Reb., Staff Ex. 17.0 at Scheds. 17.2 N and 17.2 P. Staff's "normalization" proposal, which seeks to substitute Staff's

averages for the Utilities' forecasts of injuries and damages expenses, is unwarranted and should not be adopted, for four reasons.

Although the specific numbers have changed, and we deal with a future test year here, the Commission is presented with much the same evidentiary record on the subject of injuries and damages expenses as it was in 2007 Peoples Gas and North Shore rate cases, in which it rejected Staff's proposed adjustments. The Commission there found as follows:

> (4) Commission Analysis and Conclusion
>
> We see from the record that depending on the time periods selected for normalizing, the results will either be fairly representative or skewed. While this Commission has accepted 5-year averaging in other cases, this is obviously not a hard and fast rule. It is always necessary, when gathering any periods of data, to further apply sound and reasoned judgment. Here, we are not persuaded by the correctness of using 5 years of data for reasons that one of these years, i.e., 2002, is clearly and unmistakably different from the others. Further, we perceive that something is inherently wrong in the selection when the results change so drastically when either 3 or 4 year data is considered. So too, we are not convinced that Staff's normalization required the complex methodology that it applied especially where plain averaging has been utilized in past cases. And, we see that the use of averaging also would have produced different results. For all these reasons, and because we are not persuaded that normalization was ever required in this instance, we reject Staff's proposed adjustments.
>
> In the final analysis, the Commission finds that North Shore and Peoples Gas used the correct levels of injuries and damages expenses in calculating their revenue requirements. North Shore appropriately used its unadjusted test year level. Peoples Gas appropriately used its test year level, adjusted for a highly unusual credit recorded in fiscal year 2006 relating to a major claim that occurred in fiscal year 2002. No adjustments need be made.

*Peoples 2007* at 57.

The only real change on this subject from the prior cases is that the Utilities, in an attempt to narrow the issues, have offered to accept Staff's revised figures for injuries and damages

expenses if consistent changes to the reserves for injuries and damages in rate base also are made.[74] Staff has not agreed, however, to those corresponding changes to the reserves.

Staff's proposal, therefore, should be rejected for four reasons. First, as in Peoples Gas' and North Shore's 2007 rate cases, Staff has failed to show that that any "normalization" of injuries and damages expenses was required in the first place. In the instant cases, once again, the figures and averages for the last five years (see the following table) on their face do not support normalization. Rather, they show that the amounts determined by the Utilities' forecasting process are reasonable. Gregor Reb., NS-PGL Ex. CMG-2.0 at 3:56 - 4:76.

| **Actual Claims Payments Data*** | | |
|---|---|---|
| | Peoples Gas | North Shore |
| 2004 | $6,032,000 | $867,000 |
| 2005 | $3,250,000 | $735,000 |
| 2006 | $5,472,000 | $541,000 |
| 2007 | $4,766,000 | $586,000 |
| 2008 | $6,877,000 | $465,000 |
| Five Year Average for 2004 to 2008 Not Escalated for Inflation | $5,279,000 | $639,000 |
| Five Year Average for 2004 to 2008 Escalated for Inflation in 2009 and 2010 Only | $5,590,000 | $676,000 |
| Utilities' Forecasted Amounts for 2010 | $6,454,000 | $835,000 |

*All figures are from Ostrander Reb., Staff Ex. 17.0 at Sched. 17.2 N, p. 2., and Sched. 17.2 P, p. 2.

Second, Staff's decision to base its proposal on five year averages of actual claims payments for 2004 to 2008 is arbitrary, because the selected period lacks any foundation. Staff offered as its sole reason for selecting that data and period that the methodology of using the average of actual claim cash payments over the most recent five years to "normalize" injuries

[74] The Utilities' surrebuttal calculations incorporate Staff's revised figures for their injuries and damages expenses adjustments along with the consistent changes to the reserves. Hengtgen Sur., NS-PGL Ex. JH-3.0 at 2:37-38, 3:60-61, 11:233 - 12:251; Moy Sur., NS-PGL Ex. SM-3.0 Rev. at 1:12-16, 2:35-39, 4:80-83. So, if the Commission does not adopt Staff's proposal, then both sets of adjustments need to be backed out of the Utilities' numbers.

and damages expenses was approved in *In re Central Illinois Light. Co. d/b/a AmerenCILCO, et al.*, ICC Docket Nos. 06-0070, 06-0071, 06-0072 Cons. (Order Nov. 21, 2006) ("*Ameren 2006*"). Ostrander Dir., Staff Ex. 3.0 at 12:239-244. That is not correct. In *Ameren 2006*, the Commission approved a methodology that used an average of actual claims payments and accruals over the most recent five years. *Ameren 2006* at pp. 48-49. Staff did not propose that methodology here. Moreover, in the 2007 cases, as quoted above, the Commission expressly recognized that, while it had used a five year period in other cases, use of a five year period "is obviously not a hard and fast rule". *Peoples 2007* at 57.

Third, Staff's approach also is arbitrary because there is no rationale for choosing the five year period over other periods that could have been selected from the same data on which Staff relied. As to Peoples Gas, had Staff chosen the most recent three year period, its methodology still would have yielded a downward adjustment but it would have been $413,000, not $864,000. *See* Ostrander Reb., Staff Ex. 17.0 at Sched. 17.2 P, p. 2.[75] As to Peoples Gas, had Staff chosen the most recent two year period, its adjustment would have been $290,000. *See id.*[76] As to North Shore, had Staff chosen three or two year periods, the adjustments would have been slightly larger. *See* Ostrander Reb., Staff Ex. 17.0 at Sched. 17.2 N, p. 2. If Staff had chosen four year periods, its proposed adjustments would have been larger for both utilities. *See id.* In the 2007 cases, the Commission, as quoted above, also found, in part: "Further, we perceive that something is inherently wrong in the selection when the results change so drastically when either 3 or 4 year data is considered." *Peoples 2007* at 57. While the variances perhaps are not as drastic here, the same conclusion still should apply.

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[75] (($5,472,000 + $4,766,000 + $6,877,000) ÷ 3) x 1.029 x 1.029 = $6,041,000, rather than Staff's five year figure of $5,590,000.

[76] (($4,766,000 + $6,877,000) ÷ 2) x 1.029 x 1.029 = $6,164,000.

Finally, Staff's proposal, even if it had merit, should not be adopted unless consistent adjustments are made to the Utilities' reserves for injuries and damages in rate base. The Utilities have presented the appropriate related adjustments to the reserves should Staff's proposal be adopted in full, and, in the interests of narrowing the issues, the Utilities remain willing to accept the Staff proposal if the consistent adjustments to the reserves are made. Hengtgen Sur., NS-PGL Ex. JH-3.0 at 11:233 - 12:251. The Staff proposal, even if it were to have merit, is not appropriate without those adjustments to the reserves. *Id.*; Hengtgen Reb., NS-PGL Ex. JH-2.0 at 15:329 - 16:339. Staff's opposition to making the consistent reserve adjustments is capricious. Staff takes the position that the Utilities' forecasts for the injuries and damages reserves should not be modified even though Staff, based on no convincing ground and without presenting any distinction between the two, proposes to throw out the Utilities' forecasts for injuries and damages expenses. *See* Ostrander Reb., Staff Ex. 17.0 at 12:239 - 13:252.

Accordingly, the Commission should either (1) reject the Staff proposal and make no adjustments to the reserves or, alternatively, (2) adopt the Staff proposal and make the consistent adjustments to the reserves. If the Commission adopts the Staff proposal in different amounts, *e.g.*, based on the three year averages, then adjustments to the reserves still should be made but they would need to be modified to be consistent with the expenses changes.

### 8. Revenues

#### a. Sales Revenues Adjustment

AG-CUB witness Mr. Effron proposes to increase the forecasted sales revenues of North Shore by $550,000 and of Peoples Gas by $4,441,000. Effron Dir., AG-CUB-City Ex. 1.0 at 13:285 - 15:320; Effron Reb., AG-CUB Ex. 4.0 at 6:100 - 8:127; AG-CUB Ex. 4.1 at Scheds. C and C-1 Corr.; AG-CUB Ex. 4.2 at Scheds. C and C-1 Corr. Those adjustments would lead to

reduced revenues being collected under the new rates. *E.g.*, Clabots Sur., NS-PGL Ex. DWC-3.0 at 1:15-21, 2:44 - 3:52. The proposal lacks merit and should not be adopted, for five reasons.

There is no sound reason to reject the Utilities' sales forecasts and substitute Mr. Effron's proposal. First, the Utilities' sales forecasts are the product of detailed, thorough forecasting methodologies conducted by, and that were supported in testimony by, experienced forecasters. *See* Marozas Dir., NS Ex. BMM-1.0, and PGL Ex. BMM-1.0; Clabots Dir., NS Ex. DWC-1.0 and PGL Ex. DWC-1.0. In contrast, Mr. Effron apparently has no significant training or experience, if any, as a sales forecaster. *See* Effron Dir., AG-CUB-City Ex. 1.0 at 1:9 - 2:43.

Second, Mr. Effron's proposal improperly selects one factor out of the sales models to update and ignores all other factors, including the "Efficiency Improvements" group of variables, which includes the state of the economy, and which is more powerful than the price factor and drives down usage per customer. Clabots Reb., NS-PGL Ex. DWC-2.0 at 1:15-18, 2:25 - 5:88; Clabots Sur., NS-PGL Ex. DWC-3.0 at 1:16 - 2:35. Because of timing, the economic downturn was not captured in the Utilities' sales forecasts used in their filings. Clabots NS-PGL Ex. Reb., DWC-2.0 at 2:32-39. Updating all of the variables, not just a single results-driven factor, likely would result in lower sales forecasts. *Id*. at 1:17-18; *see also* Clabots, Tr. at 406.

Third, Mr. Effron has a record of incorrectly predicting increased natural gas utilities sales and revenues. In its Order in the 2008 Nicor Gas rate case, the Commission rejected Mr. Effron's proposal to adjust upward the utility's sales forecast. The Commission noted that evidence in the record showed that his approach was less accurate than that of the utility, and that the adoption of his approach in the 2004 Nicor Gas rate case had overstated billing units, causing the utility to suffer an annual revenue loss of $5.4 million since the 2004 case. *Nicor 2008* at 177-190.

Fourth, Mr. Effron overlooks that his proposal, if adopted, would be offset by necessary decreases in the test year revenues the Utilities forecast under their decoupling riders, reducing his adjustments to $28,000 as to North Shore and $489,000 as to Peoples Gas. Grace Sur., NS-PGL Ex. VG-3.0 at 2:39-41, 3:51-54, 21:458 - 22:487; NS-PGL Exs. VG-3.2N and VG-3.2P.

Finally, Mr. Effron's proposal also overlooks that, if adopted, it would require an increase in the Utilities' uncollectibles expense. Gregor Sur., NS-PGL Ex. CMG-3.0, 7:140-143.

Staff witness Ms. Harden offered rebuttal testimony supporting the concept of Mr. Effron's proposal, although not his numbers (Harden Reb., Staff Ex. 24.0 at 18:397 - 21:463), but her testimony does not provide any valid grounds for approving the proposal. She also appears to lack significant training or experience as a sales forecaster, she presented no additional grounds for the proposal, and also overlooked the offsets referenced above. Clabots Sur., NS-PGL Ex. DWC-3.0 at 2:37 - 3:52.

Accordingly, the Commission should reject Mr. Effron's proposal. The proposal lacks any valid basis, is wrong, and it ignores all offsets.

### D. Depreciation (Uncontested Except for Derivative Adjustments from Contested Adjustments)

There are no contested issues relating to depreciation expense as such. The only contested aspects of the expense are the derivative impacts of contested plant adjustments.

### E. Taxes Other Than Income (Payroll and Invested Capital Taxes) (Uncontested Except for Derivative Adjustments from Contested Adjustments)

There are no contested issues relating to taxes other than income taxes as such. The only contested aspects of these taxes are the derivative impacts of certain contested adjustments.

### F. Income Taxes (Including Interest Synchronization) (Uncontested Except for Derivative Adjustments from Contested Adjustment)

There are no contested issues relating to income taxes as such. The only contested aspects here are the derivative impacts of contested adjustments that affect operating income.

## VI. RATE OF RETURN

### A. Overview

#### 1. Overview of the Parties' Positions

Peoples Gas proposes a rate of return on rate base of 9.11% based on a capital structure containing 56% common equity at a cost of 11.87% and 44% long-term debt at a cost of 5.58%. NS-PGL Ex. BAJ-3.1P. North Shore proposes a rate of return on rate base of 9.06% based on a capital structure containing 56% common equity at a cost of 11.87% and 44% long-term debt at a cost of 5.48%. NS-PGL Ex. BAJ-2.1N.

The Utilities' proposed capital structure, which would remain the same as the Commission approved in the Utilities' last rate case, appears to be uncontested. The Utilities and Staff disagree as to one component of long-term debt cost, namely the proper interest rate to assume for Peoples Gas' Series OO auction rate debt that the Utility will refinance in 2010. The Utilities, Staff, and CUB-City disagree as to the Utilities' cost of equity.

The Utilities' proposed rate of return on equity of 11.87% is supported by the updated analysis of their cost of equity witness, Paul Moul. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 7:123 – 8:143. Because the Utilities' stock is not publicly traded, Mr. Moul applied "market" models to a proxy group of natural gas utilities with risk profiles similar to the Utilities, using capital market and financial data that are commonly relied on by investors and analysts to make investment decisions and recommendations. Moul Dir., PGL Ex. PRM-1.0 Rev. at 2:37 – 3:52.

Consistent with the general trend of capital costs in the financial markets, which was discussed in detail by Mr. Steven Fetter, a former chairperson of the Michigan Public Service Commission, Mr. Moul finds that the Utilities' cost of equity has increased since their last rate cases, which were decided just as the financial crisis was beginning to unfold and subsequent economic recession.

By contrast, Staff and CUB-City propose that the Utilities' returns on equity be reduced, and to levels far below what the financial markets would expect. Staff proposes that Peoples Gas' authorized return be reduced by 50 basis points, from 10.19% to 9.69%, and that North Shore's authorized return be reduced by 20 basis points, from 9.99% to 9.79%. McNally Dir., Staff Ex. 7.0 at 21:395-412. For its part, CUB-City recommends a return of equity for each Utility of 8.58% without consideration of riders. Thomas Dir., CUB-City Ex. 2.0 Rev. at 56 (Table 8).

With these recommendations, Staff and CUB-City effectively argue that the Utilities' returns should be reduced to levels below (in CUB-City's case, far below) any other return that this Commission has authorized for an Illinois gas utility since 1972, "notwithstanding the most challenging economic environment experienced during the past 80 years." Fetter Sur., NS-PGL Ex. SMF-2.0 at 9:191-194. The implication – that the Utilities' risk is lower now, in the middle of a deep worldwide economic recession and sharp contractions in the capital market, than it has at any time in the last 30 years – is literally incredible.

### 2. Governing Legal Standards

The legal standards governing a public utility's entitlement to a fair and reasonable return on its investment are well established and familiar. The classic and still-current formulations are those of the United States Supreme Court in the *Bluefield* and *Hope (Federal Power Comm'n v.*

*Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944)) cases. A public utility has a constitutional right to a return that is "reasonably sufficient to assure confidence in the financial soundness of the utility and [is] adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." *Bluefield,* 262 U.S. at 693. The authorized return on equity "should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Hope,* 320 U.S at 603.

Illinois law is consistent. This Commission "is charged by the legislature with setting rates which are '*just and reasonable'* not only to the ratepayers but to the utility and its stockholders." *BPI II,* 146 Ill. 2d at 208-209 (citing 220 ILCS 5/9-201); *see also* 220 ILCS 5/9-101. This Commission "fully embraces the principles set forth" in the *Bluefield* and *Hope* cases. *In re Consumers Ill. Water Co.,* ICC Docket No. 03-0403 at 41 (Order April 13, 2004).

### B. <u>Capital Structure</u> [Combined 1. Peoples Gas and 2. North Shore]

The Utilities propose to maintain capital structures in 2010 at the same levels authorized in their last rate cases: 56% common equity, 44% long-term debt. Johnson Dir., PGL Ex. BAJ-1.0 at 5:91-93.[77] These capital structures appear to be uncontested. *See* Kight-Garlisch Reb., Staff Ex. 22.0 at 4:73-77.

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

### C. <u>Cost of Long-Term Debt</u> [Combined 1. Peoples Gas and 2. North Shore]

The embedded cost of long-term debt in Peoples Gas' proposed cost of capital was 5.96%. PGL Ex. BAJ-1.2. The embedded cost of long-term debt in North Shore's proposed cost of capital was 5.58%. NS Ex. BAJ-1.2.

Staff adjusted the Utilities' proposed costs of long-term debt, primarily to reflect their stand-alone financial strength. Kight-Garlisch Dir., Staff Ex. 8.0 at 13:243 - 21:392. These adjustments resulted in costs of long-term debt for Peoples Gas of 5.27% and North Shore of 5.49%. Staff Ex. 8.1. The Utilities accepted Staff's adjustments to long-term taxable debt. Johnson Reb., NS-PGL Ex. BAJ-2.0 2Rev. at 20:414-420.

Peoples Gas requested two adjustments to Staff-adjusted cost of its insured tax exempt long-term debt. First, Peoples Gas requested that Staff's adjustment to the insurance premium costs associated with Series KK, LL, OO, and RR bonds be halved to reflect the Utility's split credit ratings between S&P and Moody's. *Id.* at 20:402-411. Staff accepted this request. Kight-Garlisch Reb., Staff Ex. 22.0 at 5:82-86.

Second, Peoples Gas objected to Staff's adjustment to the cost of the Series OO auction rate bonds. Before the financial crisis in Fall 2008, these instruments allowed Peoples Gas to issue long-term debt at a price based on short-term rates, with the added benefit of being tax exempt. Johnson Sur., NS-PGL Ex. BAJ-3.0 at 4:65-67. When an auction for these bonds fails, the interest rate is set at 175% of LIBOR up to a cap of 14%. Johnson Reb., NS-PGL Ex. BAJ-2.0 2Rev. at 16:329 – 17:335. Since the crisis, the auction rate securities market has dried up because other investments offer higher yields, and this condition is not likely to change in the foreseeable future. *Id.* at 17:335-340. As another consequence of the crisis, LIBOR

remains at record low levels near zero and the rates that Peoples Gas has paid on these securities has been less than 1% since February 2009. Kight-Garlisch Reb., Staff Ex. 22.0 at 5:89-93.

This situation gives Peoples Gas a short-term benefit in the form of extremely low interest rates, but this benefit carries with it longer-term risks. The holders of most of these securities are three of the Utilities' core credit banks. "[F]orcing these investors … to continue holding this debt in an auction rate mode with a calculated failure rate versus a fair market rate of interest may be detrimental to the Utility in the long-run." Johnson Reb., NS-PGL Ex. BAJ-2.0 2Rev. at 17:352-355. In addition, it is just a matter of time before LIBOR rises again and this will introduce an unacceptable degree of volatility in the cost of these securities due to the 175% multiplier. *Id.* at 18:374 – 19:388; Johnson Sur., NS-PGL Ex. BAJ-3.0 at 3:46-58, 4:74 – 5:91; NS-PGL Ex. BAJ-2.5P. Mr. Fetter agrees that near-zero short-term debt costs "are anomalous and are unlikely to be sustainable whether the U.S. government's stimulus efforts succeed or fail." Fetter Reb., NS-PGL Ex. SMF-1.0 at 14:293-295. When interest rates begin to recover, "auction-rate securities will become uneconomic, and alternative financing options at those low levels will undoubtedly no longer exist." *Id.* at 15:311-315.

For these reasons, "auction rate securities are no longer a viable form of long-term financing" and Peoples Gas will refinance or remarket these securities in 2010. Johnson Sur., NS-PGL Ex. BAJ-3.0 at 5:91-92, 102-103. Thus, Peoples Gas proposes to assume a 1% cost for half the year and a fixed rate debt cost of 7.16% for the rest of the year based on indicative rates. Johnson Reb., NS-PGL Ex. BAJ-2.0 2Rev. at 18:364-365. This would result in an average rate of 4.08% for the cost of these securities over 2010, and an average cost of long-term debit for Peoples Gas of 5.58%. Johnson Sur., NS-PGL Ex. BAJ-3.0 at 5:106-108.

### D. Cost of Short-Term Debt [Combined 1. Peoples Gas and 2. North Shore]

The Utilities do not believe this subject needs to be addressed. *See* Section VI(B), *supra*.

### E. Cost of Common Equity [Combined 1. Peoples Gas and 2. North Shore]

#### 1. Background and Context

Mr. Fetter testified for the Utilities regarding the general context within which the Commission should determine their cost of equity. As a lawyer and former chairman of the Michigan Public Service Commission, and as a former Managing Director of Fitch, Inc.'s Global Power Division, Mr. Fetter draws upon a deep reservoir of knowledge and experience that he continues to build as an advisor to all types of stakeholders in the energy industry, including state public utility commissions and consumer advocates. Fetter Reb., NS-PGL Ex. SMF-1.0, 2:26-29; NS-PGL Ex. SMF-1.1.

Mr. Fetter provided at least 7 key points of context that are critical to this Commission's decisions on the Utilities' authorized returns on equity:

- The financial community viewed the result in the Utilities' last rate case as relatively constructive, but the recent downgrade and assignment of Negative outlooks indicate that the Utilities' relatively strong "A/BBB" split credit ratings are at risk. Fetter Reb., NS-PGL Ex. SMF-1.0 at 12:248 – 13:258.

- Recent returns authorized by others state commissions are at the median 10.50% and average 10.36%. *Id.* at 10:197; Fetter, Tr. 483:16-21.

- A reduction in the Utilities' authorized ROEs in the midst of "the most challenging economic environment during the past 80 years," particularly to the extraordinarily low levels proposed by Staff and CUB-City, would be viewed by the financial markets "as a major setback" and could lead to further downgrades in the Utilities' credit ratings. Fetter Reb., NS-PGL Ex. SMF-1.0 at 12:248 – 13:258; Fetter Sur., NS-PGL Ex. SMF 2.0 at 9:189-194.

- Further downgrades could have harmful financial impacts on the Utilities and their customers, as demonstrated by the unprecedented increase in debt costs for BBB-rated public utilities since the financial crisis in Fall

2008. Not only the spreads between BBB-rated utility debt and Treasuries, but also the spreads between BBB-rated and A-rated utility debt, are at historical highs. Fetter Reb., NS-PGL Ex. SMF-1.0 at 17:358 – 19:383.

- There has been a flight of capital away from more risky investments, as seen by the 13% decline in investment in BBB-rated utilities, while investment in A-rated utilities has increased by a similar margin. *Id.* at 11:219 – 12:231. Lower rated utilities have had to resort to more exotic funding vehicles to secure financing, at higher cost. *Id.* at 14:276-279.

- "It would be poor public policy … to depart from accepted ratemaking approaches used throughout the nation at a time when markets are already unsettled and when the Utilities are sharing recessionary pressures with the entire global utility sector." *Id.* at 9:170-174.

- "In this case, the Commission should authorize a cost of capital that will attract both debt and equity investors to continue to support the Utilities' financing needs." Fetter Sur., NS-PGL Ex. SMF-2.0 at 6:121-123.

Commission precedent supports the consideration of general market conditions and trends because these considerations are central to investor expectations. The Commission has recognized that "a thorough cost of common equity analysis requires both the application of financial models and the analyst's informed judgment. A cost of common equity recommendation based solely on judgment is inappropriate. However, because cost of common equity measurement techniques necessarily employ proxies for investor expectations, judgment is necessary to evaluate the results of such analyses." *In re Aqua Illinois, Inc.,* ICC Docket Nos. 05-0071, 05-0072 (Cons.), at 52-53 (Order Nov. 8, 2005). *See also In re Central Ill. Pub. Serv. Co.,* ICC Docket Nos. 02-0798, 03-0008, 03-0009 (Cons.), at 83-90 (Order Oct. 22, 2003). "In determining what the cost of equity is for a utility, the Commission must base its decision on sound financial principles that are used by sophisticated investors. When determining whether or not to invest in the stock of a particular utility, the sophisticated investor is, in effect, setting the real cost of capital for that utility. The Commission, in authorizing a rate of return, makes an estimate of what the investor is demanding. <u>It is the Commission that reacts to the investor and</u>

not vice versa." *In re Illinois Bell Tel. Co.*, ICC Docket No. 92-0448, 93-0239 (Cons.), at 103 (Order Oct. 11, 1994) (emphasis added). Thus, "the analyst's informed judgment" must be informed by the other types of information upon which sophisticated investors, advisors, and analysts routinely rely, including recent regulatory decisions and market trends.

### 2. The Utilities' Cost of Equity Model Results

Mr. Moul, who calculated and presented the Utilities' proposed cost of equity in these cases, is an independent financial and regulatory consultant with over 30 years' experience in the field. PGL Ex. PRM-1.1.[78] He also calculated and presented the Utilities' cost of equity in their last rate cases. Mr. Moul based his recommendations on three market-based measures of the Utilities' cost of equity using the familiar Discounted Cash Flow model ("DCF"), Capital Asset Pricing Model ("CAPM") and Risk Premium model. Mr. Moul employed three models because no one model provides consistently reliable and accurate results. Moul Dir., Ex. PGL PRM-1.0 Rev. at 13:263-267. Each of the models has its shortcomings, which Mr. Moul discusses in detail in his testimony and exhibits. *Id.* at 14:279-289 (DCF), 29:630-632 (Risk Premium), 35:756-757 (CAPM); PGL Exs. PRM-1.12C, PRM-1.12E, and PRM-1.12F.

Mr. Moul presented results of his analyses in February with his direct testimony, and updated results in July with his rebuttal testimony. His results were as follows:

| Model | February | July |
|---|---|---|
| DCF | 10.58% | 11.41% |
| CAPM | 12.51% | 11.80% |
| Risk Premium | 12.50% | 12.25% |

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

Moul Dir., PGL Ex. PRM-1.0 at 4 (table); Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 7 (table). Mr. Moul weighted his results, assigning 25% weight to his DCF results and 75% to his CAPM and Risk Premium results, which yielded his 11.87% updated recommendation. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 8:140-143.

### 3. Proxy Group Analysis

Because the Utilities' stock is not publicly traded, the models must be applied to a proxy group of publicly traded natural gas utilities with risk profiles similar to the Utilities. Moul Dir., PGL Ex. PRM-1.0 Rev. at 2:44 – 3:49. In this regard, Mr. Moul's analyses are consistent with Section 9-230 of the Illinois Public Utilities Act (220 ILCS 5/9-230), which requires the Commission to determine a public utility's cost of equity without regard to its increased risk resulting from its affiliation with non-utility affiliates.

In assembling his proxy group, Mr. Moul evaluated a broad range of available capital market and financial data on the Utilities and other domestic natural gas utilities over the five-year period 2003-2007. *See* PGL Exs. PRM-1.2, PRM-1.3 and PRM-1.4. This evaluation considered both the operating as well as the financial risk, and included such factors as bond rating, size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and "beta," which is a statistical measure of a stock's relative historical volatility to the rest of the market. Moul Dir., PGL Ex. PRM-1.0 Rev. at 7:146 – 12:242.

Obviously, no individual utility is exactly the same as another, and no proxy group will "look" just like the Utilities. Assembling a proxy group involves a careful evaluation of how differences among the proxy group for the various risk factors offset each other. Mr. Moul evaluated these differences and found that, on balance, his "Gas Group" provided "a

conservative basis for measuring the [Utilities'] cost of equity because many of the risk factors are lower for the Gas Group and, overall, the Gas Group has lower risk than the [Utilities]." *Id.* at 12:244-253 (emphasis added).

The cost of equity experts employed by Staff and CUB-City agreed that Mr. Moul's proxy group provided a reasonable basis on which to base the application of the market models. Mr. McNally for Staff testified that "Mr. Moul's sample companies provide reasonable proxies for the operating risk of North Shore and Peoples Gas." McNally Dir., Staff Ex. 7.0 at 3:43-44. Mr. Thomas for CUB-City also used the Utilities' proxy group for his analyses. Thomas Dir., CUB-City Ex. 2.0 Rev. at 12:257-264. Yet, as discussed in Section VI(E)(5)(a), *infra*, Mr. McNally asserts that he is free to adjust his results for differences he finds between Gas Group and the Utilities in "financial risk." McNally Dir., Staff Ex. 7.0 at 22:413 – 28:533.

#### 4. DCF Results

##### a. The Utilities' DCF Analysis

The DCF model expresses the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return, which for common stock is the dividend yield plus future price growth. Moul Dir., PGL Ex. PRM-1.0 Rev. at 13:275 – 14:278. Mr. Moul employed a "constant growth" version of the DCF model, meaning that he assumed one rate of future price growth instead of multiple rates, or "non-constant" growth, that change over time.

For the dividend yield, Mr. Moul calculated the six-month average dividend yield of the Gas Group, adjusting the average by three generally accepted methods to reflect investor-expected cash flows, and then averaging the three adjusted values. *Id.* at 14:291 – 15:312; PGL Exs. PRM-1.5, PRM-1.12C. Mr. Moul originally calculated a dividend yield of

4.03%, but also found that the yield increased by some 64 points between February and July. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 7:132-133.

For the investor-expected growth rate, Mr. Moul evaluated a broad array of historical and forecast growth data from widely-available sources that are routinely relied on by investors and analysts. *See* Moul Dir., PGL Ex. PRM-1.0 Rev. at 17:358 – 18:377; PGL Exs. PRM 1.6 (historical), PRM 1.7 (forecast). He focused on five-year forecasts of earnings per share growth because empirical evidence supports it and these data are the most relevant data to investors' total return expectations. Moul Dir., PGL Ex. PRM 1.0 Rev. at 18:380 – 19: 397; 20:414-417. Considering all of the forecasts of earnings per share growth that are available to investors, Mr. Moul selected 6.00% as a mid-point value. *Id.* at 20:421 – 21:436.

**b. <u>Financial Leverage</u>**

Mr. Moul's "raw" DCF result is based on the <u>market</u> price of the stock of the Gas Group, which reflects the financial risk associated with the Gas Group's average capital structure at its <u>market</u> value. Moul Dir., PGL Ex. PRM-1.0 Rev. at 21:444-445. If, however, the market-based DCF result is to be applied to a capital structure that is valued on a basis other than market, the DCF result must be adjusted (up or down) to reflect the difference in financial risk reflected by the non-market value capital structure. *Id.* at 21:445-449.

Here, the DCF result that reflects the market value of the Gas Group's stock is to be applied to the Utilities' capital structure at its <u>book</u> value. The market valuation of the Gas Group's capitalization is higher than its book valuation. At market value, the Gas Group's equity ratio is 69.30%, compared to 56.00% at book value. The Gas Group's stock price, and therefore the DCF result, reflects the lower financial risk associated with the higher equity ratio. The DCF result does not reflect the higher financial risk associated with the Gas Group's lower

book value equity ratio. Applying a market-based DCF result to a book value capital structure is a mismatch. If the market-based DCF result was set as the Utilities' authorized return and was applied to their book value capital structures, then all other things equal the Utilities would not be able to earn the authorized return. *See generally,* Moul Dir., PGL Ex. PRM-1.0 at 21:444-451, 26:567 – 27:583.

This is shown by the simplified example provided by Mr. McNally in his rebuttal testimony. Staff Ex. 21.0 at 21:468 – 22:481. He posited a firm that issues $100 of common equity. The "required return" on that investment is 10%, but investors expect that that the firm will earn 11%. Mr. McNally's argues that if the market bids the firm's stock above book value to $110, the market return is still 10%, i.e., $11 on $110. But Mr. McNally misses the key point. If regulation limits the firm's return to 10% on its <u>book value</u> equity, then the $11 expected return will not be earned. Moul Sur., NS-PGL Ex. PRM-3.0 Rev. at 8:178-187. Rather, in Mr. McNally's example, the firm will earn only $10 on its $110 of market value equity, or 9.1%. In order for the investor to earn her expected return of $11, either the market return (10%) must be applied to the firm's market value equity, or the market return must be adjusted (here, from 10% to 11%) before it is applied to the firm's book value equity.

In order to develop such an adjustment in this case, Mr. Moul employed formulas developed by Nobel laureates Modigliani and Miller to measure the increase in the return on equity associated with increases in financial risk from the lower equity ratios in a utility's book value capital structure. He first calculated the Gas Group's return on equity based on an equity ratio of 100%, which is 9.30%. He then added 1.27% compensation for having 43.79% debt and 0.01% for having 0.21% preferred stock in the Gas Group's actual capital structure. The result – 10.58% - was 55 basis points higher than his unadjusted DCF result. Moul Dir., PGL Ex. PRM

1.0 Rev. at 23:483-505. Hence, the 55-basis point "financial leverage adjustment" that Mr. Moul later updated to 74 basis points. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 7:132 – 8:134. Mr. Moul's adjusted DCF result is therefore 11.41%. This return "is the one that is necessary for the utility to earn on its book value capital structure in order to earn the return that is based on the market value capital structure." Moul Dir., PGL Ex. PRM-1.0 Rev. at 25:534-536.

Mr. Moul acknowledged that the Commission rejected his financial leverage adjustment in the Utilities' last rate cases. Order at 84-85, ICC Dockets 07-0241/07-242/Cons. (Feb. 5, 2008). The Commission's decision was based on the misconception, repeated by Staff and CUB-City in these cases, that Mr. Moul's financial leverage adjustment is intended to maintain a particular market-to-book ratio of the Utilities' equity value. Although the Commission has rejected market-to-book ratio adjustments in the past, Mr. Moul's financial leverage adjustment is not such an adjustment. The market-to-book ratio plays no role in the adjustment, nor does the adjustment Mr. Moul proposes have the effect of maintaining any particular market-to-book ratio. Moul Dir., PGL Ex. PRM-1.0 at 25:539-547.

#### c. Staff's Recent Conversion to the Non-Constant Growth DCF Model

As noted above, Mr. Moul utilized a "constant growth" version of the DCF model. In this respect, his approach was consistent with Staff's DCF analysis in the Utilities' last rate cases. It is also consistent with the Commission's acceptance of the Utilities' unadjusted constant growth DCF model as one of the analyses that formed "an appropriate basis to determine ROE" in those cases. *Peoples 2007* at 100.

Since those cases, Staff has apparently switched to a "non-constant growth" version of the DCF model. Although Mr. McNally argued that he did so in these cases because "the level of growth indicated by the average 3-5 year growth rate for the Gas Group is not sustainable over

the long-term" (McNally Dir., Staff Ex. 7.0 at 4:84 – 5:86), Staff appears to have uniformly applied the non-constant growth model in every gas and electric rate case since the Utilities' last cases. *E.g., In re Commonwealth Edison Co.,* ICC Docket No. 07-0566, at 80 (Order Sept. 10, 2008); *In re Central Illinois Light Co. d/b/a AmerenCILCO, et al.,* ICC Docket Nos. 07-0585, *et al*., Cons. at 182 (Order Sept. 24, 2008); *Nicor 2008* at 56; *In re Illinois Gas Co.,* ICC Docket No. 08-0482, at 16 (Order May 13, 2009). Thus, this appears to have been a basic methodological change.

The theory behind the non-constant growth version of the model is that a firm initially experiences

> rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure…. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of the firm. <u>The three stages of growth assume a step-down of high initial growth to lower sustainable growth</u>.

Moul Dir., PGL Ex. PRM-1.0 Rev. at 16:334-344 (emphasis added). The non-constant growth version of the DCF model hardly seems appropriate for application to Utilities that have been in the same regulated business for many decades. Moreover, the assumption that the "steady state" growth stage will remain fixed in perpetuity is unrealistic because the three stages of growth can be repeated. *Id.* at 16:345-347.

Apparently Staff believes the constant growth form of the DCF is only valid when growth rate forecasts for gas utilities are equal to or less than the long-term overall growth in the economy represented by GDP growth. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 15:312-314. When, as now, growth rates for gas utilities are higher than GDP growth – which is perhaps explained by potential productivity and rate base growth in the gas utility sector (*id.* at

19:382-395) – Staff has switched to the non-constant growth form of the model. Staff argues it must be this way because if a growth rate higher than GDP growth is used in the constant growth DCF model, it assumes that unrealistic scenario that the firm will eventually grow to equal the entire economy. McNally Dir., Staff Ex. 7.0 at 5:92-94; McNally Reb., Staff Ex. 21.0 at 8:178 – 9:210. This "wholly unrealistic scenario" of a utility growing faster than the overall economy may be interesting, but it is irrelevant to actual investors, who typically view investment decisions on a horizon of no more than five years and do not care about a firm's growth compared to GDP growth into the infinite future. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 15:314-317. The constant growth DCF model is more reflective of actual investor expectations.

The academics cited by Mr. McNally in support of the non-constant growth form of the model are concerned about applications of the constant growth form to firms with extraordinary growth rates, not necessarily above-average growth rates. Moul Sur., NS-PGL Ex. PRM-3.0 Rev. at 5:107-109. For example, Professors Brealey, Myers and Allen, cited by Mr. McNally at pages 9-10 of his rebuttal testimony, use the example of the railroad industry in 2005 and 2006, a period in which the railroads "were expanding rapidly … as they were recovering from a period of low profitability." RICHARD A. BREALEY, STEWARD C. MYERS AND FRANKLIN ALLEN, *Principles of Corporate Finance* at 95 (9th Ed. 2008) ("BREALEY"). Analysts were forecasting growth of 12-15% for these companies. Professors Brealey, et al. recommend use of the non-constant growth DCF when firms are growing at extraordinarily high rates due to unusual profitability or recovery from a period of low profitability. *Id.* at 97. Mr. McNally has made no showing that the Gas Group is experiencing extraordinary growth rates for either reason.

The Federal Energy Regulatory Commission ("FERC") has developed objective criteria for when to use each form of the DCF model. *Southern California Edison Co.,* 92 FERC

¶ 61,070 (2000). These criteria include whether analyst growth forecasts are two or more times GDP growth, in which case FERC applies the non-constant growth form. This is certainly untrue for the Gas Group, the average investor-expected growth rate of which is about 6.00% according to Mr. Moul, as compared to Mr. McNally's 4.59% estimate of long-term GDP growth. Moul Dir., PGL Ex. PRM-1.0 at 20:430-434; McNally Dir., Staff Ex. 7.0 at 6:127 – 7:136. By these criteria, the constant growth form of the DCF model should be used to determine the cost of equity for natural gas utilities in general and the Utilities in specific. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 18:362 – 19:381.[79]

The impact of applying the non-constant growth form of the model is that it results in lower returns due to the step-down of the growth rate over the assumed "stages" of growth. The impact in these cases is dramatic, and would have been foreseen by Staff before it switched to the non-constant growth form of the model. With the decline in stock prices, increase in dividend yields and increase in growth rates among the Gas Group, the constant growth DCF model will result in higher cost of equity results. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 20:398 – 23:447. Indeed, had Staff used the same DCF model that it used in the Utilities' last rate cases, the unadjusted result would have been 11.76%, over 100 basis points higher than Mr. Moul's unadjusted result. *Id.* at 23 (table). Instead, by using the non-constant growth form and assuming lower growth in the future than in current forecasts, indeed down to GDP growth after 10 years, Staff got its DCF result down to 10.23%, which is still 200 basis points higher than Staff's constant growth DCF result in the Utilities' last rate cases. *Id.* at 22 (table). For these

[79] Mr. Thomas claims that gas distribution companies have similar characteristics as interstate gas pipeline companies and therefore the non-constant growth form remains appropriate here. Thomas Reb., CUB-City Ex. 4.0 at 11:234-247. However, Mr. Thomas presented no analysis of FERC's criteria to support his assertion that gas distribution companies have greater "stability" than the pipelines. Mr. Moul has applied the FERC criteria against the characteristics of gas distribution companies and found that "the two-stage DCF would not apply to them because they have characteristics more like electric utilities." Moul Sur., NS-PGL Ex. PRM-3.0 Rev. at 13:291-292. Mr. Thomas' claim has no foundation and should be rejected.

reasons, Mr. Moul concluded that the primary if not exclusive reason for Staff to switch to the non-constant form of the model was "subjective and result-oriented, namely to arrive at reduced costs of equity in utility rate cases." *Id.* at 16:318-320.

If objective criteria are used to determine which form of the DCF model to use, the constant growth form wins hands down. Staff's contrary position reflects its subjective judgment as to the growth in earnings an investor should expect instead of what the investor actually requires. As Mr. Moul explained, GDP is not an appropriate measure of a natural gas utility's long-term growth. This is because the GDP is comprised of many elements, some are relevant to a natural gas utility's growth but many others are not. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 17:339-354. In other words, some GDP components have higher growth rates than the overall GDP because other GDP components have lower growth rates than overall GDP. "The important point is not whether a company has an above-average growth rate, but whether the growth rate to be used in the DCF model is within a reasonable range that can be viewed as sustainable." Moul Sur., NS-PGL Ex. PRM-3.0 Rev. at 5:103-105.

Obviously, the corporate profits component of the GDP is highly relevant to the Utilities. According to *Blue Chip*, corporate profits are forecast to grow on average 7.0% in the period 2011-2015 and 5.5% during the period 2016-2020. Both rates are higher than the overall GDP growth rate assumed by Mr. McNally of 4.59%. Had Mr. McNally used a 5.5% growth rate in his non-constant growth DCF model, the result would have been 10.88%. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 17:355 – 18:361. "There is no justification for arbitrarily imposing a rigid cap on growth as proposed by Mr. McNally when he has not shown that the analysts' growth forecasts are unreasonable." Moul Sur., NS-PGL Ex. PRM-3.0 Rev. at 5:114-116.

In addition, Mr. McNally failed to support his choice of "the implied 20-year forward U.S. Treasury rate in ten years" for infinite GDP growth. He failed to show how that Treasury rate related to any of the components that make up GDP growth, much less any relationship between the rate and the overall GDP. *Id.* at 6:135-140. "Mr. McNally is merely guessing at a critical input in his non-constant DCF model." *Id.* at 7:141.

The Commission should reject Staff's non-constant growth DCF model.

#### d. DCF Conclusion

The Utilities' updated constant growth DCF result is 10.67% unadjusted and 11.41% adjusted.

### 5. CAPM Results

The CAPM determines an expected rate of return on a security by adding to the "risk-free" rate of return a risk premium that is proportional to the non-diversifiable, or systematic, risk of the security. PGL Ex. PRM-1.12F at 1:917-919. This model requires three inputs: (1) the risk-free rate of return, (2) a "beta" that measures systematic risk, and (3) the market risk premium derived from the total return on the market for equities minus the risk-free rate of return. Moul Dir., PGL Ex. PRM-1.0 Rev. at 36:765-768.

For the risk-free rate of return, Mr. Moul reviewed historical and forecast yields on 20-year Treasury bonds. *See* PGL Exs. PRM-1.10, PRM-1.12D. Based on this range of yields, Mr. Moul selected a mid-point of 4.25% based primarily on recent historical trends and current forecasts. Moul Dir., PGL Ex. PRM-1.0 Rev. at 37:803 – 38:819.

For the beta, Mr. Moul relied on those published by *Value Line*, which averaged 0.69 for the Gas Group. *Id.* at 36:779-780. Mr. Thomas claims that betas from additional sources should also be considered, and CUB-City will apparently argue that Mr. Moul's reliance on only *Value*

*Line* betas was unreasonably subjective. Thomas Dir., CUB-City Ex. 2.0 Rev. at 37:917-920. But as Mr. Moul explained at the hearing, *Value Line* is the only beta source that publishes its methodology. Moul, Tr. 449:18 – 453:6, 465:4-18. He has evaluated *Value Line*'s methodology and found it reasonable and well accepted in the investment community. Moul, Tr. 466:11-21. In his investigations, Mr. Moul has not been able to confirm the methods, data sources, or reliability of other sources like *Yahoo!* and *Reuters*. Moul, Tr. 461:6 – 464:4. Mr. Moul's reliance on *Value Line* betas for his CAPM analyses is perfectly reasonable.

For the market premium, Mr. Moul averaged forecast data from *Value Line* and the S&P 500 Composite, and historical data from Ibbotson Associates, all of which are widely used by investors, analysts and academics. The result was 8.95%. Moul Dir., PGL Ex. PRM-1.0 Rev. at 38:821 – 40:849.

When he updated his results in July, Mr. Moul found that the risk-free rate remain unchanged, the beta declined by 4 basis points, and the market premium declined by 47 basis points, yielding an updated unadjusted CAPM result of 10.86% before the size adjustment that applied to the Gas Group.

**a. Financial Leverage Adjustment**

For the same reasons as the similar adjustment to his DCF result, Mr. Moul adjusted his CAPM beta to account for the fact that the *Value Line* betas are market-based but must be applied to the Utilities' book value capital structures. Mr. Moul did so by "unleveraged" the market-based betas and "releveraged" them for book value common equity ratios using the "Hamada" formula. *Id.* at 36:782 – 37:799. The result increased the average beta for the Gas Group from 0.69 to 0.82, which translates to an adjustment of 116 basis points (.82 - .69 = .13 x 8.95% = 1.16%). *Id.* at 37:800-801.

### b. Size Adjustment

Mr. Moul also adjusted his CAPM result for the relatively small size of the Gas Group compared to the market. This adjustment is unique to the CAPM because it can significantly understate the cost of equity of smaller companies, including utilities. *Id.* at 40:852-863. Even though the utilities in the Gas Group qualify as "low-cap" portfolio companies, Mr. Moul limited his size adjustment to that for "mid-cap" companies. *Id.* at 40:863 – 41:868. This adjustment increased slightly as the result Mr. Moul's update, to 94 basis points. Moul Reb., NS-PGL Ex. 2.0 Rev. at 8:138-139.

Mr. McNally challenged Mr. Moul's size adjustment, asserting that it "has no theoretical basis." McNally Dir., Staff Ex. 7.0 at 43:863. Mr. McNally is mistaken. The financial literature supports the general rule established by Fama and French that the smaller the firm, the larger its risk and required return. Moul Dir., PGL Ex. PRM-1.0 Rev. at 40:852 – 863; *see also* BREALEY, at 225-227. That makes common sense because a larger firm enjoys both a greater financial cushion against shocks and a greater ability to diversify, including over time. By contrast, Mr. McNally cited a single article for the proposition that this rule does not apply to utilities. McNally Dir., Staff Ex. 7.0 at 44:893 – 45:896. Mr. Moul demonstrated that this article's focus on the CAPM beta does not address the question of additional risk for smaller sized firms that are not captured by the CAPM model. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 39:782-798.

### c. CAPM Conclusion

The Utilities' updated unadjusted CAPM result is 10.86.%. The Utilities' updated adjusted CAPM result is 11.80%.

### 6. Risk Premium Result

The Risk Premium model measures the cost of equity by determining the degree to which equity has more risk than corporate debt, and adding that "equity risk premium" to the interest rate on long-term public debt. Moul Dir., PGL Ex. PRM-1.0 at 29:628-630. Mr. Moul estimated a 7.00% prospective yield on long-term A-rated utility bonds, based on a thorough evaluation of both historical yields and *Blue Chip* forecasts, taking into consideration the extraordinary impact of the spread in yields between A-rated utility bonds and long-term Treasury bonds resulting from the financial crisis. Moul Dir., PGL Ex. PRM-1.0 Rev. at 29:634 – 32:693; PGL Ex. PRM-1.8. This yield declined to 6.75% as the result of Mr. Moul's July update. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 8:134-136. For an equity risk premium, Mr. Moul reviewed historical returns for utilities in the S&P Public Utility Index over three separate historical periods tied to specific benchmark events. Moul Dir., PGL Ex. PRM-1.0 Rev. at 32:695 - 34:730. Based on this review, Mr. Moul determined that 6.23% represented a reasonable equity risk premium for the S&P Public Utility index. Taking into account the difference in the composition of that index and Mr. Moul's Gas Group, he established a 5.50% risk premium which reflected his consideration of size, market ratios, common equity, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds and betas. *Id.* at 34:732 – 35:748.

The Utilities' updated Risk Premium result is 12.25%.

### 7. Use of Historical Data

As discussed above, Mr. Moul considered historical as well as current forecast data in setting various of his inputs to the financial market models In each case, he relied on published sources of information that are widely available to, and routinely consulted by, investors and

analysts. These are the data relied upon by those who ultimately determine the cost of equity in the real world.

As it did in the Utilities' last rate cases, Staff criticizes Mr. Moul's use of historical data in his analyses. Mr. McNally characterizes such data as "outdated" and no longer relevant to the market. McNally Dir., Staff Ex. 7.0 at 37:728-730. Mr. McNally says that using historical data "implies that securities data will revert to a mean," which is an inappropriate measure for the "random walk" of returns. *Id.* at 37:730-739. The irony of Staff's criticism is that it has little to do with Mr. Moul's analysis and everything to do with Staff's.

Mr. McNally's criticism of Mr. Moul is based on a mischaracterization of his analysis. From Mr. McNally, one would get the impression that Mr. Moul simply plugged historical data into his models without giving it a second thought. Mr. McNally goes so far to charge Mr. Moul of "the mechanistic use of historical data as a direct estimate of the investor expectations that are embedded in cost of common equity estimates." McNally Reb., Staff Ex. 21.0 at 2:29-31. That is not true.

In each case that Mr. Moul used historical data, he evaluated that information in conjunction with current and forecast data and other considerations, such as the type of information investors, analysts and academics actually rely on. These, of course, are considerations that Mr. McNally completely ignored in his own analyses. Even to investors who are full believers in the "random walk" theory, that walk does not occur in the absence of context. For example, no one believes that companies with very different risks and performance records will "walk the same path" even if their weavings on their particular path are best measured by current and forecast data. Historical data is also a valuable means of checking predicted model results. Models that produce what are actually unrealistic results are not to be

credited and nothing in the "random walk" theory suggests otherwise. Mr. Moul's analysis recognizes the appropriate uses of historical data in just these contexts. His "use of historical data in the financial models provides an objective basis to observe trends and relationships between variables." Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 9:176-177.

Accordingly, Mr. Moul developed his DCF dividend yield by starting with the six-month average dividend yield of the Gas Group and adjusting it using generally accepted methods to reflect the investor's expected cash flows. Mr. Moul's CAPM equity risk premium is an average of values from *Ibbotson* historical data and *Value Line* forecast data. For the long-term debt rate in his Risk Premium model, Mr. Moul picked a value based on his review of both historical bond yields as well as *Blue Chip* forecasts. Only for the equity risk premium component of his Risk Premium model did Mr. Moul rely solely on historical data, but even there Mr. Moul reviewed a wide range of data to discern the more recent historical trend. He did not, as Mr. McNally claims, use the historical data arbitrarily.

By contrast, Mr. McNally's DCF model relies in large part on the stock prices for the Gas Group. He did not review any historical or forecast data on such prices, or any other contextual information, but rather based his analysis solely on the "spot" stock prices of each Gas Group member on a single day: May 14, 2009. McNally Dir., Staff Ex. 7.0 at 8:153-168. Although Mr. McNally characterizes these prices as "current," they are no less historical than the data Mr. Moul considered, if by historical data we mean information from the past. Moul Sur., NS-PGL Ex. PRM-3.0 Rev. at 2:33-35.[80] Indeed, many of Mr. McNally's criticisms of Mr. Moul actually apply to Mr. McNally's blind reliance on stock prices now over four months old:

[80] Mr. McNally also chose to rely on historical data stretching back 5 years to develop his CAPM beta. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 9:174-175, 14:276-277.

- "Using a [four-month old] stock price along with current growth expectations … will likely produce an inaccurate estimate of the market-required rate of return on equity." McNally Dir., Staff Ex. 7.0 at 8:165-168.

- Four-month old stock prices constitute "outdated information that the market no longer considers relevant over the most-recently available information." *Id.* at 37:728-730.

- Four-month old stock prices reflect "conditions that may not continue in the future." *Id.* at 37:730-731.

- Four-month old stock prices "must include observations that cannot reflect the most current information available to the market." *Id.* at 38:749-750 (emphasis in original).

- "[O]ne need not rely on out-dated stock prices … to conduct DCF … analyses." McNally Reb., Staff Ex. 21.0 at 3:64-65.

- "Every day new information becomes available and investors rethink their projections of future cash flows, the risk level of the company, and the price of risk." *Id.* at 4:82-84.

According to Mr. McNally, he selected the date of May 14th "for one reason only: to provide the most recently available information possible while still allowing me enough time to complete my analysis and testimony by the June 10th deadline." McNally Reb., Staff Ex. 21.0 at 5:94-96. Mr. McNally apparently did not give any consideration to the representativeness of the stock prices on that given day in light of the types of historical and forecast information available to and relied upon by investors and analysts. Even a believer in a random walk recognizes that, from day to day, markets are moved by short-term events that no one expects will have lasting impact. After all, stock prices on any given day can be skewed by extraordinary events or conditions on that day, making them anomalous. According to Mr. Moul, "there is evidence to suggest that short-term inefficiencies can exist in stock prices, and those effects can be magnified when only a spot price is considered in the DCF return." Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 10:197-199. Mr. McNally conceded that "stock prices can be influenced by imbalances

in supply and demand." McNally Dir., Staff Ex. 7.0 at 39:762. Even the academic literature cited by Mr. McNally clearly refutes his position that spot stock prices are a superior basis for determining the cost of equity: "Estimating expected return is hard. Daily data hardly help at all." McNally Reb., Staff Ex. 21.0 at 3:42 (quoting Fischer Black, *Estimating Expected Return*, Financial Analysts Journal, Jan.-Feb. 1995, at p.168) (emphasis added).

To put it bluntly, basing an ROE recommendation on spot data from a randomly selected day, with no check for representativeness or context, is arbitrary. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 10:200 – 11:206. Staff's position is necessarily inconsistent, because it calls on the Commission to act on data that is months old, and according to Staff's view, all but meaningless. It is a better approach to consider both historical data – not because performance reverts to a mean, but because it can put current data in context – as well as investors' forecasts of what will occur in the relevant time period. "The use of historical data assists the analyst to identify longer-term trends that may provide a more accurate view of the future than a single day 'snapshot' that by definition is outdated the very next day." *Id.* at 10:188-191.

Nonetheless, the Utilities acknowledge that the Commission has accepted "snapshot" recommendations in many rate cases. At the very least, the Commission should give additional consideration to return analyses that are based on a broader array of relevant data such as those presented by Mr. Moul. This would be consistent with Commission's approach in the Utilities' last rate cases, in which the Commission based its return decision on Mr. Moul's DCF and CAPM models (which were based on his "use" of historical data to the same extent as his same models in these cases) and Staff's CAPM model. *Peoples 2007* at 100. In other words, the Commission should make it clear that financial models that rely in part on relevant historical information can form the basis for the authorized return. Mr. Moul's analyses, which included

but were not limited to consideration of historical data in conjunction with current and forecast data, and use of data from sources that are widely available to and relied upon by investors, analysts and academics, certainly should qualify for the Commission's consideration.

### 8. Staff's "Financial Risk" Adjustment

The Utilities continue to oppose this adjustment, which is based on Staff's contradictory positions that the Gas Group accurately reflects the Utilities' "operational risk" and provides an appropriate basis for running the cost of equity models, but does not accurately reflect the Utilities' "financial risk" as reflected in their current credit ratings. Staff's methodology is fatally flawed.

Staff's financial risk adjustment is designed to reduce the cost of equity in most cases. This is because Staff develops hypothetical credit ratings based on the assumption that the utility will earn its full revenue requirements in the test year (as calculated by Staff). *See* McNally Dir., Staff Ex. 7.0 at 22:435 – 23:446 (describing ratios that result from Staff's revenue requirement recommendations). This assumption of full recovery is contrary to the actual result of a rate case, that the utility will only have an opportunity to recover. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 31:618-622. One need only look to the Utilities' actual earnings since their last rate cases to judge the reasonableness of Staff's assumption of full revenue requirement recovery. Staff's methodology therefore ignores the risks to the utility's ability to recover the authorized revenue requirement.

Staff then compares its overly optimistic hypothetical credit ratings for the utility to the actual credit ratings of the proxy group, which are based on achieved performance over a historical period, in this case 2005-2007. Recall that this is the same Staff that rigidly rejects the use of historical data in the cost of equity models because such data is "outdated" and can only

result in "inaccurate" results. *See supra* Section VI(E)(4)(b). In any event, this is a wholly illogical and arbitrary "apples and oranges" comparison. As Mr. Moul cogently explained,

> It is inappropriate to compare the future opportunity provided to the Utilities in a rate case with the past achieved results for the Gas Group. One need look no further than the Utilities' actual performance under their rates approved less than two years ago. According to the Utilities' ROE reports for 2008, to date they have not earned anywhere close to their authorized returns as shown by their earned returns of 5.64% for Peoples Gas as compared to the 10.19% opportunity provided to the Company in the Commission's order. The comparison for North Shore is 6.66% achieved vs. 9.99% opportunity provided in the Commission order. Based on these data, the financial risk adjustments that Staff proposed [and the Commission adopted] in the Utilities' last rate case grossly overstated their financial performance and understated their financial risk.

Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 32:624-633 (emphases added). The Commission will look in vain for any response by Staff to this fundamental failing of its financial risk adjustment.

Even if Staff's methodology was sound, the Commission should reject Staff's proposed adjustments in this case. By focusing only on credit ratings and other financial risk factors, Mr. McNally ignored offsetting risks of the Gas Group that make it overall comparable in risk to the Utilities. Mr. Moul used as example Peoples Gas' substantially higher earnings variability and IGF to construction ratios than those of the Gas Group. According to Mr. Moul, by these factors Peoples Gas has more risk than the Gas Group, by an amount that could easily justify a 30-basis-point increase in authorized return. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 30:586-591. For these reasons, Mr. Moul concluded as follows as to the overall risk of the Utilities and Gas Group: "On balance, the cost of equity developed from the Gas Group provides a conservative basis for measuring the [Utilities'] cost of equity because many of the risk factors are lower for the Gas Group and, overall, the Gas Group has lower risk than the [Utilities]." Moul Dir., PGL Ex. PRM-1.0 Rev. at 12:250-253 (emphases added).

Mr. McNally made a late attempt to challenge Mr. Moul's "overall" risk analysis due to the refunds the Utilities were ordered to pay in 2006 and 2007, which Mr. McNally claimed

distorted the business risk ratios that Mr. Moul relied on. McNally Reb., Staff Ex. 21.0 at 24:527-539. However, Mr. Moul demonstrated that Mr. McNally overstated the net income impact of those refunds, and that the actual impact was relatively small as measured by the coefficients of variation of the actual returns. Moul Sur., NS-PGL Ex. 3.0 at 9:204 – 10:214. Therefore, the fact of these refunds did not change Mr. Moul's conclusion "that the Utilities have higher business risk than the Gas Group, which offsets the lower financial risk that Mr. McNally has identified. Hence, no financial risk adjustment is warranted for the Utilities in this case." *Id.* at 10:214-216.

Finally, the record does not support Mr. McNally's assertion that the credit rating agencies' recent downgrades of the Utilities were due exclusively to the risk profile of their corporate parent. To the contrary, Moody's focuses on rating companies on a stand-alone basis and has stated that the Utilities' current (post-downgrade) ratings reflect the Utilities' financial strength relative to their peers. Moody's has warned that a decline in the Utilities' financial metrics for an extended period could lead to another downgrade. Fetter Reb., NS-PGL Ex. SMF-1.0 at 13:254-258. Moreover, "even under S&P's consolidated methodology, the Utilities have limited the financial impact of the holding company affiliation by issuing all of [their] long-term debt as first mortgage bonds. The upward notching of such senior secured debt (two notches for North Shore up to 'A' and one notch for Peoples Gas up to 'A-') substantially reduces credit rating effects and financing cost drag due to the parent holding company's unregulated activities." *Id.* at 17:348-354. Mr. McNally's financial risk adjustment took none of this into account and instead simply assumes that the downgrades and the Utilities' current credit rating "suppression" are due solely to their relationship with the unregulated activities of

Integrys Energy Group, Inc. Obviously, they are not, and therefore the hypothetical "stand-alone" credit ratings that he creates for the Utilities are overstated.

In short, the financial risk adjustments to the Utilities' authorized returns in their last rate cases were punitive, just as the analogous adjustments will be here if they are adopted again. The Commission should avoid similar punitive treatment in these cases by rejecting Staff's proposed financial risk adjustments, and should take this opportunity to disavow the Staff financial risk adjustment methodology.

### 9. Adjustments for Riders VBA and ICR

In the Utilities' last rate cases, the Commission reduced their authorized returns by 10 basis points to reflect its approval of a decoupling rider. The Commission rejected the Utilities' argument that the adjustment was unnecessary because most of the gas companies in the Gas Group had some form of revenue stabilization mechanism in place. The Commission rejected that argument, ruling that "the record contains no quantitative evidence for comparison and no comparative analysis of the operational characteristics of the various mechanisms and Rider VBA." *Peoples 2007*, at 98. Plus, the Staff's analysis that supported the adjustment gave no consideration whatsoever to whether Gas Group companies had decoupling mechanisms. Moul Sur., NS-PGL Ex. PRM-3.0 Rev. at 11:238-242.

Therefore, the Commission gave no consideration to whether or to what extent the Gas Group's risk reflected the impact of revenue stabilization mechanisms. In other words, the Rider VBA adjustment "was designed to accommodate the perceived change in risk when the Utilities adopted Rider VBA." Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 32:638-640 (emphasis in original). Now that Rider VBA has been in place in two years, there is no need for the adjustment because there is no additional change in the Utilities' risk. *Id.* at 32:640-642.

In these cases, Staff concedes that most of the companies in the Gas Group have revenue stabilization mechanisms in place. Staff claims that "the relatively small size of the Rider VBA adjustment is consistent with the fact that most, but not all, of the companies in the Gas Group have in place some sort of de-coupling rider applicable to at least a portion of their service territories." McNally Reb., Staff Ex. 21.0 at 27:602-605. This revisionist interpretation of the Commission's decision in the Utilities' rate cases finds no basis in the record or final order, and the Commission should reject it out of hand. Indeed, Staff's concession that most of the Gas Group companies have revenue stabilization mechanisms underscores the lack of any foundation for the Rider VBA adjustment in these cases.

Staff's proposal for a 163 basis point adjustment to the ROE factor of Rider ICR is grossly overstated. As noted above, in the Utilities' last rate cases, the Commission reduced the Utilities' authorized returns by 10 basis points to reflect their institution of Rider VBA. This rider, for a pilot period, provides for recovery of the applicable portion of Peoples Gas' margin revenues from S.C. Nos. 1 and 2 customers, which is estimated to be about $274 million in 2010. Staff Ex. 15.0, Att. H**.** By contrast, Rider ICR would cover only the return on and of additional investments in replacement gas main. Even if Peoples Gas took full advantage of the rider up to the proposed 5% rate base revenue cap, the total revenue covered would be about $30 million. PGL Ex. VG-1.14 Rev. Therefore, if the adoption of Rider VBA affected the Utilities' cost of equity by 10 basis points, the effect of Rider ICR, if any, would be much smaller. Moul Reb., NS-PGL Ex. PRM-2.0 Rev. at 33:648-650.

The Commission should reject Staff's proposed Rider ICR adjustment for three additional reasons. First, Mr. McNally claims that the rider "effectively eliminates the risk that prudent and reasonable project costs will not be recovered." *Id.* at 34:674-676 (emphasis added).

This may be true, but Peoples Gas remains at risk for non-recovery if the Commission determines that project costs are not prudent or reasonable. As Mr. Fetter explained at the hearing, the Commission should not confuse the penalties for imprudence, which include but are not limited to non-recovery, to the operational risks that are inherent in a natural gas utility and that must be reflected in its cost of capital. Fetter, Tr. 498:11 – 499:3, 506:5 – 508:6.

Second, Mr. McNally failed to demonstrate through any cash flow or other analysis the appropriateness of adjusting Peoples Gas' authorized return on equity by one-half the spread between his recommended cost of equity and the yield on AAA-rated, 30-year utility bonds. McNally Dir., Staff Ex. 7.0 at 35:689 – 36:706. As noted above, even if implemented to its maximum extent Rider ICR affects a relatively small portion of Peoples Gas' total revenue requirement.

Third, Mr. McNally's proposed adjustment assumes that Peoples Gas would necessarily implement accelerated main replacement to the maximum extent provided in the rider. This assumption is not supported by the record. *See* Schott, Tr. 60:21 – 61:15. Although Staff has taken the position that Peoples Gas be ordered to undertake an accelerated main replacement program, that position is opposed by Peoples Gas, and even if the Commission ordered Peoples Gas to accelerate its main replacement, it is unclear to what degree the Commission would do so. In the absence of any such requirement, Peoples Gas' authorized return on equity should not be adjusted for Rider ICR, but if the Commission orders accelerated main replacement, then the adjustment should be proportional to any adjustment for Rider VBA in terms of the amount of distribution revenue covered by each rider.

### 10. Mr. Bodmer's Proposal

The Utilities trust that the Commission will see Mr. Bodmer's presentation in these cases for what it is. For all of his repeated use of the term "objective" to describe his proposed approach for setting utility authorized returns, it is precisely the opposite. He would have the Commission jettison, or at least discount substantially, the traditional cost of equity models in use throughout the country and strike out on an entirely new path. Instead of relying on models developed through decades of academic research and analysis designed to determine the investor required return using data readily available to and actually relied upon by investors, Mr. Bodmer would have the Commission replace the market expectations with its, or his, own judgment as to what returns investors should expect, or at least accept, for an investment in Illinois utilities. Moul Sur., NS-PGL Ex. PRM-3.0 Rev. at 13:280-283; Fetter Sur., NS-PGL Ex. 2.0 at 3:46-58.

As Mr. Fetter put it succinctly: "Any regulatory body that believes that its ROE determinations should be made in a vacuum, divorced from investor sentiment or consideration of alternative return levels offered in other jurisdictions, does so at its own peril." Fetter Sur., NS-PGL Ex. SMF-2.0 at 3:67 – 4:70. Reducing the returns of Illinois' public utilities in pursuit of a regulatory policy that caps utility market-to-book ratios at 1.0 would be extremely dangerous. Investors interested in the utility sector would take their dollars to other states with more supportive policies and the Illinois utilities would find it increasingly difficult and expensive to attract capital on reasonable terms and at reasonable cost. Moul, Tr. 468:8 – 469:14, 470:20 – 472:1. Utility stock prices – the very value of the utilities will fall – leaving them with less ability to raise the capital they require to provide service as required by law. Fetter Sur., NS-PGL Ex. SMF-2.0 at 5:113 – 6:137. As a former regulator, Mr. Fetter offers strong advice to the Commission. "It would be poor public policy, in my view, to depart from

accepted ratemaking approaches used throughout the nation at a time when markets are already unsettled and when the Utilities are sharing recessionary pressures with the entire global utility sector." Fetter Reb., NS-PGL Ex. SMF-1.0 at 9:170-174.

### 11. Cost of Equity Conclusion

"In this case, the Commission should authorize a cost of capital that will attract both debt and equity investors to continue to support the Utilities' financing needs." Fetter Reb., NS-PGL Ex. SMF-1.0 at 6:121-123. That has never been more true. The recent financial crisis and currently unsettled markets make it more important than ever for the Commission to support the Utilities' financial strength in order to ensure they maintain ready access to the capital at reasonable cost and on reasonable terms as the economy and markets rebound as we hope they do. With interest rate spreads between A-rated and BBB-rated utilities remaining very high, it is critical for the Utilities to maintain their current A/BBB split ratings. Any further downgrade can only increase the Utilities' capital costs, costs that will ultimately be borne by customers.

Consistent with the general trend in utility capital costs since the Utilities' last rate cases, the Commission should increase their cost of equity for 2010. The Utilities' proposed return of equity of 11.87% is the only proposal before the Commission that is consistent with the general trend in utility capital costs. By contrast, Staff and CUB-City propose that the Commission reduce the Utilities' returns, a result that is not credible under the circumstances and reflects undue bias from the Staff and CUB-City analysts' opinions about what investors should expect as opposed to what they actually expect and require.

### F. Weighted Average Cost of Capital

#### 1. Peoples Gas

For the reasons stated above and in the record, the Commission should approve an overall rate of return for Peoples Gas of 9.11%.

#### 2. North Shore

For the reasons stated above and in the record, the Commission should approve an overall rate of return for North Shore of 9.06%.

## VII. WEATHER NORMALIZATION – AVERAGING PERIOD (Uncontested)

The Utilities proposed using the average of the previous twelve years of weather data, ending in 2007, which results in 6,095 heating degree days. Marozas Dir., PGL Ex. BMM-1.0 at 8:133 – 9:151; Marozas Dir., NS Ex. BMM-1.0 at 8:135 – 9:153. No witness disagreed.

## VIII. PROPOSED RIDER ICR (PGL)

### A. Overview

Rider ICR proposed by Peoples Gas is a mechanism that will help enable Peoples Gas to accelerate the replacement of its aging cast iron and ductile iron ("CI/DI") mains and low-pressure distribution system. Rider ICR will do so by allowing Peoples Gas to recover a portion of its annual costs for this infrastructure program (capped at 5% of Peoples Gas' base rate revenues). Rider ICR also would flow back to customers the savings generated by the accelerated main replacement program. By allowing recovery of a portion of its construction costs for this program as they are incurred between rate cases, Rider ICR will enhance Peoples Gas' ability to incur the costs required to accelerate its ongoing replacement of CI/DI mains. This acceleration would bring numerous benefits to customers and the City including, but not

limited to, enhanced system safety, reduced system costs, potential new products, significant environmental benefits and the creation of jobs.

In its last rate case, the Commission rejected the Rider ICR proposal for three reasons:

> (i) Rider ICR as proposed in Peoples Gas' 2007 rate case did not account for savings generated by accelerated main replacement and thus, violated the single-issue ratemaking rule (*Peoples 2007* at 159-160);
>
> (ii) Rider ICR as proposed in Peoples Gas' 2007 rate case would have circumscribed the Commission's statutory power to initiate a proceeding in which Peoples Gas would carry the burden of proving the reasonableness of Rider ICR (*id*. at 157-158); and
>
> (iii) Peoples Gas failed to provide sufficient evidence and information concerning the proposed system modernization and identifying and quantifying reduced system costs and increased customer benefits to justify the Commission's approval of a system modernization proposal such as Rider ICR (*id*. at 162).

As explained below, Peoples Gas has addressed each of the Commission's previously expressed concerns. Rider ICR as proposed here eliminates the first two concerns by including a factor to flow savings generated back to customers and omitting any language that would circumscribe the Commission's statutory powers, as discussed *infra* in subsections B and D. With respect to the third concern, Peoples Gas has submitted comprehensive and detailed evidence concerning the proposed system modernization, its costs, and the numerous benefits it would provide to customers, discussed *infra* in subsection C. Peoples Gas also has adopted virtually all of the recommendations for modifications to Rider ICR made by Staff, which will provide for increased transparency and more thorough review of Rider ICR by the Commission.

### B. <u>Legal and Regulatory Issues</u>

The Commission has had an opportunity in recent rate case orders to review its legal authority to authorize riders, and has concluded that it has the authority to adopt a rider mechanism in proper situations and under circumstances that are lawful and reasonable. *See,*

*e.g.*, *Peoples 2007* at 139-140. The Illinois Supreme Court has affirmed that the Commission has the discretion to select the means by which rates are set and costs recovered, and the appropriateness of a rider mechanism in certain instances. *CUB*, 166 Ill. 2d at 137-139. Furthermore, the Commission has concluded that Illinois law prohibits single issue ratemaking only in the context of a rate case during the phase that balances the utility's cost and allowed revenues, and is not applicable to a proposed rider that merely facilitates direct recovery of a particular cost without upsetting the utility's revenue requirement. *Peoples 2007* at 142.

Rider ICR as proposed in this proceeding presents an appropriate situation for the Commission to use its discretion to authorize the use of a rider to facilitate the direct recovery of particular costs -- a portion of the costs of the main replacement program -- that will not upset Peoples Gas' revenue requirement because the proposed mechanism provides for the flow back of savings generated to customers. For the same policy reasons why the Commission authorized ComEd's Rider SMP and its Advanced Metering Infrastructure pilot (also known as "Smart Grid")[81] to encourage investment in the modernization of Illinois' utility infrastructure, the Commission should authorize Peoples Gas' proposed Rider ICR. Indeed, the evidence presented in this case of the measurable concrete and tangible benefits to customers that Rider ICR will help bring provides an even stronger basis for the Commission to authorize Rider ICR than the less clearly defined potential benefits that supported the Commission's authorization of ComEd's Smart Grid rider.

The following sections will review the legal authority of the Commission to authorize riders and the law regarding single issue ratemaking, and explain why Peoples Gas' proposed Rider ICR is proper and legal.

[81] *In re Commonwealth Edison Co.*, ICC Docket No. 07-0566, at 137-143 (Order Sept. 10, 2008).

### 1. **The Commission's Legal Authority to Authorize Riders**

In *City of Chicago v. Illinois Commerce Commission*, 13 Ill. 2d 607, 611 (1958) ("*City I*"), the Illinois Supreme Court established that the Commission has the authority to approve rate schedules that includes the power to adopt a set formula to recover costs in appropriate circumstances. The Court declared that the Commission is vested with the authority to make "pragmatic adjustments" as part of its ratemaking function. *Id*. at 618.

In reliance on *City I*, Illinois courts have reviewed and affirmed rider mechanisms in a number of different circumstances. *See City of Chicago v. Illinois Commerce Commission*, 246 Ill. App. 3d 403, 410-412 (1st Dist. 1993) ("*City II*") (affirming Commission's approval of a rider for the recovery of the marginal cost of providing non-standard service); *Central Illinois Light Co. v. Illinois Commerce Commission*, 255 Ill. App. 3d 876, 885-886 (3d Dist. 1993) ("*CILCO*"), *affirmed, CUB,* 166 Ill. 2d 1111 (affirming Commission's approval of rider mechanism for the recovery of coal tar remediation costs); *City of Chicago v. Illinois Commerce Commission*, 281 Ill. App. 3d 617, 627-629 (1st Dist. 1996) ("*City III*") (affirming Commission's approval of rider recovery of the utility's franchise costs); *see also Illinois Power Co. v. Illinois Commerce Commission*, 339 Ill. App. 3d 425, 434 (5th Dist. 2003) (recognizing that the Commission is authorized to set rates two ways: by base rates and by automatic cost recovery mechanisms such as riders). In *CUB*, the Illinois Supreme Court re-confirmed its decision in *City I* and established that the Commission has the authority to approve the direct recovery of particular costs through a rider. *CUB*, 166 Ill. 2d at 138.

### 2. **Single Issue Ratemaking**

The rule against single issue ratemaking applies only in the context of a general rate case, such as the present proceeding. *See Archer-Daniels-Midland Co. v. Illinois Commerce*

*Commission*, 184 Ill. 2d 391, 401-402 (1998); *CUB*, 166 Ill. 2d at 138. The rule is based on the principle that it would be improper to consider changes to one component of a utility's revenue requirement (operating costs plus rate base times rate of return on capital) in isolation because a change to one item of the revenue formula could be offset by a corresponding change in a different component of the formula. *See BPI II*, 146 Ill. 2d at 244-245.

Accordingly, the rule against single issue ratemaking is not violated where a rider merely facilitates the direct recovery of particular costs in a manner that either has no direct impact on or accounts for any corresponding changes to the components underlying the utility's rate of return so that there is no under- or over-recovery. *BPI II*, 146 Ill. 2d at 244-245; *CUB*, 166 Ill. 2d at 138; *City III*, 281 Ill. App. 3d at 627-629; *Peoples 2007* at 159-160.

### 3. Peoples Gas' Proposed Rider ICR is Proper and Legal

As demonstrated in subsection C, *infra*, proposed Rider ICR will help enable Peoples Gas to bring numerous substantial quantitative and qualitative benefits to customers through an accelerated main replacement program that greatly outweigh its costs. Accordingly, it would be appropriate for the Commission to authorize Rider ICR under the circumstances, so long as it would be legal to do so. The only legal challenge to Rider ICR suggested by certain parties in their testimony is that it would be a violation of the single issue ratemaking rule. As proposed, however, Rider ICR would not violate the single issue ratemaking rule.

In Peoples Gas' previous rate case, the Commission found that the version of Rider ICR proposed there violated the single issue ratemaking rule because it failed to account for savings generated by the accelerated main replacement program. *Peoples 2007* at 159-160. The Commission concluded that this would be a problem because, as explained in *BPI II*, this change in costs could offset the construction costs being recovered through Rider ICR, and would thus

risk an overstatement of the utility's overall revenue requirement. *BPI II*, 146 Ill. 2d at 244-245; *City III*, 281 Ill. App. 3d at 627-629.

Rider ICR proposed in the present case, however, corrects this problem by including a factor for offsetting savings generated by the accelerated program to customers, thus preventing any over or understatement of Peoples Gas' overall revenue requirements by Rider ICR. *See* PGL Ex. VG-1.1 at 90-91. Moreover, at the suggestion of Staff, this provision of Rider ICR has been further modified to require the re-calculation of this savings factor no less than every three years, with the Commission and other parties free to initiate proceedings to do so more frequently if necessary. Hathhorn Dir., Staff Ex. 1.0 at 43:1019 - 44:1037; Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 53:1173-1180; Hathhorn Dir., Staff Ex. 15.0 Att. G at 6. Accordingly, Rider ICR would not have a direct impact on Peoples Gas' rate of return, and thus, Rider ICR does not violate the rule against single issue ratemaking under *BPI II*, *CUB*, and *City III*.

It also should be noted that another legal concern raised by the Commission to the version of Rider ICR proposed in Peoples Gas' 2007 rate case was that it contained a provision that would prohibit the Commission from exercising its statutory power to initiate a proceeding under the Public Utilities Act requiring Peoples Gas to carry the burden of proving the reasonableness of Rider ICR. *Peoples 2007* at 157-158. The specific rider proposed in the present case does <u>not</u> contain any provisions of this nature. Indeed, Peoples Gas has submitted testimony that it believes the Commission (as well as other parties) would remain free to initiate whatever procedures are authorized under the Public Utilities Act in the future with respect to Rider ICR if it is approved. *See* Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 53:1173-1180.

Peoples Gas has submitted un-rebutted and unchallenged evidence of significant benefits that Rider ICR would help enable the company to bring to customers and the City. No legal

barrier exists to the adoption of Rider ICR as proposed by Peoples Gas. Consequently, the Commission should approve Rider ICR as proposed by Peoples Gas (with the recommended revisions of Staff accepted by Peoples Gas as described in subsection D(1), *infra*).

### C. The Costs and Benefits of Accelerated System Modernization

In its Order in Peoples Gas' 2007 rate case, the Commission provided specific guidance and direction pertaining to the evidence it needed to evaluate and approve Rider ICR. *Peoples 2007* at 162. In the present case, through the testimony of its expert witness, Salvatore Marano of Jacobs Consultancy, Peoples Gas has provided the in-depth, detailed information and analysis regarding the proposed system modernization and its costs and benefits that were requested by the Commission. Mr. Marano is eminently qualified to provide this information to the Commission, being a licensed professional engineer having 18 years of experience in the operation of gas utilities and 12 years of experience as an expert for both utilities and public utility commissions on numerous matters, including CI/DI main replacement projects. Marano Dir., PGL Ex. SDM-1.0 Rev. at 12:211 – 13:248. The following sections summarize the evidence in the categories outlined by the Commission in its previous Order.

#### 1. A Detailed Description and Cost Analysis of the Proposed System Modernization

Mr. Marano provides detailed testimony describing the physical nature of the modernized system as well as the expected approaches by Peoples Gas to implement the modernization. He first describes Peoples Gas' existing system and explains how the aging CI/DI mains require a higher level of risk management and generate a larger number of main leaks requiring repair. *Id*. at 15:284 - 17:316, 21:358 - 22:391, 26:462 - 27:480. Mr. Marano explains that these materials will be replaced by polyethylene ("PE") pipe materials and, when necessary, coated cathodically

protected steel, which are the state-of-the art in gas main and service materials. *Id*. at 23:397-401. The PE pipe being installed has a life expectancy of 80 plus years and is not subject to corrosion or stress-related cracking. *Id*. at 34:626-630.

Mr. Marano's testimony also explains in detail how Peoples Gas' system modernization will upgrade its distribution network from a low-pressure system to a medium-pressure system. The low-pressure system is a legacy from when customers received gas manufactured from coal and is prone to outages caused by water infiltration. *Id*. 7:130-138, 34:636-641. No low-pressure systems are installed today. *Id*. at 7:132-133, 34:641 - 35:643. Indeed, in the future, standard residential appliances may not be compatible with a low-pressure system. *Id*. at 38:703-708. Peoples Gas' upgraded system will provide customers with a modern medium-pressure distribution system that will provide many new functionalities and benefits. *Id*. at 7:133 - 8:155.

Mr. Marano's testimony also provides a detailed explanation as to the expected and recommended approaches to the accelerated main replacement program. *Id*. at 59:1075 - 63:1162. As the testimony illustrates, by accelerating and thus replacing larger amounts of main each year, Peoples Gas could add a zonal approach to the program to allow for greater economies of scale and coordination with the City and other utilities with respect to their infrastructure projects. *Id*. at 61:1119-1130. Furthermore, in response to testimony by Staff witness Harold Stoller, Peoples Gas worked with Mr. Marano and Jacobs Consultancy to prepare a preliminary plan of action demonstrating the company's diligence in preparing for and managing this anticipated project. *See* Marano Sur., NS-PGL Ex. SDM-3.0 at 2:35 - 6:135; NS-PGL Ex. SDM-3.1.

Mr. Marano also prepared and submitted a detailed cost analysis on behalf of Peoples Gas to show, as best as could be projected, what the construction costs would be for replacing its CI/DI mains at the current rate, which would have the replacement completed in the year 2059, and under a nineteen-year accelerated replacement scenario which would have Peoples Gas complete its replacement program by the year 2029. Marano Dir., PGL Ex. SDM-1.0 Rev. at 50:950 - 57:1023, 63:1164 - 65:1218; PGL Exs. SDM-1.13 Rev. - 1.19. No party submitted evidence or testimony rebutting or challenging the assumptions underlying Mr. Marano's cost model or analysis.[82] What this analysis concluded is that the accelerated main replacement program would cost $432 million (2010 dollars) less in construction costs than Peoples Gas' current main replacement program over what would be its 49-year life-span. Marano Dir., PGL Ex. SDM-1.0 Rev. at 54:997-1000; PGL Exs. SDM-1.16 Rev. and SDM-1.18 Rev. After subtracting the incremental costs (termed "Incremental O&M" in the analysis) of program management and labor (such as meter installation work) associated with the accelerated program that are projected to be $159.7 million, the net construction cost savings from accelerating the main replacement program construction are projected to be $272.3 million. Marano Dir., PGL Ex. SDM-1.0 Rev. at 54:1006-1010; PGL Ex. SDM-1.19; Marano Reb., NS-PGL Ex. SDM-2.0 at 12:254-260.

Furthermore, the evidence shows that the new distribution system would provide savings in Peoples Gas' ongoing operations and maintenance ("O&M") costs by substantially reducing the amount of leak repairs, leak surveys, leak rechecks, emergency responses, regulator station

[82] While AG/CUB witness Scott Rubin addresses the fact that Mr. Marano's cost model is based on certain assumptions regarding material and labor cost escalation rates in his rebuttal testimony (Rubin Reb., AG/CUB Ex. 6.0 at 4:77 - 5:88), Mr. Rubin admitted on cross examination that he did not perform any analysis to determine the accuracy of Mr. Marano's assumptions or a specific analysis to develop his own estimates of material and cost escalation rates, although he had the ability to do so. Rubin Tr. at 988:7 - 989:12.

inspection and maintenance, vault survey and maintenance, lost gas and inside safety inspections. Marano Dir., PGL Ex. SDM-1.0 Rev. at 55:1016-1017, 65:1220 - 1224; PGL Ex. SDM-1.17 Rev. Again, no party submitted evidence or testimony challenging the assumptions underlying this analysis or the fact that these savings would be generated. Accelerating the main replacement program would bring these costs savings to customers sooner. Mr. Marano's testimony and analysis demonstrates that compared to the scenario in which Peoples Gas continues its current main replacement plan, the accelerated scenario would generate a total of $244 million in O&M cost savings over that same time period. Marano Dir., PGL Ex. SDM-1.0 Rev. at 54:1000-1001, 55:1016-1017; PGL Ex. SDM-1.17 Rev.

In an attempt to support their opposition to the method of cost recovery, but not as to whether the main replacement program should be accelerated[83], AG/CUB witness Scott Rubin prepared a revenue requirement analysis and argued that "the costs customers actually would pay" if Rider ICR is authorized would be greater than Peoples Gas' current main replacement program. Rubin Reb., AG/CUB Ex. 6.0 at 6:104-113. Despite this statement in his testimony, Mr. Rubin's analysis does not accurately show what customers would pay under Rider ICR. Indeed, Mr. Rubin admits as much in his cross examination, stating:

> My analysis is not limited to Rider ICR. My analysis is a revenue requirements analysis. The Company's proposal for Rider ICR would recover a portion of those costs through the rider and a portion of those costs through base rates.

Rubin Tr. at 992:6-10.

Mr. Rubin's analysis assumes customers will begin paying revenue requirements for the entire amount of capital investment made each year under the accelerated program and ignores the fact that Rider ICR contains a cap equal to 5% of base rate revenues. Grace Sur., NS-PGL

[83] On cross examination, Mr. Rubin confirmed that he has no opinion on whether the main replacement program should be accelerated. Rubin Tr. at 984:9-14.

Ex. VG-3.0 at 37:819-826; Grace Tr. at 166:13 - 171:10. Thus, while Mr. Rubin's revenue requirement analysis shows customers paying revenue requirements of $28.1 million, $43.6 million and $60.0 million in years 2011 through 2013, respectively (*see* AG/CUB Ex. 6.06), in reality, the revenue requirement under Rider ICR for those years would be $9.6 million, $29.8 million and $29.8 million. Grace Sur., NS-PGL Ex. VG-3.0 at 38:827-829. On cross examination, Mr. Rubin admitted that this is how Rider ICR actually would work and that he did not perform the "interesting mathematical exercise" to determine how revenue requirements really would be determined, but rather merely assumed it would not make a difference. *See* Rubin Tr. at 993:6 - 994:5. Consequently, although AG/CUB purports to offer this analysis to argue about the impact of Rider ICR on customers (*see* Rubin Reb., AG/CUB Ex. 6.0 at 6:111-113), it is completely divorced from the reality of how Rider ICR would work and thus, should be given little or no weight.

Moreover, Mr. Rubin's analysis only is able to generate larger revenue requirement numbers for the accelerated program than the current replacement program by inappropriately limiting his calculations to the 49-year period when construction would take place. Rubin Tr. at 994:6-12. Mr. Rubin claims he used this 49-year period because that is the timeframe that Mr. Marano used for his cost-benefit analysis, but doing so was improper and is the source for Mr. Rubin's artificially inflated results. Mr. Marano's analysis was looking solely to compare the costs of construction and O&M costs that would be incurred during the timeframe of the current replacement program versus what they would be if the program was accelerated. Revenue requirements on those amounts, however, as Mr. Rubin himself testifies, continue "for many years into the future" after those costs are incurred and added to the rate base. Rubin Reb., AG/CUB Ex. 6.0 at 2:31-32; Rubin Tr. at 995:4-9, 1008:20 - 1009:5.

Thus, to fairly compare the revenue requirements associated with the accelerated main replacement program to the revenue requirements that would be generated by the current program, the overall revenue requirements generated under each scenario should be compared, not just a snapshot of time that provides an outcome that AG/CUB desire. Mr. Rubin, however, failed to carry his analysis past the end of the 49-year construction period even though the revenue requirements for both programs continued past that time. Rubin Tr. at 1008:20 - 1009:5. Mr. Rubin performed no analysis and made no assumptions as to what would occur past that 49-year period, despite the continuation of revenue requirements past that time. *See* Rubin Tr. at 1000:9-19. Indeed, Mr. Rubin was forced to admit on cross examination that if his analysis was carried out until the capital investments were completely depreciated, the current main replacement program would generate an overall larger revenue requirement than the accelerated main replacement program. Rubin Tr. at 1010:17 - 1011:10. Thus, assuming *arguendo* that it accurately reflected the impact of Rider ICR (which it does not), the AG/CUB analysis would actually support the adoption of Rider ICR if performed over the proper timeframe.[84]

In any event, however, the AG/CUB analysis of revenue requirements lacks sufficient foundation as a model of how Rider ICR would work and impact customers, and thus, should be given no weight.

### 2. An Identification and Evaluation of the Range of Technology Options Considered and Analysis and Justification of the Proposed Technology Approach

Peoples Gas provided evidence that the materials to be used in replacing its aging CI/DI mains -- PE and coated cathodically protected steel -- are the state-of-the art in gas main and

[84] Moreover, to the extent the Commission believes that revenue impacts should be considered, it also should consider the evidence presented by Mr. Marano that utility revenues have a positive impact on local economies of 1.2 to 2.4 times the revenue amounts. Marano Sur., NS-PGL Ex. SDM-3.0 at 11:232-241.

service materials. Marano Dir., PGL Ex. SDM-1.0 Rev. at 23:397-401. Likewise, the upgrade to a medium-pressure from a low-pressure distribution system will bring Peoples Gas current with the standard for natural gas distribution systems, as low-pressure systems are a legacy of a bygone era, as low-pressure systems are no longer being installed and appliances for such systems being discontinued. *Id*. 7:130-138, 34:636-643, 38:703-708. A medium-pressure system also is less costly to construct because it allows for smaller diameter pipe to be used, and can take advantage of PE pipe, which is less expensive than coated steel pipe. *Id*. at 35:651-654.

Mr. Marano's testimony discusses the technology options used and alternatives considered by Peoples Gas, explaining that its use of directional drilling technology reduces construction restoration costs and eliminates the need to dispose of spoil caused by open trenching. *Id*. at 58:1053 - 59:1065. Mr. Marano also describes the options available for approaches to pipe replacement and explains why he recommends the use of a zonal approach to create economies of scale that may create further cost savings as well as provide benefits to the City and other utilities via the coordination of their respective infrastructure projects. *Id*. at 59:1075 - 62:1135.

Peoples Gas also provided testimony explaining how its "double decking" of mains -- that is, placing main in the parkways on each side of a street rather than a single main in the middle of the street -- would create several benefits:

- remove gas main from the congestion of utilities in the street;
- reduce future maintenance costs;
- reduce the potential for excavation damage to gas facilities from third parties;
- reduce the average length of service lines and number of long side services; and
- reduce program installation costs.

*Id*. at 45:835-841, 67:1252-1263.

### 3. A Detailed Identification and Description of the Functionalities of the New System, Related Both to System Operation as well as on the Customer Side of the Meter, and an Identification and Justification of Functionalities Foregone

Peoples Gas has introduced a considerable amount of evidence as to the functionalities of the new system as to its operation and to customers and other interested parties, and the benefits provided by those functionalities. With respect to the old low-pressure system, Peoples Gas' expert Mr. Marano testified that there will not by any functionalities foregone when that system is replaced. Marano Dir., PGL Ex. SDM-1.0 at 7:130-138, 47:880-882. No party has challenged this testimony or submitted any evidence to the contrary.

As for the new system, Mr. Marano testified that it will be simpler, more reliable and be more optimal in design. *Id*. at 44:826 - 828. Over 300 medium to low pressure regulator stations, along with their maintenance costs, can be eliminated and replaced with 54 new high to medium pressure regulator stations with a common design that will reduce construction costs and future maintenance costs. *Id*. at 44:828-831. Water infiltration common with low-pressure systems, which can cause outages, will be eliminated. *Id*. at 44:831. The moving of meter sets to outside the house will provide greater access and improved safety, and the new meters combined with the constant pressure provided by the modernized system will measure gas usage more accurately. *Id*. at 45:843-848.

From a system operation and maintenance perspective, the new regulator stations will be in the parkway, providing safe access and reduced impact on traffic. *Id*. at 45:852-853. This will also benefit the City, which will encounter fewer regulator vaults that could impede street construction. *Id*. at 46:856-857. Eliminating the medium to low pressure regulator stations will

reduce the amount of training, inspection and maintenance necessary, thus also reducing the potential for human error. *Id*. at 32:574-577, 45:853 - 46:856. The increased use of PE pipe will reduce the risk of leaks caused by corrosion and reduce the amount of pipe required to be leak surveyed annually. *Id*. at 46:859-861.

Customers also will benefit from a modernized system. Customers will no longer need to install costly gas boosters and safety back-check valves to provide elevated pressures for modern energy efficient appliances and back-up generators. *Id*. at 33:598-604, 46:868-871. Service lines will have excess flow valves -- unavailable with a low-pressure system -- which will reduce the potential property damage caused by a damaged service line. *Id*. at 31:565-572, 46:871-873. Furthermore, emergency response personnel, such as the Fire Department, will be able to shut off gas to a building from the outside meter sets, which potentially could reduce property damage in fire and other emergency situations. *Id*. at 46:876-878.

The following is a list of additional beneficial functionalities that the modernized system will provide:

- fewer joint leaks because PE pipe is fused and steel pipe welded (*id*. at 35:656-657);
- medium-pressure meter sets will have a pressure regulator with overpressure relief and meter shutoff valve before the meter (*id*. at 32:579-581);
- meters relocated outside will eliminate the need for inside safety inspections (*id*. at 32:581-582);
- the use of PE pipes will enable crews to isolate gas leaks quickly by closing an existing valve or squeezing off the pipe upstream and downstream from the leak (*id*. at 32:589-591); and

- moving gas mains out of the streets and into parkways will result in a reduction of third-party excavation damage and accidental gas line cuts and an increase in worker safety (*id*. at 8:146-147, 32:592-596).

#### 4. Analysis of the Benefits of the System Modernization, Both to System Operation as well as to Customers, Including Reductions in System Costs, and an Analysis of the Range and Benefits of Potential New Products and Services for Customers Made Possible by the System Modernization

In addition to the beneficial functionalities described in subsection 3, *supra*, Peoples Gas' proposed system modernization will provide additional benefits to customers, including enhanced system safety, reduced system costs, potential new products and significant environmental benefits. Furthermore, acceleration of Peoples Gas' main replacement program will create additional jobs.

As Mr. Marano describes in detail in his testimony, Peoples Gas' aging CI/DI mains are comprised of materials that pose a risk of catastrophic failures, which present risk to customers and Peoples Gas' personnel that the company must manage. *Id*. at 21:358 - 23:396. While Peoples Gas does a good job managing these risks, these materials ultimately will fail and must be replaced, with the costs of managing this system continuing to increase as it ages. *Id*. at 29:510-517. Peoples Gas' proposed system modernization will eliminate the risks, along with the risk management costs they require, posed by the existence of these higher-risk materials in the company's distribution system. *Id*. at 29:519 - 30:538.

As discussed earlier, modernizing Peoples Gas' distribution network will generate savings in Peoples Gas' O&M costs that will benefit customers. It is projected that if Peoples Gas accelerated its main replacement program, those O&M savings would amount to $244 million between the years 2011 and 2059 because of a substantial reduction in the amount

of leak repairs, leak surveys, leak rechecks, emergency responses, regulation station inspection and maintenance, vault surveys and maintenance, lost gas and inside safety inspections. *Id*. at 54:1000-1001, 55:1016-1017, 67:1265 - 68:1281. Customers would further benefit from the synergies and efficiencies in system maintenance by no longer being inconvenienced by the need to schedule inside safety inspections, suffer from water infiltration outages or the freeze-up of low-pressure risers. *Id*. at 38:683 - 39:696.

A medium-pressure system upgrade will enable customers to more easily use technologies and appliances, particularly high-efficiency appliances, not compatible with the low-pressure system now in place. *Id*. at 38:700-708. Currently, to operate these types of appliances and natural gas-fired back-up generators on the low-pressure system, customers are required to install and maintain electric-powered gas pressure booster systems which can cost between $20,000 and $50,000. *Id*. at 39:711-713, 40:729-735. This would be important for facilities such as schools, hospitals and emergency services providers, which are required by Chicago code to have back-up generators installed. *Id*. at 40:740-744. Those facilities now located on the low-pressure system would need a pressure booster system installed to use a natural gas-powered generator (*id*.), or else use gasoline or diesel powered versions which are less environmentally friendly and potentially dangerous. *Id*. at 40:746 - 41:754.

A medium-pressure system would allow all customers to install high-efficiency appliances such as tankless water heaters, fan-assisted heaters, home generators and commercial-grade cooking appliances. *Id*. at 39:711-717. Not only is the availability of such high-efficiency appliances important for the environment and energy-conservation (*see id*. at 43:800-808), but they will help customers save money as well. For example, a tankless water heater is estimated

to cost $265 to operate a year, as opposed to $326 for a 40-gallon gas heater and $453 for a 40-gallon electric tank. *Id*. at 39:719-724; PGL Ex. SDM-1.11.

Another financial benefit to customers of the new medium-pressure system will be that it will allow customers to use corrugated steel piping, which is more economical and will allow customers to reduce their building construction costs. *Id.* at 40:735-738.

Mr. Marano's testimony details other significant environmental benefits of system modernization, as well. The elimination of Peoples Gas' CI/DI mains and their replacement with PE and protected steel pipe will dramatically reduce the amount of greenhouse gas emissions from the company's mains. Based on a study by the U.S. Environmental Protection Agency, Mr. Marano estimates that by accelerating the main replacement program, Peoples Gas could further reduce the emission of greenhouse gases by approximately 10,500 Mcf per year. *Id*. at 41:769 - 42:781. Upgrading the system to medium-pressure also will eliminate the need for the collection, testing and disposal of water that enters the gas distribution system. *Id*. at 42:783 - 43:798.

Another important benefit of accelerating the main replacement program to the City would be the creation of a substantial number of jobs, as additional people will be needed to perform the construction work (both internal and external to the company), the meter installations and relights of service and the management of the work. *See Id*. at 72:1379 - 74:1413. When questioned at the hearing as to whether Peoples Gas could accelerate the main replacement program without hiring additional personnel, Mr. Marano testified: "Absolutely not." Marano Tr. at 887:22 - 888:3.

It is significant to note that even the AG/CUB witness who testified in opposition to Rider ICR agreed on cross examination that the decision on whether to implement an

infrastructure investment program such as Rider ICR should not be based solely on cost, but on factors such as safety and reliability, as well. Rubin Tr. at 984:15-18. Here, the evidence demonstrates that Rider ICR would generate not only financial benefits for customers in the form of construction and O&M cost savings, but additional benefits to customers such as enhanced safety, energy conservation, increased functionalities and appliance choices and reduced environmental impacts. The evidence in the record strongly weighs in favor of authorizing Rider ICR to help bring these benefits to customers sooner than otherwise possible.

### D. Rider ICR Tariff

Peoples Gas' Rider ICR is modeled after, but not identical to, the Commission's rules applicable to water and sewer utilities (83 Ill. Admin. Code Part 656). Grace Dir., PGL Ex. VG-1.0 Rev. at 35:783 - 36:784. In response to proposals from the Staff, Peoples Gas modified the rider. Staff included the revised rider with its rebuttal testimony. Hathhorn Reb., Staff Ex. 15.0, Att. G. There are only two contested issues related to the tariff language.

#### 1. Uncontested Tariff Issues

Rider ICR would apply to Service Classification Nos. 1, 2, 4, and 8. Each year Peoples Gas would file an information sheet stating the Rider ICR charge to be in effect for the nine-month period of April through December. The first charge would be effective April 1, 2011. Grace Dir., PGL Ex. VG-1.0 Rev. at 35:780 - 36:785; PGL Ex. VG-1.14 Rev. (form of report); Hathhorn Reb., Staff Ex. 15.0, Att. G at 1 and 5. After the first effective period, by March 31 each year, Peoples Gas would file to initiate an annual reconciliation proceeding. Also, each year beginning in 2012, it would submit to Staff an internal audit report. Grace Dir., PGL Ex. VG-1.0 Rev. at 36:798 - 37:823; Hathhorn Reb., Staff Ex. 15.0, Att. G at 5-7.

As stated, Staff proposed, and Peoples Gas agreed to, several modifications to Rider ICR. Those accepted modifications, shown in Hathhorn Dir., Staff Ex. 15.0, Att. G, are:

- clarify the wording of the cap that limits recoveries under Rider ICR (Hathhorn Dir., Staff Ex. 1.0, pp. 36:866 - 37:869; Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 51:1119-1122; Hathhorn Reb., Staff Ex. 15.0 Att. G at 2);
- add more specific language for the annual reconciliation proceeding, including a filing date and a statement that the reconciliation will include a determination that costs incurred were prudent, just and reasonable (Hathhorn Dir., Staff Ex. 1.0 at 37:872-875 and 38:895-900; Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 51:1119-1122, and 51:1139 - 52:1142; Hathhorn Reb., Staff Ex. 15.0 Att. G at 5);
- add four specific tests that the annual internal audit would include (Hathhorn Dir., Staff Ex. 1.0 at 38:903 - 39:916; Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 52:1143-1145; Hathhorn Reb., Staff Ex. 15.0 Att. G at 7);
- update the initial QIP Percentage in the formula that calculates the Rider ICR charge; specifically, the initial QIP Percent would be 90%, rather than 94%, of the Account 383 ("House Regulators") amount in the calculation (Hathhorn Dir., Staff Ex. 1.0 at 39:919-921; Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 52:1146-1148; Hathhorn Reb., Staff Ex. 15.0 Att. G at 2);
- remove Factor IOM (incremental operation and maintenance expenses) from the calculation because the costs are either recoverable in other factors in the calculation or minimal (Hathhorn Dir., Staff Ex. 1.0 at 39:926 - 41:967; Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 52:1149-1151; Hathhorn Reb., Staff Ex. 15.0 Att. G at 4);

- exclude incentive compensation costs from the calculation although Peoples Gas agreed only for the purpose of Rider ICR in this proceeding; it generally disagrees with Staff's position on recovery of such costs (*see* Section V(C)(1), *supra*) (Hathhorn Dir., Staff Ex. 1.0 at 41:970 - 42:996; Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 52:1152-1159; Hathhorn Reb., Staff Ex. 15.0 Att. G at 3);
- commit to update, no less than every three years, the "actual savings" factor, which would initially be $6,000 per mile of cast iron and ductile iron abandoned during the reconciliation year (Hathhorn Dir., Staff Ex. 1.0 at 43:1019 - 44:1037; Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 53:1171-1180; Hathhorn Reb., Staff Ex. 15.0 Att. G at 6).

The Staff withdrew two recommended tariff changes. First, it withdrew a proposal that Rider ICR be effective no sooner than sixty days after the final order date. Hathhorn Reb., Staff Ex. 15.0 at 33:723-730. Second, it withdrew a proposal to net cost savings resulting from moving meters outside against meter installation costs. Staff acknowledged that such savings were likely to be very small. Hathhorn Reb., Staff Ex. 15.0 at 33:731-742.

### 2. <u>Contested Tariff Issues</u>

First, Staff proposed requiring Commission approval of a plan for Peoples Gas' accelerated replacement program. Based on these proposals, Staff proposed that the tariff state that Peoples Gas could collect no charges until Commission approval of the plan. Hathhorn Dir., Staff Ex. 1.0, pp. 42:999 - 43:1004; Hathhorn Reb., Staff Ex. 15.0 at 34:748-755. For the reasons discussed in Section IX, *infra*, no review and pre-approval of an implementation plan is justified in light of the evidence demonstrating Peoples Gas' diligence in proceeding with the

necessary planning for an accelerated main replacement program, and thus, no tariff change is necessary on this ground.

Second, Staff, in conjunction with its proposal to update the "actual savings" factor at least every three years, proposed that Rider ICR include language to provide for a more frequent update if demonstrated to be needed by Peoples Gas or any other party. Hathhorn Dir., Staff Ex. 1.0 at 44:1034-1037; Hathhorn Reb., Staff Ex. 15.0 at 34:759 - 35:771. The requested language is unnecessary. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 53:1171-1180. The Public Utilities Act affords the Commission, Peoples Gas and others means to address concerns with any provision in Peoples Gas' Schedule of Rates for Gas Service. It is unnecessary for Rider ICR to specifically state this fact for a single element.

## IX. STAFF PROPOSALS REGARDING ACCELERATION OF CAST AND DUCTILE IRON MAIN REPLACEMENT PROGRAM FOR PEOPLES GAS

Staff, through its witness, Harold Stoller, has made three proposals regarding Peoples Gas' proposed acceleration of its main replacement program:

- The Commission should order Peoples Gas to conduct the accelerated main replacement program as outlined in Mr. Marano's testimony (Stoller Dir., Staff Ex. 14.0 at 6:161; Stoller Reb., Staff Ex. 28.0 at 6:155-160);
- The Commission should order Peoples Gas to present a fully-developed plan for carrying out the main replacement program and obtain Commission approval of that plan in a docketed proceeding, with the plan analyzed by an independent consultant to be retained by the Commission at Peoples Gas' expense (Stoller Dir., Staff Ex. 14.0 at 2:29-34); and

- The Commission should order Peoples Gas to return with an updated analysis every three years to be analyzed by an independent consultant to be retained by the Commission at Peoples Gas' expense (*Id*. at 2:35-40).

Staff has performed no independent analysis to support any of these recommendations and, more importantly, has failed to make any showing of their necessity. Consequently, the Commission should deny these three recommendations.

### A. Staff Has Failed to Make a Showing of Necessity for the Accelerated Plan to be Ordered Under Section 8-503 of the Public Utilities Act

Mr. Stoller's recommendation that Peoples Gas be ordered to expedite the replacement of its CI/DI mains from the perspective of "maintaining public safety" is solely based on Mr. Marano's testimony concerning Peoples Gas' distribution system. *Id*. at 5:135 - 6:140. The Commission's authority to issue such an order would come from Section 8-503 of the Public Utilities Act, which provides:

> Whenever the Commission, after hearing, shall find that … repairs or improvements to, or changes in, the existing plant, equipment, apparatus, facilities or other physical property of any public utility … are necessary and ought reasonably to be made … the Commission shall make and serve an order authorizing or directing that such … repairs, improvements or changes be made … in the manner and within the time specified in said order ….

220 ILCS 5/8-503. Thus, before the Commission may enter such an order under Section 8-503, it must find that the changes to be made -- here, the acceleration of the main replacement program -- "are <u>necessary</u>." *Id*. (emphasis added).

The only "need" testified to by Mr. Stoller to justify his recommendation is "public safety." While there is voluminous evidence that accelerating Peoples Gas' main replacement program would provide many benefits for customers, there is not one iota of evidence in the record that the program's immediate acceleration is necessary to prevent or eliminate a public

safety concern. In fact, Mr. Marano testified that there is no immediate danger posed by Peoples Gas' current system and that Peoples Gas does a good job managing the risks posed by the current system. Marano Dir., PGL Ex. SDM-1.0 Rev. at 29:510-512. Indeed, Staff witness Mr. Stoller agrees that there is no evidence in the record that Peoples Gas' system is not safe or not being operated safely at the present time. Stoller, Tr. at 899:6-13.

While Mr. Stoller testifies as to his "belief" that Peoples Gas cannot be relied upon to conduct its main replacement program appropriately without a Commission ordered timeline (Stoller Dir., Staff Ex. 14.0 at 6:154-159), Staff provides no evidence to support this belief. Staff's attempt to rely on Peoples Gas' progress in replacing its CI/DI mains in light of previous consulting reports regarding the main replacement program is of no avail. Although Mr. Stoller relies upon the recommendations of an original study conducted by Zinder Engineering, Inc. ("Zinder"), in 1981 to argue that Peoples Gas had not diligently pursued the recommended pace of main replacement (Stoller Reb., Staff Ex. 28.0 at 4:106 - 5:123), he fails to acknowledge two facts that completely undermine his conclusion. First, Mr. Stoller fails to point out that the 2030 completion date in the 1981 Zinder report was only for specific CI/DI mains buried in clay soil, not Peoples Gas' entire CI/DI main system. Doerk Sur., NS-PGL Ex. ED-3.0 at 4:73-77. Second, Mr. Stoller fails to acknowledge that a subsequent, more in-depth study by ZEI, Inc. (a successor to Zinder) concluded that the target date for replacing the CI/DI mains should be pushed back from 2030 to 2050 based on an economic (not safety) analysis. *Id*. at 4:80 - 5:90. When the recommendations from all of the studies performed on Peoples Gas' main replacement program prior to this proceeding are compared against the company's actual performance, the evidence proves that Peoples Gas achieved a replacement rate greater than recommended by those consultants. *Id*. at 5:107 - 6:120.

Accordingly, there is no evidence that acceleration of the main replacement program is necessary for public safety or that Peoples Gas cannot be relied upon to conduct its main replacement program reasonably without an order by the Commission. Staff's recommendation, therefore, should be denied.

### B. Staff Has Failed to Demonstrate a Need for Pre-Approval of Peoples Gas' Plan for Implementing an Accelerated Main Replacement Program or Justification for the Costs of Additional Consultants

Staff also has failed to demonstrate the need to initiate a separate docketed proceeding to analyze and approve Peoples Gas' plan for implementing its accelerated main replacement program. Such micro-management of Peoples Gas' operations is not the proper role for the Commission or Staff, especially in light of the fact that Staff has submitted no evidence demonstrating that Peoples Gas is incapable or unwilling to take the actions necessary to implement and execute an accelerated main replacement program on its own.

Indeed, Peoples Gas submitted evidence that it engaged Mr. Marano and Jacobs Consultancy and already has prepared an initial plan of action and begun working on the type of detailed implementation plan outlined by Mr. Marano in his testimony. *See* Marano Dir., PGL Ex. SDM-1.0 Rev. at 69:1313 - 74:1413; Marano Reb., NS-PGL Ex. SDM-2.0 at 4:89 - 8:167; Marano Sur., NS-PGL Ex. SDM-3.0 at 2:35 - 6:135; NS-PGL Ex. SDM-3.1. This evidence contradicts Mr. Stoller's "beliefs" and demonstrates that Peoples Gas is capable of managing, implementing and executing an accelerated main replacement program in a reasonable and prudent manner without prior approval by Commission.

Similarly, Staff has made no showing that the retention of independent consultants by the Commission at Peoples Gas' expense is necessary to ensure Peoples Gas is conducting an

accelerated main replacement program properly.[85] The Commission's authority to order such a management audit or investigation is provided by Section 8-102 of the Public Utility Act. 220 ILCS 5/8-102. Section 8-102 requires that the Commission have reasonable grounds to believe that the investigation or audit "is necessary to assure that the utility is providing adequate, efficient, reliable, safe, and least-cost service" or that it is "likely to be cost-beneficial in enhancing the quality of service or the reasonableness of rates therefor." *Id*. Staff has made neither a showing of necessity nor a showing that the benefits such consultants might provide would justify their cost. Indeed, Staff has not even investigated what the costs of such consultants might be. Stoller Tr. at 900:2-6. Thus, at this time, in light of the evidence of Peoples Gas' diligence and proactive efforts, and lack of evidence demonstrating their need or benefits, no justification exists at this time for imposing the cost of additional consultants on Peoples Gas.

Staff's recommendations further ignore the fact that if, at anytime in the future, there is evidence that Peoples Gas is mismanaging the accelerated main replacement program, moving too slowly or imprudently incurring costs, Staff or other parties have the ability to initiate proceedings to correct any such problems <u>if and when such need arises</u>. Rider ICR would require annual reporting and audits, and the costs recovered via the rider will be subject to annual reconciliation review. Cost savings will be required to be updated no less than every three years. The reporting procedures required by Rider ICR would provide adequate opportunities for monitoring of program milestones and efficiency. *See* Marano Sur., NS-PGL Ex. SDM-3.0 at 6:117-130. Moreover, Peoples Gas maintains the position that it has consistently represented throughout this proceeding that it is willing to provide additional reporting or updating on the

[85] By use of the term "Peoples Gas' expense," Mr. Stoller is not recommending or opining on the recoverability of such costs by Peoples Gas in subsequent rate cases. Stoller, Tr. at 899:17 - 900:12.

program if the Commission requests or requires it. As conceded by Mr. Stoller during cross examination, nothing would prevent the Commission from taking action to initiate an investigation of the accelerated main replacement program or order the retention of consultants at some future time if it becomes necessary to do so. Stoller, Tr. at 901:13 - 902:17.

In short, Staff's recommendations as to the retention of independent consultants to review a plan and subsequent updates, as well as for Commission pre-approval of the company's implementation plan, also should be denied. Should the Commission decide to accept Staff's recommendations as to ordering the retention of consultants, such order should be made pursuant to its authority under Section 8-102 of the Public Utilities Act, with the costs of the consultants borne initially by Peoples Gas to "be recovered as an expense through normal ratemaking procedures" in the company's next rate case.

## X. OTHER NEW RIDERS

### A. Rider UEA (Withdrawn)

The Utilities each proposed a Rider UEA, Uncollectible Expense Adjustment to recover gas cost-related Account 904 Uncollectible Accounts expenses through a factor that the Utilities would apply to customers' bills, rather than through base rates. Grace Dir., NS Ex. VG-1.0 Rev. at 30:661 - 31:672; Grace Dir., PGL Ex. VG-1.0 Rev. at 34:748-759. Subsequent to the filing, legislation (Public Act 96-0033) went into effect that allows gas utilities to file to recover certain incremental Uncollectible Accounts expenses through an automatic adjustment mechanism. Bridal Reb., Staff Ex. 19.0 at 5:94-98; 220 ILCS 5/19-145. The Utilities withdrew their proposed Rider UEA. Grace Sur., NS-PGL Ex. VG-3.0 at 38:832-833.

### B. Rider FCA (NS) (Uncontested)

North Shore proposed Rider FCA, Franchise Cost Adjustment. North Shore has franchise agreements with local governmental units so that it may use public rights of way to deliver gas to customers in those areas. Under these agreements, North Shore compensates the governmental unit. Under Rider FCA, beginning May 1, 2010, North Shore would annually calculate a per customer charge based on the costs imposed by each governmental unit and applicable to customers within the boundaries of the governmental unit. The Commission has approved similar mechanisms for other utilities (Commonwealth Edison Company; Northern Illinois Gas Company ("Nicor")).[86] Grace Dir., NS Ex. VG-1.0 Rev. at 31:683 - 33:718.

Only Staff addressed proposed Rider FCA, and it recommended that the Commission approve the rider. Boggs Dir., Staff Ex. 11.0 at 22:434-440.

### C. Rider GCA (NS) (Uncontested)

North Shore proposed Rider GCA, Governmental Agency Cost Adjustment. Local governmental units may impose costs on North Shore that are incremental to those included in base rates. North Shore would annually calculate a per customer charge based on the costs imposed by each governmental unit and applicable to the customers within the boundaries of the governmental unit. The Commission has approved similar mechanisms for Commonwealth Edison Company and Nicor.[87] Grace Dir., NS Ex. VG-1.0 Rev. at 33:720 - 34:750.

Only Staff addressed proposed Rider GCA, and it recommended that the Commission approve the rider. Boggs Dir., Staff Ex. 11.0 at 22:442 - 24:488.

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[86] *ComEd 2005* at 7; *In re Northern Illinois Gas Company d/b/a Nicor Gas Company*, ICC Docket No. 04-0779, at 188 (Order Sept. 20, 2005) ("*Nicor 2004*"); *Nicor 2008* at 128 (approving modified version of existing rider).

[87] *ComEd 2005* at 267-269; *Nicor 2004* at 188.

## XI. COST OF SERVICE

### A. Overview

Only the Utilities prepared and submitted embedded cost of service studies ("ECOSSs"). Each of the Utilities used its ECOSS to develop its rate design proposals. Hoffman Malueg Dir., NS Ex. JCHM-1.0 at 1:15-16 and Exs. JCHM-1.1 - 1.9; Hoffman Malueg Dir., PGL Ex. JCHM-1.0 Rev. at 1:15-16 and Exs. JCHM 1.1 - 1.9. Neither Staff nor any party contested the adequacy and sufficiency of the ECOSSs. Of the many assumptions, calculations and decisions involving functionalization, classification and allocation that make up the studies, there is only one contested issue. That issue is the narrow, but important, question of how properly to classify Account 904 ("Uncollectible Accounts"). This classification decision has significant rate design ramifications. The Utilities' approaches are consistent with cost causation principles and lead to a simplified rate design. Additionally, there is a recommendation concerning the sales forecast that, due to its incompleteness, could substantially impair the Utilities' ability to prepare the ECOSSs to support final rates.

### B. Embedded Cost of Service Study

The ECOSS preparation involves three fundamental steps: (1) cost functionalization, which identifies and separates plant and expenses into categories such as production, storage, transmission, distribution and customer; (2) cost classification, which separates the functionalized plant and expenses into commodity, demand and customer; and (3) cost allocation, which allocates the functionalized and classified costs to the customer classes. The most important theoretical principle underlying a cost of service study is that cost incurrence should follow historical embedded cost causation. Hoffman Malueg Dir., NS Ex. JCHM-1.0 at 7:150 - 9:200; Hoffman Malueg Dir., PGL Ex. JCHM-1.0 Rev. at 7:144 - 9:193.

The Utilities' witness Ms. Hoffman Malueg's direct testimony included a detailed description of how she performed each of the three fundamental steps summarized above and, in particular, the methodologies she used to allocate various categories of costs. Hoffman Malueg Dir., NS Ex. JCHM-1.0 at 8:159 - 24:549; Hoffman Malueg Dir., PGL Ex. JCHM-1.0 Rev. at 7:153 - 25:571. The witness used the Utilities' revenue requirements and rate bases as sources of cost data and drew detailed information from the Utilities' systems or historical books and records. Hoffman Malueg Dir., NS Ex. JCHM-1.0 at 25:551-556; Hoffman Malueg Dir., PGL Ex. JCHM-1.0 Rev. at 25:573-578.

The Utilities' ECOSSs showed the following RORs under present and proposed rates:

| North Shore Gas Company | | |
|---|---|---|
| Service Classification ("S.C.") | Present Rates (rate of return) | Proposed Rates (rate of return) |
| S.C. No. 1 Small Residential Service | 0.77% | 9.18% |
| S. C. No. 2 General Service | 4.30% | 9.18% |
| S. C. No. 3 Large Volume Demand Service | no present customers | 9.18% |
| S. C. No. 5 Standby Service | 5.67% | combined with S. C. No. 2 |
| system average | 1.84% | 9.18% |

Hoffman Malueg Dir., NS Ex. JCHM-1.0 at 35:803 - 36:834. As reflected in the "proposed rates" column and discussed in Section XII(C), *infra*, North Shore's rate design continues to set rates for all its service classifications at cost.

| The Peoples Gas Light and Coke Company | | |
|---|---|---|
| Service Classification ("S.C.") | Present Rates (rate of return) | Proposed Rates (rate of return) |
| S.C. No. 1 Small Residential Service | (0.59%) | 7.29% |

| | | |
|---|---|---|
| S. C. No. 2<br>General Service | 8.02% | 13.27% |
| S. C. No. 4<br>Large Volume Demand Service | 0.83% | 9.34% |
| S. C. No. 6<br>Standby Service | 18.71% | combined with S. C. No. 2 |
| S. C. No. 8<br>Compressed Natural Gas Service | 7.09% | 9.34% |
| system average | 2.53% | 9.34% |

( ) denotes negative number

Hoffman Malueg Dir., PGL Ex. JCHM-1.0 Rev. at 36:844 - 38:874. As reflected in the "proposed rates" column and discussed in Section XII(C), *infra*, Peoples Gas' rate design continues to set rates for S.C. Nos. 4 and 8 at cost, for S.C. No. 1 below cost but less so than in Peoples Gas' last rate case, and for S.C. No. 2 above cost but less so than in the last rate case.

**1. <u>Uncontested Issues</u>**

**a. <u>Sufficiency of ECOSS for Rate Design</u>**

The Utilities' ECOSSs are comprehensive and theoretically sound. The ECOSSs are a reasonable estimate of revenue requirements by customer class and support the rates that the Utilities' rate design witness developed. Hoffman Malueg Dir., NS Ex. JCHM-1.0 at 37:837-839; Hoffman Malueg Dir., PGL Ex. JCHM-1.0 Rev. at 38:877-879. Staff reviewed the Utilities' ECOSSs and concluded that each was an acceptable guidance tool for setting rates. Harden Dir., Staff Ex. 10.0 at 13:246-247; 36:742-743.

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

**a. Classification of Uncollectible Account <u>Expenses Account No. 904</u>**

Account 904 includes uncollectible expenses. In their ECOSSs, the Utilities each functionalized Account 904 costs to the customer function, Customer Accounts category; classified these costs to the Customer category; and allocated these costs based on the "Bad Debt

allocation methodology." Hoffman Malueg Reb., NS-PGL Ex. JCHM-2.0 at 8:158 - 9:171. Under the Bad Debt allocation methodology, the Utilities calculated the average historical bad debt net write-offs per customer by customer class as of the twelve months ended June 30, 2008, and applied that average to the customer counts by customer class for the test year. Hoffman Malueg Dir., NS Ex. JCHM-1.0 at 17:375 - 18:380; Hoffman Malueg Dir., PGL Ex. JCHM-1.0 Rev. at 18:394-399.

The Utilities' functionalization, classification and allocation are proper. For cost classification purposes, Account 904 costs are a function of customers' unpaid bills. The bills' components (fixed or variable; customer or distribution charges) are irrelevant. If a customer does not pay his bill, the unpaid amount becomes an uncollectible account expense, irrespective of the underlying components of the unpaid bill. Hoffman Malueg Reb., NS-PGL Ex. JCHM-2.0 at 9:173-176. Staff's disagreement with the Utilities' treatment of Account 904 costs in their ECOSSs incorrectly mingles cost of service and rate design principles, by relying on the fixed and variable nature of the bill components as a reason for a cost of service study decision. Harden Reb., Staff Ex. 24.0 at 24:515; Harden, Tr. at 952:2-7. Staff agrees that the underlying bill components are a function of rate design and not the ECOSSs. Harden, Tr. at 952:8 - 953:1. As Staff also agrees, the ECOSSs, including cost classification, are used to develop the rate design and not *vice versa*. *Id*. at 951:10-17, 953:2-4. Finally, Staff agrees that the Utilities' ECOSSs witness would not have taken the rate design into account when preparing the ECOSSs. *Id*. at 953:5-8. Consequently, when determining the proper classification of Account 904 costs, the underlying rate design (fixed and variable charges) would not have affected and provides no support for the proper classification.

For allocation purposes, Staff relied on language from the Order in the Utilities' last rate cases to argue that the Utilities should spread these costs according "to the respective demand, customer and commodity classifications by the relative weight or percentage of revenue requirement from each customer class resulting from various categories of costs." Harden Dir., Staff Ex. 10.0 at 3:59 - 4:65. This argument is flawed for several reasons.

First, Staff's recommendation is circular in nature. "Circular" means that one cannot calculate an equation without first having one of its components calculated, but one cannot calculate that component without having the answer to the equation. For example,

Equation: $A = B - C$

Where: $B = A \times D$

One cannot compute the answer to A without knowing the variable B, but one needs to know A in order to compute B. In the context of the Account 904 recommendation, one component of the revenue requirement calculation is operating expenses. Account 904 costs are one piece of operating expenses. Staff's proposal requires determining the revenue requirement by class in order to spread the Account 904 costs to the classes. However, one cannot compute the revenue requirement by customer class without knowing the amount of Account 904 costs allocated to the customer classes. Hoffman Malueg Reb., NS-PGL Ex. JCHM-2.0 at 3:53 - 5:83.

Second, the circular nature of the recommendation means that the Utilities would not be able to implement it through their ECOSSs, *i.e.*, the ECOSSs will not perform the allocation as it would under the Utilities' method. To comply with the 2007 rate case Order, the Utilities "forced" (hard coded) a result into the ECOSSs. Hoffman Malueg Reb., NS-PGL Ex. JCHM-2.0 at 6:116-121. While the Utilities were able to comply with the Order, it was only possible by going outside of the ECOSSs. Grace, Tr. at 184:6 - 185:4.

Third, the Staff witness tried to sidestep the circularity problem by assuming, without support, that the 2007 rate case Order is using the term "revenue requirement" in this context to mean revenue requirement minus the uncollectible expense. Harden Reb., Staff Ex. 24.0 at 23:499-502. The Staff witness agrees, however, that the Order does not include that gloss on the "revenue requirement" definition. Harden, Tr. at 958:8 - 959:8. Moreover, Staff has not explained why such an irregularity -- a unique definition of "revenue requirement" for the sole purpose of the Account 904 costs -- would be proper in building an ECOSSs.

Fourth, other than Peoples Gas and North Shore, there is no evidence that any other Illinois utility uses this approach. The Utilities used this approach in their compliance filings solely due to the requirement in the 2007 rate case Order. Staff agrees that no other Illinois gas utility uses Staff's recommended approach. Hoffman Malueg Reb., NS-PGL Ex. JCHM-2.0 at 7:135-137; NS-PGL Ex. JCHM-2.2; Hoffman Malueg, Tr. at 43:13-18. Staff witness Ms. Harden did not use this approach in either of two cost of service studies that she prepared as a Commission witness, nor did she recommend it in the approximately 15 other rate proceedings in which she was the Commission's main rates witness. Harden, Tr. at 959:9 - 960:5.

Finally, as discussed in Section XII(B)(1), *infra*, Staff's proposal for allocating the rate increase does not allow for determination of the specific amount of Account 904 costs allocated to each service classification.

The Utilities properly classified Account 904 costs as "Customer" costs and used a reasonable approach -- the Bad Debt methodology -- to allocate those costs among customer classes. Staff's recommendation is inconsistent with the cost causation principles that should underlie a cost of service study, improperly mixes cost of service and rate design, and is an anomaly among Illinois utilities.

#### b. Sales Revenues Adjustments

AG-CUB witness Mr. Effron proposed an adjustment (increase) to therm sales for the test year. For the reasons discussed in Section V(C)(8)(a), *supra*, the adjustment is improper. However, were the Commission to accept his proposal, there are several effects on the ECOSSs that Mr. Effron did not address in his incomplete proposal. In particular, his failure to provide a monthly breakdown of the recommended increase to sales means that there was inadequate information to quantify the impact on the ECOSSs revenue requirements by customer class. Hoffman Malueg Sur., NS-PGL Ex. JCHM-3.0 at 6:117-133. In general, his proposal would increase the S.C. Nos. 1 and 2 class revenue requirements and decrease the revenue requirements for other service classifications. Hoffman Malueg Sur., NS-PGL Ex. JCHM-3.0 at 8:171 - 9:182.

## XII. RATE DESIGN

### A. Overview

The Utilities' proposed rate designs were intended to and would accomplish the following seven objectives: (1) recover the Commission-approved revenue requirement; (2) better align revenues with underlying costs; (3) send proper price signals; (4) provide more inter- and intra-class equity; (5) maintain rate design continuity; (6) reflect gradualism; and (7) retain customers on their systems. Grace Dir., NS Ex. VG-1.0 Rev. at 6:111-115; Grace Dir., PGL Ex. VG-1.0 Rev. at 6:112-116.

Each of North Shore's service classifications would continue to be set at its cost of service. Grace Dir., NS Ex. VG-1.0 Rev. at 8:153-154. Peoples Gas' S.C. No. 1 would remain under its cost of service, and S.C. No. 2 would remain over its cost of service, but each by a lesser amount than in the most recent rate cases; and S.C. Nos. 4 and 8 would continue to be set at cost. Grace Dir., PGL Ex. VG-1.0 Rev. at 8:158-164.

The Utilities' rate design proposals are consistent with their existing rate design structure. The Utilities proposed minor modifications to improve the extent to which the rates embody cost causation principles. As examples, the Utilities proposed (1) a new, third meter class for their S.C. No. 2, which will better reflect the costs for the larger usage customers expected to be served under this meter class; (2) eliminating their standby service classifications, as these customers are more logically placed on the general service classification; and (3) including usage-based eligibility criterion for each of the general service and large volume demand service classifications. These proposals are described in Section XII(C), *infra*, and are uncontested.

The principal contested rate design issues are how the rate increase will be allocated and the amount of S.C. Nos. 1 and 2 fixed costs to be recovered through fixed charges. The Account 904 issue described in connection with the ECOSSs has a rate design counterpart. Finally, there is an untested and flawed S.C. No. 1 rate design proposal at issue. For these issues, the Utilities demonstrated that their proposals are appropriate and should be approved.

## B. General Rate Design

### 1. Allocation of Rate Increase

Coupled with the Utilities' ECOSSs, the descriptions of the Utilities' rate design, including the supporting exhibits, are detailed and specific enough that it would be straightforward to derive rates from whatever revenue requirement the Commission approves. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 5:85-87. This is not the case for the Staff proposals. It is also not the case for the AG-CUB-City tiered rate proposal, which, in any event, only applies to S.C. No. 1.

Staff witness Ms. Harden included proposed rates and exhibits with her rebuttal testimony. Harden Reb., Staff Ex. 24.0, Scheds. 24.1N (Corr.) and 24.1P (Corr.). There are

several flaws with the rates, and the testimony and exhibits would not be suitable or sufficient for developing final rates.

Staff's approach takes a ratio of its proposed revenue requirement to each of the Utilities' proposed revenue requirements and applies it, uniformly, to each of the Utilities' proposed rates. This is flawed for several reasons. Briefly, it is not based upon cost of service principles. The electronic format of the exhibits has conceptual problems and formulaic errors. Some of the formulas and outcomes are inconsistent with Staff's testimony. Grace Sur., NS-PGL Ex. VG-3.0 at 9:191-197.

First, Staff's method is not based upon costs or revenue requirements arising from an embedded cost of service study. It ignores the cost differences and cost allocations between rate classes and assumes that all Staff-proposed adjustments could be equally applied to customer, demand, and commodity related costs, although those adjustments were specific and not derived on an across the board basis. Adjustments affecting rate base and expense items are treated equally and grouped together in one revenue requirement number, without considering the type of costs affected by each adjustment. It also ignores Account specific costs and would make it impossible to render Account specific adjustments for certain rates. For example, the Utilities' witness and Staff witness Mr. Sackett agreed that it would be appropriate to remove Account 304 ("Land and Land Rights") costs from the standby service charge. Staff's rates approach would not allow that change. Also, it would not allow the Utilities to properly reflect final Account 904 costs arising from updated gas costs or any other relevant factors that the Commission may order in this proceeding. *Id*. at 9:200 - 10:216.

Second, Staff's method improperly adjusts: charges that the Utilities did not propose to change; charges based on specific cost-based revenue requirement components; and cost-based

charges based on expenses that would be unaffected by Staff's proposed adjustments. There is no record support for these changes. For example, the Utilities did not propose to revise their Second Pulse or Rider SBO, Supplier Billing Option Service, charges, yet Staff's exhibit adjusts those charges. The Utilities proposed to set their standby service charges based on the Production and Storage revenue requirements arising from their ECOSSs, along with an Account 304 adjustment. Staff's approach is inconsistent with those facts. The Utilities proposed changes to various cost-based transportation service administrative charges. These charges are based on a specific cost study (Section XIII(B)(2) *infra*), which Staff did not contest, yet Staff's approach would change these charges. *Id*. at 10:219 - 11:234.

Considering individual service classifications, the general problems identified above are multiplied. For example,

- Staff supported (Harden Dir., Staff Ex. 10.0 at 36:737-739), but did not apply, Peoples Gas' proposed equal percentage of embedded cost methodology for S.C. Nos. 1 and 2. Instead, Staff applied its uniform adjustment to the embedded customer charge (although stating that the adjustment was to the allocated customer charge).
- Staff did not accommodate the sales adjustment proposed by AG-CUB witness Mr. Effron, which Staff supports in principle (Harden Reb., Staff Ex. 24.0 at 20:422-427), that would shift costs caused by additional S.C. Nos. 1 and 2 sales quantities to S.C. Nos. 1 and 2, respectively.
- Despite Staff's lower proposed revenue requirement, Staff's method would result, without explanation or support, in a proposed S.C. No. 2 meter class 3 customer charge that is 78% higher than Peoples Gas' proposal.

- Staff's proposed S.C. Nos. 1 and 2 rates would result in higher distribution charges arising from Staff's proposed lower customer charges. The testimony included no bill impacts for this change.
- North Shore's S.C. No. 3 and Peoples Gas' S.C. No. 4 are both set at cost based upon their ECOSSs. Uniform rate adjustments do not take that into consideration and could result in these service classifications being either above or below cost, with the magnitude being determined by a mathematical exercise rather than the ECOSSs. This would affect the Utilities' next rate cases.
- There is no way to determine the specific amount of total Account 904 costs allocated to each service classification and each service type (sales or transportation).
- For Peoples Gas, Staff's approach shifts too much gas cost-related Account 904 costs to S.C. No. 1 and not enough to S.C. No. 2. In particular, Staff's approach shifts too much of such costs to Peoples Gas' S.C. No. 1 sales customers and, apparently, none to S.C. No. 1 transportation customers although a small amount of gas cost related Account 904 costs should be allocated to them.
- For North Shore, Staff's approach shifts too little gas cost-related Account 904 costs to S.C. No. 1 and too much to S.C. No. 2.

Grace Sur., NS-PGL Ex. VG-3.0 at 12:249 - 19:423. Only the Utilities have proposed ECOSSs and rate designs with the requisite specificity to derive rates from whatever revenue requirements and rate designs that the Commission orders.

### 2. Account 904 Uncollectible Expense

The Utilities proposed different customer charges for transportation and sales customers. Differentiation is proper as a matter of cost causation, *i.e.*, costs should be allocated to those who cause the utility to incur the costs. Hoffman Malueg Dir., NS Ex. JCHM-1.0 at 7:152-156; Hoffman Malueg Dir., PGL Ex. JCHM-1.0 Rev. at 7:146-150. When a sales customer does not pay his bill, part of that bill includes gas purchased from the utility. When a transportation customer does not pay his bill, that is not the case. Rubin, Tr. at 973:2-21. Consequently, the gas cost-related Account 904 expense associated with sales and transportation customers differs and should be recognized in rates. Currently, this differential is reflected in the distribution charges. There are two major reasons why differentiation in the customer charge is the better rate design. Grace Dir., NS Ex. VG-1.0 Rev. at 11:236 - 12:254; Grace Dir., PGL Ex. VG-1.0 Rev. at 12:266 - 13:284.

First, for the reasons stated in Section XI(B)(2)(a), *supra*, the ECOSSs properly classified Account 904 costs as "customer" costs. Consequently, the rate design developed from the ECOSSs should address Account 904 responsibility in the customer charge. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 5:99-102. Ideally, the customer charge would include all costs classified as customer costs. However, for S.C. No. 1, in the interest of gradualism, the Utilities set their customer charges below the embedded customer costs. Grace Dir., NS Ex. VG-1.0 Rev. at 13:270-271; Grace Dir., PGL Ex. VG-1.0 Rev. at 14:304-306. For S.C. No. 2, meter classes 1 and 2, all customer costs are recovered through the customer charge, but in the interests of gradualism, less than all customer costs would be recovered through the meter class 3 customer charge. Grace Dir., NS Ex. VG-1.0 Rev. at 18:382-390; Grace Dir., PGL Ex. VG-1.0 Rev. at 19:419 - 20:427.

Second, customer charge differentiation better addresses customer migration from sales to transportation service and *vice versa*. When a customer moves from one service to the other, the customer charge differentiation means that the gas cost-related Account 904 expense moves with the customer. Grace Dir., NS Ex. VG-1.0 Rev. at 12:249-254; Grace Dir., PGL Ex. VG-1.0 Rev. at 13:279-284.

Customer migration also raises two practical considerations that differentiation in the customer charge can easily address. Adjustments under the Utilities' decoupling mechanism, Rider VBA, are based on rate case margins, which means that distribution revenues drive the calculation. Setting rates with differentiation in the distribution charges means that, when customers move between sales and transportation service, the resulting distribution revenues (actual margins) are skewed from the rate case margins more than would be the case were the differentiation in the customer charge. Consequently, Rider VBA adjustments are greater than would otherwise be the case. Moreover, differentiation in the distribution charges means that there are different Rider VBA rate case margin baselines for sales and transportation customers and, consequently, different Rider VBA adjustments for sales and transportation customers. While this has no impact whatsoever on the accuracy of the Rider VBA adjustments, it does unnecessarily require four, instead of two, adjustments (S.C. No. 1 sales and transportation and S.C. No. 2 sales and transportation). Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 6:106 - 7:138.

In addition, among the problems associated with Staff's proposal for allocating the rate increase (*see* Section XII(B)(1), *supra*) are apparent errors with Account 904 cost allocation.

Were the Commission to accept Staff's proposal for treatment of Account 904 costs in the ECOSSs, it would still be proper to differentiate for the gas cost-related Account 904 expense in the customer charge. Even under Staff's theory, the largely fixed revenue requirement would

be the basis for the Account 904 cost allocation, so most costs would be allocated as fixed costs. Consequently, allocation to the fixed customer charge is reasonable under the Utilities' and the Staff's approach. Grace Sur., NS-PGL Ex. VG-3.0 at 7:138-145.

In sum, differentiation in the customer charges for sales and transportation customers to adjust for gas cost-related Account 904 expense is the result that properly flows from classifying the Account 904 costs as "customer" costs. This rate design best reflects cost causation principles, and, for that reason alone, it should be approved. Moreover, an ancillary benefit is halving the number of Rider VBA adjustments and eliminating the sales and transportation distinction in those adjustments.

#### 3. Uniform Numbering of Service Classifications

Staff proposed that the Utilities adopt uniform numbering for their service classifications. For example, S.C. No. 1 for each company is Small Residential Service, but the Large Volume Demand Service is S.C. No. 3 for North Shore and S.C. No. 4 for Peoples Gas. Harden Dir., Staff Ex. 10.0 at 10:195 - 12:228. The Utilities agreed to assess their customer information systems to determine if they can implement uniform numbering in their next rate cases. Grace Sur., NS-PGL Ex. VG-3.0 at 9:183-186.

### C. Service Classification Rate Design

#### 1. Uncontested Issues

##### a. North Shore Service Classification Nos. 2 and 3 Eligibility Criterion

North Shore proposed an eligibility criterion for each of S.C. Nos. 2, General Service, and 3, Large Volume Demand Service. S.C. No. 2 would be available to customers who consume an average of 41,000 monthly therms or less. S.C. No. 3 would be available to customers who consume a monthly average of more than 41,000 therms. North Shore would

determine eligibility annually, using data from the most recent two calendar year period. Grace Dir., NS Ex. VG-1.0 Rev. at 10:210-213. Adding such a requirement to S.C. Nos. 2 and 3 ensures that customers are served under the rate classes for which North Shore derived costs and charges. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 42:937 - 43:947, 44:977-981.

Only Staff witness Mr. Sackett addressed this proposal. He concluded that North Shore's arguments were reasonable and recommended that the Commission approve the proposal. Sackett Reb., Staff Ex. 26.0 at 4:80-87.

**b. <u>North Shore Service Classification No. 3</u>**

S.C. No. 3 is North Shore's Large Volume Demand Service. North Shore proposed setting this classification at cost to help meet its objective of maintaining customers on the system. It proposed changing the demand charge from a declining block to a flat rate to mitigate the impact on customers who migrate to S.C. No. 3 from S.C. No. 2 and setting it at 67% of cost; increasing the customer charge, setting it at cost; revising the standby service charge and removing Account 304 costs; increasing the distribution charge; and eliminating the written contract requirement. The rates are the same for sales and transportation customers. Grace Dir., NS Ex. VG-1.0 Rev. at 10:203-210, 21:454 - 22:484; Sackett Reb., Staff Ex. 26.0 at 45:911-914.

Only Staff addressed the proposal. Ms. Harden recommended approval of the various aspects of North Shore's proposed rate design. Harden Dir., Staff Ex. 10.0 at 25:494 - 29:598. Mr. Sackett concurred that the removal of Account 304 costs from the standby service charge was appropriate. Sackett Reb., Staff Ex. 26.0 at 45:916-919.

**c. <u>North Shore Service Classification No. 5</u>**

North Shore proposed to eliminate its S.C. No. 5, Standby Service, and transfer customers to S.C. No. 2. Other than using gas for standby service, the S.C. No. 5 customers have

no similar usage or cost characteristics. Consequently, it is more appropriate to serve these customers under a general service rate. Grace Dir., NS Ex. VG-1.0 Rev. at 23:487-491.

Only Staff addressed this proposal. Ms. Harden concluded that the proposal was appropriate. Harden Dir., Staff Ex. 10.0 at 32:650-657.

**d. North Shore Service Classification No. 6**

North Shore proposed no changes to S.C. No. 6, Contract Service for Electric Generation. Grace Dir., NS Ex. VG-1.0 Rev. at 23:493-495. Staff witness Ms. Harden noted that there are currently no customers served under this service classification, and she proposed no changes. Harden Dir., Staff Ex. 10.0 at 32:660 - 33:663. No other party opposed it.

**e. Peoples Gas Use of Equal Percentage of Embedded Cost Method ("EPECM")**

Peoples Gas proposed to use the equal percentage of embedded cost method ("EPECM") to allocate the additional revenue requirement between S.C. Nos. 1 and 2. Peoples Gas used and the Commission approved the EPECM in its last three rate cases (Docket Nos. 91-0586, 95-0032 and 07-0242). The ECOSSs showed that rates for S.C. Nos. 1, 2, 4 and 8 were below cost. Peoples Gas proposed to move S.C. Nos. 4 and 8 to cost but to use the EPECM to move S.C. Nos. 1 and 2 gradually toward cost. Using the EPECM, Peoples Gas allocates the increase in proportion to the embedded cost of service for these two service classifications. S. C. No. 1 would be set below cost, but less so than under rates set in the last rate case. S.C. No. 2 would be set above cost, but less so than under the rates set in the last rate case. Grace Dir., PGL Ex. VG-1.0 Rev. at 8:156 - 9:191.

Only Staff addressed this proposal. Staff agreed that using the EPECM was appropriate and helps to mitigate the bill impact on small residential customers. Harden Dir., Staff Ex. 10.0 at 36:737-739. No other party opposed it.

### f. Peoples Gas Service Classification Nos. 2 and 4 Eligibility Criterion

Peoples Gas proposed a new eligibility criterion for S.C. No. 2, General Service, and proposed no changes to its current eligibility criterion for S.C. No. 4, Large Volume Demand Service. S.C. No. 2 would be available to customers who consume an average of 41,000 monthly therms or less. S.C. No. 4 would remain available to customers who consume an average of more than 41,000 monthly therms. Peoples Gas would determine eligibility annually, using data from the most recent two calendar year period. Grace Dir., PGL Ex. VG-1.0 Rev. at 11:238-241. Adding an eligibility requirement to S.C. No. 2 that mirrors the existing S.C. No. 4 requirement ensures that customers are served under the rate classes for which Peoples Gas derived costs and charges. Grace Reb., NS-PGL Ex. VG-2.0 Rev. 42:937 - 44:974.

Only Staff addressed this proposal. He concluded that Peoples Gas' arguments were reasonable and recommended that the Commission approve the proposal. Sackett Reb., Staff Ex. 26.0 at 4:80-87. No other party opposed it.

### g. Peoples Gas Service Classification No. 4

S.C. No. 4 is Peoples Gas' Large Volume Demand Service. Peoples Gas proposed setting this service classification at cost to help meet its objective of maintaining customers on the system. It proposed changing the demand charge from a declining block to a flat rate to mitigate the impact on customers who migrate to S.C. No. 4 from S.C. No. 2 and setting the charge at 55% of cost; increasing the customer charge, setting it at cost; revising the standby service charge and removing Account 304 costs; increasing the distribution charge; and eliminating the written contract requirement. The rates are the same for sales and transportation customers. Grace Dir., PGL Ex. VG-1.0 Rev. at 11:242 - 12:247, 22:491 - 24:531; Sackett Reb., Staff Ex. 26.0 at 45:911-914.

Only Staff addressed this proposal. Ms. Harden recommended approval of the various aspects of Peoples Gas' proposed rate design. Harden Dir., Staff Ex. 10.0 at 48:994 - 53:1098. Mr. Sackett concurred that the removal of Account 304 costs from the standby service charge was appropriate. Sackett Reb., Staff Ex. 26.0 at 45:916-919. No other party opposed it.

**h. <u>Peoples Gas Service Classification No. 5</u>**

Peoples Gas proposed no changes to S.C. No. 5, Contract Service for Electric Generation. Grace Dir., PGL Ex. VG-1.0 Rev. at 25:545-547. Staff witness Ms. Harden noted that there are currently no customers served under this service classification, and she proposed no changes. Harden Dir., Staff Ex. 10.0 at 53:1101 - 54:1104.

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

Peoples Gas proposed to eliminate its S.C. No. 6, Standby Service, and transfer customers to S.C. No. 2. Peoples Gas explained that, other than using gas for standby service, the customers served under S.C. No. 6 have no similar usage or cost characteristics. Consequently, it is more appropriate to serve these customers under a general service rate. Grace Dir., PGL Ex. VG-1.0 Rev. at 24:533-538.

Only Staff addressed this proposal. Ms. Harden concluded that the proposal was appropriate. Harden Dir., Staff Ex. 10.0 at 54:1107 - 57:1170. No other party opposed it.

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

Peoples Gas proposed to set S.C. No. 8, Compressed Natural Gas Service, at cost. The customer charge would decrease and the distribution charge would increase. Grace Dir., PGL Ex. VG-1.0 Rev. at 25:540-543.

Only Staff addressed this proposal. Ms. Harden concluded that the proposal was appropriate. Harden Dir., Staff Ex. 10.0 at 57:1173 - 58:1205. No other party opposed it.

### 2. Contested Issues

#### a. North Shore Service Classification No. 1

##### i. Account 904

North Shore proposed to set different S.C. No. 1 customer charges for sales and transportation customers. Currently, there are different distribution charges. The reason for the different charges is that the rates for transportation customers, who purchase their gas from suppliers other than the Utilities, would not include the gas cost-related Account 904 expense. The reason for and the appropriateness of North Shore's approach is detailed in Section XII(B)(2), *supra*.

##### ii. North Shore's Rate Design

North Shore's S.C. No. 1 would be set at cost. North Shore proposed to increase its customer charge, and it would recover only 55% of fixed costs. The distribution charges would continue to be in the form of a declining two block rate with the first block (0 to 50 therms) recovering two-thirds of demand, commodity and remaining customer costs and the second block (over 50 therms) recovering the remaining costs. Grace Dir., NS Ex. VG-1.0 Rev. at 12:255 - 14:290.

##### iii. Customer Charge

North Shore's proposal to increase the customer charge is consistent with prior cases in which the Commission encouraged or approved rate designs that reflect greater recovery of fixed costs in the customer charge. Grace Dir., NS Ex. VG-1.0 Rev. at 14:306 - 15:325. In Peoples Gas' 1995 rate case, the Commission, in approving the proposed customer charge, stated that it "in fact, should be increased in future rate proceedings to move it closer to cost." *In re The Peoples Gas Light and Coke Company*, ICC Docket No. 95-0032 (Order, Nov. 8, 1995). In North Shore's last rate case, the Commission approved an increase in fixed cost recovery

through the customer charge to 50% of the S. C. No. 1 revenue requirement. *Peoples 2007* at 269. For Nicor, the Commission approved recovery of 80% of fixed costs through the customer charge. The Commission stated that "[m]oving a greater percentage of fixed cost recovery to fixed charges rather than volumetric charges provides a more stable revenue stream and sends a better price signal to the consumer." *Nicor 2008* at 91.

Staff contends that there should be no increase in the amount of fixed costs recovered through the customer charge because this would be a "mid-stream alteration to the design of the [Rider VBA] program." Harden Reb., Staff Ex. 24.0 at 7:138-140. This reasoning is flawed.

First, nothing in the Commission's order approving Rider VBA (*Peoples 2007*) states or suggests that rate design could not change while Rider VBA is in effect. Indeed, Rider VBA will not change, although, as Staff agrees (Hathhorn Dir., Staff Ex. 1.0 at 44:1041 - 45:1056) the rate case margins, a factor in the Rider VBA adjustment calculation, must change.

Second, the proposed customer charges for the service classifications to which Rider VBA applies (S.C. Nos. 1 and 2) remain far below embedded fixed costs. For Peoples Gas, only about 48% of fixed costs would be recovered through fixed charges, which leaves nearly $300 million subject to Rider VBA. For North Shore, only about 56% of fixed costs would be recovered through fixed charges, which leaves nearly $40 million subject to Rider VBA. These are large dollar amounts that the Utilities recover through variable charges and that will factor into the Rider VBA adjustments. Significant activity will remain under Rider VBA for purposes of reviewing its effect. Grace Reb., NS-PGL Ex. VG-2.0 Rev at 9:183-190.

Third, the Commission approved Rider VBA only as a pilot program, and it will terminate in March 2012, unless the Utilities request and the Commission approves an extension. *Peoples 2007* at 152. For the affected service classifications, Peoples Gas has only about

$15 million in variable costs and North Shore only about $695,000, although significantly larger amounts of fixed costs are recovered through variable charges. If Rider VBA ends, the Utilities would still have a very large amount of fixed costs to be recovered through variable charges. (Even the Utilities' proposal puts only a small dent in this mismatch.) Under Staff's theory, the Utilities could take no steps to mitigate this circumstance during the four years that Rider VBA is in effect, despite the Commission's policy encouraging fixed cost recovery through fixed charges. Grace Reb., NS-PGL Ex. VG-2.0 Rev at 9:190-198.

North Shore's customer charge should be set to recover at least 55% of fixed costs.

**iv. <u>Tiered Rates</u>**

AG-CUB-City witness Mr. Rubin proposed what he called "tiered rates." His proposal would set seven tiers of flat monthly charges based on a customer's annual usage, determined over an historical two-year period. Rubin Dir., AG-CUB-City Ex. 2.0 28:553-555; 38:744-745. There are sound reasons why tiered rates have not been used for energy companies. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 21:453-468. The proposal in these proceedings is conceptually and practically flawed. *Id*. at 13:285 - 35:776.

Conceptual flaws with the proposal include that:

- it does not normalize the historical data on which placement in tiers would be based, which can cause the utility to under- or over-earn its revenue requirement. For example, the data that Mr. Rubin used for setting his proposed rates were for a period that was colder than normal. Consequently, relative to normal, he used overstated usage and volumetric revenues.

- it does not take changing customer usage into account. The record shows that, for several reasons, customer usage has been declining. Mr. Rubin used data from mid-2007 through mid-2008 that do not take that fact into account.
- it bases proposed rates on an incomplete data set and a simplistic mathematical extrapolation for many customers. The historical data Mr. Rubin used for Peoples Gas included only 69% of total customers, which means that he assigned almost 239,000 customers to tiers with no usage data for those customers. For North Shore, the comparable figure is 46,000 customers.
- the number and range of the tiers is not fully explained. There are seven total tiers. Some tiers span 500 therms. Two tiers each span 1,500 therms. The last tier is for customers with usage over 5,000 therms. There are no apparent rate design principles underlying the tiers.

*Id*. at 13:285 -18:392.

Practical problems with the proposal include that:

- it includes only one set of rates but it would need distinct rates for sales and transportation customers to address gas cost-related Account 904 expenses. Cost causation principles support rate differentiation. Mr. Rubin did not develop distinct rates, nor address the mechanics of developing and implementing distinct rates.
- it would require substantial modifications to the Utilities' customer information systems to track usage and apply the tiers to the Utilities' over 900,000 S.C. No. 1 customers. The proposed rates do not include the costs associated with these

modifications, nor do they take into account any transition period needed to develop, test and implement the modifications.

- there are many challenges to placing in tiers customers with less than one year's usage, such as new customers (which may mean the same person with a new account number), customers with gas theft, or customers with other deficiencies with their historical usage.
- customer disputes about tier placement would raise novel issues for which there are no ready answers.
- sales revenue forecasting would be complicated.

*Id*. at 18:393 - 20:450.

The tiered rate proposal should be rejected due to the many conceptual and practical problems detailed in the record and briefly summarized above.

**b. <u>North Shore Service Classification No. 2, Customer Charge</u>**

North Shore proposed to add an additional meter class (meter class 3) to S.C. No. 2. It then proposed to increase the customer charges and move the charges for all three meter classes closer to cost. For the same reasons discussed in connection with S.C. No. 1 (Section XII(C)(2)(a)(i), *supra*), there would be different customer charges for sales and transportation customers to reflect differentiation for gas cost related Account 904 expenses. For meter classes 1 and 2, North Shore would recover all customer costs and a portion of demand costs in the customer charge. For meter class 3, only 18% of demand costs would be recovered through the customer charge, in the interest of gradualism. This directly affects the distribution charges in the declining three block structure. The remaining costs would be allocated to the distribution blocks, and, for the first two blocks, this would be a decrease because of the

proposed increase to the customer charge. However, because the new meter class 3 customer charge has fewer fixed costs included, the third block of the distribution charges would increase. Only 54% of the S.C. No. 2 revenue requirement would be recovered under fixed charges. Grace Dir., NS Ex. VG-1.0 Rev. at 17:362 - 19:407.

Staff contends that there should be no increase in the amount of fixed costs recovered through the customer charge because this would be a "mid-stream alteration to the design of the [Rider VBA] program." Harden Reb., Staff Ex. 24.0 at 7:138-140. For the reasons set forth in Section XII(C)(2)(a)(iii), *supra*, in connection with the S.C. No. 1 customer charge, Staff's proposal to not increase fixed cost recovery should be rejected.

**c. <u>Peoples Gas Service Classification No. 1</u>**

**i. <u>Account 904</u>**

Like North Shore and for the same reasons, Peoples Gas proposed different S.C. No. 1 customer charges for sales and transportation customers. Grace Dir., PGL Ex. VG-1.0 Rev. at 13:285 - 15:325. *See* Section XII(C)(2)(a)(i), *supra*.

**ii. <u>Peoples Gas' Rate Design</u>**

Peoples Gas proposed to increase its customer charges. Peoples Gas' S.C. No. 1 rates would be set below cost. The customer charge would recover less than the embedded customer costs and would be set to recover 54% of fixed costs. The distribution charges would continue to be in the form of a declining two block rate with the first block (0 to 50 therms) recovering 65% of demand, commodity and remaining customer costs and the second block (over 50 therms) recovering the remaining costs. Grace Dir., PGL Ex. VG-1.0 Rev. at 13:285 - 15:325.

#### iii. Customer Charge

Like North Shore's proposal and for the same reasons, Peoples Gas' proposal to increase the customer charge is consistent with prior cases in which the Commission encouraged or approved rate designs that reflect greater recovery of fixed costs in the customer charge. Grace Dir., PGL Ex. VG-1.0 Rev. at 16:339 - 17:360. *See* Section XII(C)(2)(a)(iii), *supra*. Peoples Gas' customer charge should be set to recover at least 54% of fixed costs.

#### iv. Tiered Rates

For the reasons stated in Section XII(C)(2)(a)(iv), *supra*, AG-CUB-City witness Mr. Rubin's tiered rate proposal is conceptually and practically flawed and should be rejected.

### d. Peoples Gas Service Classification No. 2, Customer Charge

Peoples Gas proposed to add an additional meter class (meter class 3) to S.C. No. 2. It then proposed to increase the customer charges and move the charges for all three meter classes closer to cost. For the same reasons discussed in connection with S.C. No. 1 (Sections XII(C)(2)(a)(i) and XII(C)(2)(c)(i), *supra*), sales and transportation customers would have different customer charges to reflect differentiation for gas cost related Account 904 expenses. For meter classes 1 and 2, Peoples Gas would recover all customer costs and a portion (20%) of demand costs in the customer charge. For meter class 3, it would recover no demand costs in the customer charge, in the interest of gradualism. This directly affects the distribution charges in the declining three block structure. The remaining costs would be allocated to the distribution blocks. The charges for all three blocks would increase, but the increase for the third block would be larger, which results from the fact that no demand costs would be recovered through the meter class 3 customer charge. Only 35% of the S.C. No. 2 revenue requirement would be recovered under fixed charges. Grace Dir., PGL Ex. VG-1.0 Rev. at 18:397 - 20:443.

Although Staff's rate proposals in its rebuttal testimony results an overall increase in fixed cost recovery as well as for S.C. No. 2, Staff contends that there should be no increase in the amount of fixed costs recovered through the customer charge because this would be a "mid-stream alteration to the design of the [Rider VBA] program." Harden Reb., Staff Ex. 24.0 at 7:138-140. Grace Sur., NS-PGL Ex. VG-3.0 at 7:156-159. Grace Sur., NS-PGL Ex. VG-3.0 at 14:300-301. For the reasons set forth in Sections XII(C)(2)(a)(iii) and XII(C)(2)(c)(iii), *supra*, in connection with the S.C. No. 1 customer charge, Staff's proposal to not increase fixed cost recovery should be rejected.

## D. Tariffs – Other Tariff Issues

### 1. Uncontested Issues – North Shore and Peoples Gas

#### a. General Terms and Conditions

The Utilities each proposed several changes to their Terms and Conditions of Service. Those changes are: (1) revise the service activation and reconnection charges (discussed in subsections (b) and (c), *infra*); (2) insert a specific date for grandfathering the second pulse charge; (3) revise language related to the "Correction for Pressure, Temperature and/or Supercompressibility" for consistency with the Utilities' practices concerning the pressure at which customers are served; (4) add a definition of "person" related to changes to Riders 4 and 5 (discussed in subsection (g) *infra*); and (5) eliminate Peoples Gas' Facilities Charge (discussed in subsection (h) *infra*). Grace Dir., NS Ex. VG-1.0 Rev. at 28:602-612; Grace Dir., PGL Ex. VG-1.0 Rev. at 30:657-669.

As shown below, Staff generally supported these proposals. No party opposed them.

### b. Service Activation Charges

North Shore performs two types of service activation: succession turn-on when a customer moving out discontinues gas service at approximately the same time as a new applicant requests service; and a straight turn-on when there has never been service at a premises or there has been a longer time lapse between customers. North Shore performed a cost study (NS Ex. VG-1.9) showing that the cost: for a succession turn-on is $16.59 and proposed to charge $16.50; for a straight turn-on is $43.91 and proposed to charge $35; and for lighting each appliance in excess of four is $8.91 and proposed no change to its current $5 charge. Grace Dir., NS Ex. VG-1.0 Rev. at 24:509-526; Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 49:1090-1095.

Peoples Gas performs the same types of service activations. Its cost study (PGL Ex. VG-1.9) showed the cost: for a succession turn-on is $15.52 and proposed to charge $15; for a straight turn-on is $47.78 and proposed to charge $25; and for lighting each appliance in excess of four is $10.67 and proposed no change to its current $5 charge. Grace Dir., PGL Ex. VG-1.0 Rev. at 26:561-579.

Staff witness Mr. Boggs reviewed the proposed charges, and he recommended their approval. He also recommended that, in future rate cases, the Utilities should move steadily to full cost recovery from the customers who cause these expenses. Boggs Dir., Staff Ex. 11.0 at 3:49 - 8:141, 25:500 - 28:569; Staff Ex. 25.0 at 2:23-24.

### c. Service Reconnection Charges

North Shore performs three types of service reconnection: basic reconnection requiring only a meter turn-on; reconnections requiring setting a new meter; and reconnections at the main. North Shore performed a cost study (NS Ex. VG-1.9) showing that the cost: for a reconnection at the meter is $65.88 and proposed to charge $60; for a reconnection when the meter is reset is

$256.04 and proposed to charge $125; and for a reconnection at the main is $1,988.89 and proposed to charge $350. The cost to light additional appliances is the same as for the activation charge, discussed in subsection (b) *supra*, and North Shore proposed no change to the current $5 per appliance in excess of four charge. Grace Dir., NS Ex. VG-1.0 Rev at 24:528 - 25:550.

Peoples Gas performs the same three types of service reconnection, and it also preformed a cost study (PGL Ex. VG-1.9). The study showed that the cost: for a reconnection at the meter is $78.59 and proposed to charge $60; for a reconnection when the meter is reset is $228.91 and proposed to charge $125; and for a reconnection at the main is $2,189.49 and proposed to charge $350. The cost to light additional appliances is the same as for the activation charge, discussed in subsection (b) *supra*, and Peoples Gas proposed no change to the current $5 per appliance in excess of four charge. Grace Dir., PGL Ex. VG-1.0 Rev. at 26:581 - 27:603.

Staff witness Mr. Boggs reviewed the proposed charges, and he recommended their approval. He also recommended that, in future rate cases, the Utilities should move steadily to full cost recovery from the customers who cause these expenses. Boggs Dir., Staff Ex. 11.0 at 8:143 - 12:220, 28:571 - 32:651.

**d. <u>Second Pulse Capability</u>**

The Utilities proposed no change to the $14 monthly second pulse capability charge. Grace Dir., NS Ex. VG-1.0 Rev. at 28:606-608; NS Ex. VG-1.1 at 10; Grace Dir., PGL Ex. VG-1.0 Rev. at 30:661-663; PGL Ex. VG-1.1 at 12. Second pulse capability is an optional service and involves measurement devices that can provide real time usage data to customers. The charge does not apply to those who had the capability installed prior to February 14, 2008 (the effective date of the Utilities' 2007 rate cases). Staff supported the wording change to add this date. Boggs Dir., Staff Ex. 11.0 at 12:229 - 13:249.

#### e. Rider 1

The Utilities proposed editorial changes to Rider 1, Additional Charges for Taxes and Customer Charge Adjustments, to clarify the rider. NS Ex. VG-1.1 at 16; PGL Ex. VG-1.1 at 19. Staff recommended approval. Boggs Dir., Staff Ex. 11.0 at 14:267 - 15:289, 37:743-750.

#### f. Rider 2

The Utilities proposed several editorial changes to Rider 2, Gas Charge, to clarify the rider. They deleted references to riders and service classifications that they propose to delete and, for Peoples Gas, eliminated a date reference that is no longer needed. Grace Dir., NS Ex. VG-1.0 Rev. at 28:614-616; Grace Dir., PGL Ex. VG-1.0 Rev. at 31:691-694. Staff recommended approval of the changes, if the Commission approves elimination of the referenced tariffs. Boggs Dir., Staff Ex. 11.0 at 15:291 - 16:306, 38:763-766. Neither Staff nor any party opposed removal of the referenced tariffs (*see* Section XIII(B)(1), *infra*).

#### g. Riders 4 and 5

The Utilities proposed revisions to Rider 4, Extension of Mains, and Rider 5, Service Pipe, to accommodate situations where the person or group of persons requesting the main or service is developing the property for future gas service and is not the applicant for service. Grace Dir., NS Ex. VG-1.0 Rev. at 28:618 - 29:624; Grace Dir., PGL Ex. VG-1.0 Rev. at 32:696-702. Staff agreed. Boggs Dir., Staff Ex. 11.0 at 16:308 - 19:385; 38:768 - 41:841.

#### h. Account 385 Facilities Charge

Peoples Gas proposed to eliminate the Facilities Charge. In its 2007 rate case, the Commission ordered Peoples Gas to directly bill customers served by large meters that are classified under Account 385 ("Industrial Measuring and Regulating Station Equipment"). This approach is no longer needed for two reasons.

First, subsequent to its last rate case, Peoples Gas changed certain accounting policies that resulted in 781 customer accounts being reclassified under Account 385, which far exceeds the number when the Commission issued the *Peoples 2007* Order. Second, Peoples Gas is proposing a meter class 3 for its S.C. No. 2 that would better assign the Account 385 costs. Grace Dir., PGL Ex. VG-1.0 Rev. at 31:672-689; Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 50:1100-1107. Staff agreed that the charge should be eliminated. Boggs Dir., Staff Ex. 11.0 at 36:733-739; Staff Ex. 25.0 at 2:26 - 3:47.

### 2. Volume Balancing Adjustment (Rider VBA)

The Commission approved decoupling mechanisms (Rider VBA, Volume Balancing Adjustment) for the Utilities in the 2007 cases. Rider VBA is in effect for a four-year pilot period that will end with the March 2012 filing unless the Utilities request and receive approval to make it permanent. *Peoples 2007* at 152. The Utilities proposed no changes to Rider VBA in the instant cases, but the "rate case margins" ("RCM") components of the calculation will change. Grace Dir., NS Ex. VG-1.0 Rev. at 14:291-298, 19:421 - 20:428; Grace Dir., PGL Ex. VG-1.0 Rev. at 15:326-333, 21:457-464. As of the filing, for the period May 2008 through February 2009, North Shore had refunded $475,000 to S.C. No. 1 customers and $397,000 to S.C. No. 2 customers. Grace Dir., NS Ex. VG-1.0 Rev. at 14:301-303, 20:431-433. For Peoples Gas, the refunded amounts were $1.7 million to S.C. No. 1 customers and $2.3 million to S.C. No. 2 customers. Grace Dir., PGL Ex. VG-1.0 Rev. at 16:336-338, 21:467-469.

#### a. Establishment of New Margins

When new rates are set in these proceedings, the RCMs will change. If the Commission accepts the Utilities' proposal to differentiate for Account 904 costs in the customer charge, there will be a new RCM for each of S.C. Nos. 1 and 2. If the Commission requires differentiation

through the distribution charge, then there will be four new RCMs, namely, a sales RCM and a transportation RCM for each of S.C. Nos. 1 and 2. Grace Dir., NS Ex. VG-1.0 Rev. at 14:291-298, 19:421 - 20:428; Grace Dir., PGL Ex. VG-1.0 Rev. at 15:326-333, 21:457-464. The Utilities provided, in data responses, the revised RCMs, based on their direct cases (Hathhorn Dir., Staff Ex. 1.0 at 44:1041-1047 and Att. A) and their rebuttal cases (Hathhorn Reb., Staff Ex. 15.0 at 35:783-785 and Att. H). The Utilities will provide the Commission with final rate case margins, based on the approved distribution charges, with their compliance filings. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 5:93-94.

#### b. Change in Annual Report (Uncontested)

Staff witness Ms. Hathhorn discussed a requirement from the last rate case Order that the Staff provide the Commissioners an annual report on the Utilities' rates of return and Rider VBA's effect on the return. *Peoples 2007* at 152. She recommended that the Utilities, rather than Staff, prepare this report. Hathhorn Dir., Staff Ex. 1.0 at 45:1059-1065. The Utilities accepted this proposal. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 53:1182 - 54:1186.

### E. Bill Impacts

The Utilities prepared detailed bill impact analyses for all service classifications affected by their rate proposals, at various usage levels under present and proposed rates. Grace Dir., NS Ex. VG-1.0 Rev. at 23:498-502 and NS Ex. VG-1.8; Grace Dir., PGL Ex. VG-1.0 Rev. at 25:550-554 and PGL Ex. VG-1.8. The Utilities provided additional analyses for the impact on S.C. No. 1 customers. Grace Dir., NS Ex. VG-1.0 Rev. at 17:355-360 and NS Ex. VG-1.6; Grace Dir., PGL Ex. VG-1.0 Rev. at 18:390-395 and PGL Ex. VG-1.6. The Utilities' proposed rate designs and resulting bill impacts are consistent with the objectives of continuity and

gradualism. Grace Dir., NS Ex. VG-1.0 Rev. at 1:19 - 2:23; Grace Dir., PGL Ex. VG-1.0 Rev. at 1:19 - 2:23.

## XIII. TRANSPORTATION ISSUES

### A. Overview

The Utilities proposed no operational changes to their transportation programs. Staff and intervenors proposed changes, all but one uncontested, concerning the large volume programs. For the contested issue, the Utilities showed that the proposal should be rejected. *See* Section XIII(C), *infra*. An intervenor group proposed changes concerning the small volume program ("Choices For You[sm]" or "CFY"), and the Utilities showed that the intervenor did not meet its burden of supporting changes to the CFY program. *See* Section XIII(D), *infra*. The proponents of these changes bear the burden of proof on these issues. *Central Illinois Public Service Company v. Illinois Commerce Commission*, 5 Ill. 2d. 195, 211 (1955).

The large volume program refers to customers taking service under Rider FST (Full Standby Transportation Service) or SST (Selected Standby Transportation Service). Many of these customers take service from alternative suppliers who "pool" customers under Rider P (Pooling Service). McKendry Reb., NS-PGL Ex. JM-1.0 at 6:110-112.

For the large volume programs, the Utilities implemented, on August 1, 2008, new operational provisions following their last rate cases. The Utilities believed it would be more beneficial to gain experience under the revised programs than to propose modifications in these cases. The Utilities proposed only updating the charges based on new cost studies; eliminating transitional riders that were in place as a bridge from the former programs to the revised programs that the Utilities implemented on August 1, 2008; making editorial changes; updating the number of "base rate" Allowable Bank days; and, for Peoples Gas, eliminating a rider under

which no customers take service. Grace Dir., NS Ex. VG-1.0 Rev. at 29:626 - 30:651; Grace Dir., PGL Ex. VG-1.0 Rev. at 32:704 - 33:739.

The CFY or small volume program refers to the customer choice program under which small residential (S.C. No. 1) and business (S.C. No. 2) customers select a third party gas supplier. Rider CFY (Choices For You[sm] Transportation Service) describes the terms and conditions of service for these customers. Rider AGG (Aggregation Service) describes the terms and conditions under which suppliers may aggregate CFY customers. Rider SBO (Supplier Billing Option Service) describes the terms and conditions under which a supplier may issue a single bill that includes utility charges. McKendry Reb., NS-PGL Ex. JM-1.0 at 14:304-310.

As with the large volume programs, the Utilities implemented changes following their last rate cases and proposed no substantive changes in these cases. *Id*. at 15:314-321. The Utilities proposed updating charges based on new cost studies. Grace Dir., NS Ex. VG-1.0 Rev. at 26:557-563 and NS Ex. VG-1.11; Grace Dir., PGL Ex. VG-1.0 Rev. at 28:610-616 and PGL Ex. VG-1.11; NS-PGL Ex. VG-2.0 at 64:1423 - 65:1426.

## B. Uncontested Issues

### 1. Elimination of Transportation Transition Riders

The Utilities implemented extensive changes to their transportation programs in their last rate cases. They provided a transition period before the changes took effect. Consequently, there were transition riders in effect to allow the Utilities to continue providing service until the new tariffs took effect. Those transition riders were called Riders FST-T, SST-T, LST-T, TB-T (Peoples Gas only) and P-T. As of August 1, 2008, no customer or supplier receives service under the transition riders, and the Utilities proposed to eliminate them. Grace Dir., NS

Ex. VG-1.0 Rev. at 29:626-633; Grace Dir., PGL Ex. VG-1.0 Rev. at 32:704-711. Neither Staff (Sackett Dir., Staff Ex. 12.0R at 4:83 - 5:97) nor any party opposed these proposals.

### 2. Riders FST, SST, and P Charges

The Utilities prepared cost studies to support the administrative charges under their transportation programs. NS Ex. VG-1.10; PGL Ex. VG-1.10. Based on its study, North Shore proposed to reduce its Riders FST and SST Administrative Charge from $8.94 to $7.32 per account and its Rider P Pooling Charge from $4.95 to $3.44 per account. Grace Dir., NS Ex. VG-1.0 Rev. at 26:553-557. Based on its study, Peoples Gas proposed to reduce its Riders FST and SST Administrative Charge from $11.24 to $9.87 per account and its Rider P Pooling Charge from $8.36 to $6.97 per account. Grace Dir., PGL Ex. VG-1.0 Rev. at 28:606-610. Neither Staff (Sackett Dir., Staff Ex. 12.0R at 14:290-299) nor any party opposed the proposals.

### 3. Intra-Day Nomination Rights

CNE-Gas witness Ms. Rozumialski proposed that the Commission require the Utilities to implement intra-day nomination rights for transportation customers. At a minimum, she recommended that the Commission require one other nomination cycle. Rozumialski Dir., CNE-Gas Ex. 1.0 at 8:148-152. A nomination is how a supplier notifies the Utilities of the quantity of gas that it plans to deliver to the Utilities. *Id*. at 5:87-90. The Utilities' current nomination deadline is 11:30 a.m. the day prior to the gas day (the "timely" cycle). Customers may also reallocate the nominated quantities at later times. McKendry Reb., NS-PGL Ex. JM-1.0 at 6:128 - 8:166. Ms. Rozumialski explained that interstate pipelines, but not local distribution companies like the Utilities, must offer four nomination cycles, namely: (1) timely (11:30 a.m. to take effect at the beginning of the next gas day, which is 9:00 a.m.); (2) evening (6:00 p.m. to take effect at the beginning of the next gas day); (3) intra-day 1 (10:00 a.m. to take

effect at 5:00 p.m. of that gas day); and (4) intra-day 2 (5:00 p.m. to take effect at 9:00 p.m. of that gas day). Rozumialski Dir., CNE-Gas Ex. 1.0 at 7:table-139.

The Utilities, citing operational and administrative concerns, did not agree to offer all four nomination cycles, as recommended by Ms. Rozumialiski, but they offered an alternative. McKendry Reb., NS-PGL Ex. JM-1.0 at 6:123 - 12:262; Dobson Reb., NS-PGL Ex. RD-1.0 Rev. at 20:433 - 25:557. For a four-year trial period, the Utilities proposed to add an "Evening Nomination Cycle." The customer or its supplier must make the nomination to the Utilities no later than 3:00 p.m. on the business day prior to the gas day on which it is to be effective. Unlike timely nominations, which are available every day, the new right would only apply to nominations on business days. The Utilities, by 2:00 p.m., would post on their PEGASys™ system the aggregate volume the Evening Cycle Nomination may not exceed. Except for Critical Days, the minimum quantity available (increases and decreases) would be 100,000 therms for Peoples Gas and 20,000 therms for North Shore. On Critical Supply Surplus Days, the Utilities would allow no increases. On Critical Supply Shortage Days, the Utilities would allow no decreases. The Utilities may also post separate quantities that apply to the allowable increases and decreases, *i.e*., increases of no more than X and decreases of no more than Y. The Utilities would reduce, *pro rata*, transportation customer Evening Cycle Nominations in excess of the posted available quantities. Dobson Reb., NS-PGL Ex. RD-1.0 Rev. at 24:521-535.

CNE-Gas stated that it was willing to accept the Utilities' proposal. CNE-Gas further stated it supported the proposal with the understanding that the Utilities would not change their current practices that allow nomination changes when an upstream supplier cuts a transportation customers' gas. Rozumialski Reb., CNE-Gas Ex. 2.0 at 4:77 - 5:87. The Utilities' witness Mr. McKendry agreed that the current practice will continue but stated that this is not a late

nomination but only a cut to the timely nomination. McKendry Sur., NS-PGL Ex. JM-2.0 at 3:65 - 4:71. The Utilities did not initially accept CNE-Gas' request to include the current practice in the tariff (*Id*. at 4:67-71), but in this Initial Brief, they agree to include tariff language describing this practice of revising timely nominations to address changes resulting from the confirmation process. Staff witness Mr. Sackett recommended that the Commission approve the Utilities' proposed intra-day nomination cycle. Sackett Reb., Staff Ex. 26.0 at 46:950-952.

#### 4. <u>Storage Credit</u>

Staff witness Mr. Sackett questioned why CFY suppliers, but not large volume transportation customers, receive a credit based on the Utilities' savings from reduced storage inventory requirements arising from transportation customers filing their Allowable Bank inventory. Sackett Dir., Staff Ex. 12.0R at 21:476-487. CFY suppliers receive such a credit, which was in the form of an offset to the Aggregation Charge. Grace Dir., NS Ex. VG-1.0 Rev. at 26:557-560; NS Ex. VG-1.11; Grace Dir., PGL Ex. VG-1.0 Rev. at 28:610-613; PGL Ex. VG-1.11. In response to Mr. Sackett (Staff Ex. 12.0R at 17:363), the Utilities propose to apply the storage credit as a stand alone credit per therm of MDQ. This would necessitate a new "Storage Credit" rate in Rider CFY. Rider AGG would only need to be revised to reflect the Aggregation Charge that will be approved in this consolidated proceeding. NS-PGL Ex. VG-2.0 at 64:1423 - 65:1426.

The Utilities agreed that such a credit for Riders FST and SST customers would be appropriate. The credit for S.C. No. 2 customers would differ from the large volume demand service classifications, S.C. No. 3 (North Shore) and S.C. No. 4 (Peoples Gas), because storage costs for S.C. No. 2 are fully bundled in base rates and this is not the case for the large volume demand rates. For Rider FST, the credit would be per therm of Maximum Daily Quantity

("MDQ"). For Rider SST S.C. No. 2 customers, the base rate credit amount would be per therm of MDQ and the gas charge credit amount would be per therm of Selected Standby Quantity ("SSQ"). For the Rider SST large volume demand service classifications, the credit would be per therm of SSQ. Grace Reb., NS-PGL Exs. VG-2.0 Rev at 55:1227 - 57:1252; VG-2.5N; VG-2.5P. Mr. Sackett accepted the proposal, with a condition concerning his unbundled Allowable Bank proposal that is moot in this proceeding. Sackett Reb., Staff Ex. 26.0 at 6:130-136.

**5. <u>Diversity Factors</u>**

Staff witness Mr. Sackett recommended that the Utilities update their Riders FST and SST diversity factors based on the most recent four years' data. Sackett Dir., Staff Ex. 12.0R at 25:565-566. The "diversity factor" is the result of dividing transportation customers' demand on the Utilities' peak day (coincident peak day) by the sum of transportation customers' peak day demand on any day (non-coincident peak day). *Id*. at 23:520-523. The factors affect the calculation of the transportation customers' Allowable Bank capacity and the Standby Demand Charge. NS Ex. VG-1.1 at 37, 39, 46, 50; PGL Ex. VG-1.1 at 42, 44, 51, 55. Peoples Gas agreed to reduce its diversity factor from 0.87 to 0.86, and North Shore agreed to reduce its diversity factor from 0.75 to 0.73. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 55:1215-1216.

**6. <u>Standby Commodity Charge</u>**

Staff witness Mr. Sackett proposed that the Standby Commodity Charge ("SCC") be set at a Chicago citygate price to prevent arbitrage. He stated that the current SCC calculation allows transportation customers to "arbitrage the difference" between the SCC and the Chicago citygate price. Transportation customers may purchase the Utilities' gas when the SCC is less than the Chicago citygate price and *vice versa*. Sackett Dir., Staff Ex. 12.0R at 42:933-946. The

SCC is based on, but not identical to, the Gas Charge that sales customers pay for gas. Transportation customers pay this price when they use their standby service rights to purchase gas from the Utilities. NS Ex. VG-1.1 at 39, 50; PGL Ex. VG-1.1 at 44, 55.

The Utilities agreed with Mr. Sackett's proposal. They proposed to use Chicago citygate price data published in Platts Gas Daily. Rider FST customers' usage is not daily metered, so the calculation would use an average price for the month, namely the existing definition of Average Monthly Index Price. Rider SST customers' usage is daily metered, so the calculation would use a daily price applicable to the flow date on which the imbalance occurred. An appropriate definition (Daily Index, Midpoint) is in Rider AGG. The Utilities proposed to revise Riders FST and SST to define the SCC price consistent with the existing definitions. Dobson Reb., NS-PGL Ex. RD-1.0 Rev. at 19:401-409; 19:417 - 20:425.[88] Mr. Sackett accepted the Utilities' proposal. Sackett Reb., Staff Ex. 26.0 at 45:933 - 46:934.

### 7. Maximum Daily Quantity (MDQ) Calculation

RGS witness Mr. Crist disputed the Utilities' calculation of the MDQ for CFY customers. Crist Dir., RGS Ex. 1.0 at 31:701-716. The Utilities currently round the calculation to the nearest dekatherm. They agreed to round to the nearest therm. McKendry Reb., NS-PGL Ex. JM-1.0 at 23:501-503. Mr. Crist agreed with this proposal. Crist Reb., RGS Ex. 2.0 Rev. at 22:493-496. The changed method also applies to the large volume transportation program, which has the same MDQ calculation. NS Ex. VG-1.1 at 38, 48; PGL Ex. VG-1.1 at 43, 53.

### 8. Rider SST Unbundled Allowable Bank

Staff witness Mr. Sackett proposed that the Utilities unbundle their Rider SST Allowable Bank from the standby service. Sackett Dir., Staff Ex. 12.0R at 25:570 - 42:931; Sackett Reb.,

[88] Rider P also includes the Standby Commodity Charge. NS Ex. VG-1.1 at 60; PGL Ex. VG-1.1 at 70.

Staff Ex. 26.0 at 7:138 - 43:855. The Utilities did not accept the proposal and raised several operational, administrative and rate concerns. Dobson Reb., NS-PGL Ex. RD-1.0 Rev. at 2:44 - 17:378; Dobson Sur., NS-PGL Ex. RD-2.0 at 2:37 - 13:276; Grace Reb. NS-PGL Ex. VG-2.0 Rev. at 57:1253 - 58:1273; Grace Sur., NS-PGL Ex. VG-3.0 at 30:659 - 36:784. In a data response, the Utilities agreed to work collaboratively with Staff, prior to filing their next rate cases, to develop proposals for unbundling standby and storage services that are provided to S.C. Nos. 2, 3 (North Shore), and 4 (Peoples Gas) customers under Riders FST and SST. The Utilities would file proposed tariff changes to implement any resulting mutually acceptable proposals, and, if and to the extent such proposals are not developed, to address such unbundling in their next rate case filings. ICC Staff Cross Exs. Grace 5 and 6.

#### 9. Elimination of Rider TB – Transportation Balancing Service

Peoples Gas proposed to eliminate Rider TB, Transportation Balancing Service. Few customers have taken this service and, currently, no customers are taking it. Grace Dir., PGL Ex. VG-1.0 Rev. at 32:713-716. Neither Staff (Sackett Dir., Staff Ex. 12.0R at 5:105-106) nor any party opposed the proposal.

### C. Large Volume Transportation Program

#### 1. Super Pooling on Critical Days

CNE-Gas witness Ms. Rozumialski recommended that the Commission require the Utilities to implement super pooling for measuring critical and supply surplus day thresholds. Rozumialski Dir., CNE-Gas Ex. 1.0 at 22:468-470. The Commission rejected such "super pooling" as proposed in the Utilities' 2007 rate cases, except for a specific inventory requirement that is determined on one day each year. *Peoples 2007* at 282-283.

Ms. Rozumialski described super pooling as pooling customer groups or pools under common management. Rozumialski Dir., CNE-Gas Ex. 1.0 at 21:447-451. The Utilities do not agree to implement super pooling for critical days[89]. The administrative burden and attendant concerns that the Utilities expressed in the last rate cases have not changed or been alleviated. McKendry Reb., NS-PGL Ex. JM-1.0 at 13:268-272. The Commission rejected the proposal in the Utilities' last rate case and, responding to CNE-Gas (referred to as "CNEG"), contrasted the burden of super pooling for the inventory requirement with that applicable to critical days:

> By its terms, annual cycling compliance will be quite regular and, per our ruling here, will occur only once each year. Accordingly, for purposes of calculating annual cycling compliance, the Utilities can predictably employ an "ad hoc process that will run tangentially to their existing processing and, therefore will not require [structural modifications to billing systems]." PGL Ex. TZ-3.0 at 16. In contrast, critical and supply surplus days are temporally and quantitatively erratic. To apply super-pooling to such unpredictable events, when the appropriate treatment of stand-alone accounts will have to be determined each time, would present the billing system complexity the Utilities reasonably want to avoid [footnote: On exceptions, CNEG argues that the Utilities could simply use the same process on critical and supply surplus days that they employ for injection season compliance. CNEG BOE at 7. That is correct, but misses the point. Since stand-alone accounts cannot be included whenever they use another supply source, the Utilities will have to determine their status for each critical or surplus day.]. *Id.* at 14. Moreover, it would likely and excessively entangle the utilities in the relationship between suppliers and individual customers with respect to allocation of daily gas deliveries. *Id*. at 17.

*Peoples 2007* at 282-283. Although CNE-Gas claims that its proposal in the instant case places the burden of the super pool determination on the supplier (Rozumialski Reb., CNE-Gas Ex. 2.0 at 6:120-124), this is incorrect. The Utilities would need to review the accuracy of the supplier's request and, if it conforms to the applicable super pooling requirements, balance the contracts

[89] The Utilities note that CNE-Gas' terminology ("critical and supply surplus days") is unclear. Rider SST states that a Critical Day is either a "Supply Surplus Day" or a "Supply Shortage Day." NS Ex. VG-1.1 at 47; PGL Ex. VG-1.1 at 52. It is unclear if CNE-Gas' proposal is directed to all Critical Days or only Supply Surplus Days.

and bill based on the outcome of that day's balancing. The Utilities are ultimately responsible for implementing the process. McKendry Sur., NS-PGL Ex. JM-2.0 at 4:85 - 5:92.

The Commission's conclusions in the last rate cases apply to the proposal in the instant cases and, for those reasons, CNE-Gas' super pooling proposal should be rejected.

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

#### 1. Allocation of and Access to Company-owned Assets

RGS witness Mr. Crist claimed that the Utilities recover the same amount of storage costs from sales and CFY customers, but CFY customers do not receive the same rights to that storage. Crist Dir., RGS Ex. 1.0 at 10:219-222. He argued that the Utilities should allocate storage capacity in a similar manner to Nicor. *Id*. at 17:388-389. Alternatively, he argued that the Commission should order the Utilities to reduce the Aggregation Balancing Gas Charge ("ABGC"). *Id*. at 19:418-421. RGS' alternative proposal is addressed in Section XIII(D)(2), *infra*.

RGS is incorrect. CFY customers and suppliers receive benefits from the Utilities' storage comparable to sales customers.

First, the Commission addressed this same recommendation in the Utilities' last rate cases and rejected RGS' arguments. *Peoples 2007* at 288-293. RGS has raised nothing new. The Utilities proposed no changes to the CFY customers' and suppliers' storage rights and obligations. In the short period since the last rate case, sales customers have not acquired any additional or superior rights. RGS has presented no evidence that warrants the Commission reaching a different conclusion.

Second, CFY suppliers have significant flexibility to use the benefits that storage can offer, and the Utilities' decisions for their sales customers must work around the constraints

caused by the CFY suppliers. For example, CFY suppliers know by 8:45 a.m. every business day, prior to making purchase decisions, the quantity of gas they will need to deliver to the Utilities. This quantity includes an allocation of the storage injection, withdrawal and capacity rights that mirror those the Utilities use for sales customers. With this knowledge, CFY suppliers can then vary their deliveries within a 10% band, even on Critical Days, around the known delivery level for any reason, including to take advantage of market price variations. In contrast, the Utilities make daily purchase decisions for sales customers without knowing how CFY deliveries will vary from the projected quantity and must remain prepared to meet CFY variations that are not known until after the fact. Dobson Reb., NS-PGL Ex. RD-1.0 Rev. at 27:591 - 28:603. As another example, the Utilities' storage injection and withdrawal rights are constrained by limitations in the pipeline providers' tariffs or other restrictions that the pipeline imposes (such as in response to *force majeure*). These limitations include injection and withdrawal ratchets and upstream source and transportation requirements. The tariffs limit where the Utilities can buy gas and how the Utilities can transport gas. Peoples Gas' storage field (Manlove Field) also has operating limitations. Conversely, the CFY suppliers deliver gas based on projected customer requirements, without regard to storage and pipeline issues, and within a 10% tolerance band. *Id*. at 28:604-614.

Third, the Utilities use system assets to support several benefits for CFY suppliers that would not exist if the CFY suppliers were dealing with unbundled pipeline services, as the Utilities must do. These benefits include the facts that: CFY suppliers may transport gas to the citygate using any pipeline that interconnects with the Utilities; CFY suppliers have access to storage without having to specifically nominate injections or withdrawals; and CFY suppliers receive a daily balancing service. NS-PGL Ex. RD-2.0 at 13:281 - 14:296.

Finally, RGS has not shown how Nicor's allocation of storage rights and management of its version of the CFY program (Customer Select) are relevant to what the Utilities can or should adopt for their programs. Nicor's system is not the same as the Utilities' systems. The record includes no evidence as to how Nicor's supply personnel manage and support service for Customer Select. The record includes no evidence as to how Nicor coordinates service under Customer Select with its other transportation programs. Dobson Reb., NS-PGL Ex. RD-1.0 Rev. at 26:572 - 27:584. There is no record support for taking a piece of another utility's transportation program and imposing it on the Utilities.

RGS' contention that the CFY customers and suppliers are receiving inferior service relative to sales customers is incorrect. RGS' proposal that the Utilities' program, or at least the piece of it associated with how the Utilities allocate storage capacity to CFY customers and suppliers, should be "similar to the program, in place at Nicor Gas" (Crist Dir., RGS Ex. 1.0 at 17:388-389) is undeveloped and lacks record support. The Commission should reject RGS' proposal that the Utilities change how storage is handled under Rider AGG.

### 2. Payment for Company-owned Assets / Aggregation Balancing Gas Charge

RGS proposed, as an alternative to its request for greater access to storage assets, that the Commission require the Utilities to reduce the ABGC. Crist Dir., RGS Ex. 1.0 at 19:418-421. Reducing the ABGC would only be appropriate if the CFY customers were not receiving the benefits for which they were paying through the ABGC. As demonstrated in Section XIII(D)(1), *supra*, CFY customers are receiving these benefits. Moreover, RGS witness Mr. Crist's contention that the Utilities "recover the same amount of storage costs from both sales and Choices For You customers" is incorrect. Crist Dir., RGS Ex. 1.0 at 10:219-220.

Mr. Crist states that off-system storage costs are recovered from sales customers through the Non-Commodity Gas Charge ("NCGC") and from CFY customers through the ABGC. *Id*. at 10:212-214. This is correct, but disingenuous in the context of arguing that the Utilities recover the "same amount" of storage costs from sales and CFY customers. *Id*. at 10:219-220. As Mr. Crist acknowledged, the NCGC does not recover exactly the same costs as the ABGC. Crist, Tr. at 561:5-8. In fact, the ABGC is less than the NCGC. Specifically, the ABGC is defined as "a non-commodity related, per therm, gas cost recovery mechanism applied to all therms delivered or estimated to be delivered by the Company to customers served under Rider CFY. This charge is equivalent to the NCGC less any costs not associated with balancing or storage. Revenues arising through the application of this charge will be credited to the Factor NCGC." (emphasis added) NS Ex. VG-1.1 at 17; PGL Ex. VG-1.1 at 20. This rate design recognizes that the Utilities provide storage and balancing services to the CFY customers and suppliers. Consequently, only costs associated with those services are properly recovered from the ABGC, and those are the only costs recovered from the CFY customers. Further reducing the ABGC would result in sales customers subsidizing the CFY customers by paying costs associated with the balancing and storage services that CFY customers and their suppliers receive. Those services are substantial, as described in Section XIII(D)(1), *supra*. There is no record support for reducing the ABGC.

### 3. Allocation of Administrative Costs and Related Charges

RGS contends that the Utilities should recover through base rates applicable to all customers the costs that are the basis for the CFY administrative charges and the LDC Billing Option. Crist Dir., RGS Ex. 1.0 at 19:437 - 20:442. The proposal is inconsistent with cost causation principles and would result in sales customers subsidizing customers who elect to take

transportation service. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 64:1407-1417. The CFY Administrative Charge recovers the Utilities' cost of administering their CFY transportation programs. The Utilities presented a specific cost study, identifying the activities and functions and the related costs, to support the proposed CFY Administrative Charges. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 63:1391-1394; Grace Dir., NS Ex. VG-1.0 Rev. at 26:560-562; VG-1.10; Grace Dir., PGL Ex. VG-1.0 Rev. at 28:613-615; PGL Ex. VG-1.10. The LDC Billing Option charges recover the Utilities' cost of rendering a bill with supplier specified charges, on behalf of the supplier, and remitting customer payments to the supplier. Grace Reb., NS-PGL Ex. VG-2.0 Rev. at 63:1400 - 64:1403. The costs in question are properly assessed to CFY suppliers for services those suppliers receive. Assessing these costs to all customers (sales and transportation) would be improper and should be rejected.

#### 4. Rider SBO Issues

RGS witness Mr. Crist argues that Rider SBO should be revised in two ways. First, he states that customers in payment arrears to the Utilities should not be removed from receiving a Rider SBO bill. Crist Dir., RGS Ex. 1.0 at 25:568-569. Second, he states that there should be a mechanism allowing a customer's credit on its utility bill to be transferred to the supplier. Crist Dir., RGS Ex. 1.0 at 26:583-587.

Rider SBO describes the terms and conditions under which a supplier may choose to issue a single bill that includes utility charges. McKendry Reb., NS-PGL Ex. JM-1.0 at 14:309-310. Turning to RGS' first request concerning customer arrearages, customers leaving budget billing when they switch to CFY seems to be a significant part of RGS' concern. Crist Dir., RGS Ex. 1.0 at 24:549 - 25:562. This is not a basis for changing Rider SBO. First, a customer who is participating in the Utilities' budget billing plan may receive a Rider SBO bill.

McKendry Sur., NS-PGL Ex. JM-2.0 at 5:106-107. Second, it is common for an alternative supplier to request that the Utilities remove a customer from the budget payment plan. McKendry Reb., NS-PGL Ex. JM-1.0 at 15:327-329. The alternative supplier is, therefore, in control of the situation and can remedy the issue, for example, by ensuring that the arrearage is paid. McKendry Sur., NS-PGL Ex. JM-2.0 at 6:114-116. Third, the origin of the Rider SBO provision at issue was that, in Docket Nos. 01-0469 and 01-0470, when the Utilities introduced Rider SBO, suppliers raised issues over collecting utility arrearages that, in their opinion, would create customer confusion and have a negative impact on competition. The suppliers also argued that the Utilities needed to address receivables risk under Rider SBO. The Utilities did so by including terms and conditions in Rider SBO that insulated suppliers from receivables risk. The Commission agreed with the Utilities' proposal. *In re North Shore Gas Company*, ICC Docket No. 01-0469, at 26 (Order, Mar. 5, 2002); *In re The Peoples Gas Light and Coke Company*, ICC Docket No. 01-0470, at 30 (Order, Mar. 5, 2002).

Turning to RGS' second request concerning credit balances, Mr. Crist's request is predicated on the customer consenting to the credit transfer. Crist Dir., RGS Ex. 1.0 at 26:586-587. The Utilities have no ready way to verify if a supplier's agreement with the customer includes provisions permitting such a transfer. In general, the terms and conditions in suppliers' agreements may differ from supplier to supplier and the same supplier may have different contract forms. McKendry Reb., NS-PGL Ex. JM-1.0 at 17:367-370. When asked to provide form agreements, RGS merely provided a single example of language that it stated a supplier includes in its agreements. RGS Ex. 2.4; Crist, Tr. at 575:9 - 576:1. There is no evidence that all suppliers have such language in their agreements. There is no evidence that the supplier from whose agreement form(s) the quoted language was lifted includes that language in

all its agreements. Crist, Tr. at 576:2-5. The Utilities do not review each customer's agreement to determine what rights a supplier may have to manage a customer's account. Furthermore, the customer may have legitimate reasons to have the Utilities refund that credit and not transfer it to the supplier. McKendry Reb., NS-PGL Ex. JM-1.0 at 17:371-374.

For both Rider SBO issues, RGS has not met its burden of showing that a change to the Rider SBO is required. Moreover, for both issues, the supplier is able to address the situation directly with the customer with whom it has a contractual relationship, whether by ensuring that arrearages are paid before taking actions that could jeopardize the customer's receipt of Rider SBO bills or by arranging for the customer to transfer a credit to it. The Commission should reject RGS' proposals.

**5. <u>New Customer Issues</u>**

Mr. Crist argues that the Utilities' processes applicable to new customers should be revised. He states that a new customer should be able to take CFY service immediately and not first apply for and take service as a sales customer. Crist Dir., RGS Ex. 1.0 at 29:653-654. The Utilities' process, applicable to all service applicants, is that an applicant starts receiving service only when the gas is turned on or, if the service is left on by the previous customer, when the Utilities obtain a meter reading. This requires scheduling a field service order. The account is "pending" until the gas is turned on. The account becomes "active" once the service order is complete. McKendry Reb., NS-PGL Ex. JM-1.0 at 20:436-443. The Utilities do not accept CFY enrollment requests that suppliers submit when customers' accounts are "pending" for practical reasons. Many things can change between the service request and when service orders are scheduled. For example, customers may cancel the service request before the scheduled turn-on date or re-schedule the turn-on date. Also, the Utilities are concerned that activating customers'

accounts immediately in supplier's pools is inconsistent with Senate Bill 171's requirement that allows customers a minimum of 10 business days from the Utilities' notice to rescind contracts with their suppliers. *Id*. at 21:445-460.

The Utilities' practice concerning new customers is reasonable, and the Commission should not order a change.

### 6. <u>Customer Switching Issues</u>

Mr. Crist argues that the Utilities' customer switching practice delays the customer switch for an extra nine days beyond what is required by law. He recommends that the Commission require the Utilities to reduce the period from 19 to the 10 days that he states is required by Senate Bill 171. Crist Dir., RGS Ex. 1.0 at 644-645. Mr. Crist's recommendation is inconsistent with Senate Bill 171 and must be rejected. First, the statutory contract rescission period is 10 business days and not calendar days, as he acknowledged. 220 ILCS 5/19-115(g)(6); Crist, Tr. at 573:8-14; McKendry Reb., NS-PGL Ex. JM-1.0 at 19:420-422. Second, Mr. Crist appears not to recognize that the event that triggers the start of the 10-business day period is the Utilities' notice to the customer. 220 ILCS 5/19-115(g)(6); Crist, Tr. at 573:15-18; McKendry Reb., NS-PGL Ex. JM-1.0 at 19:420-422. Third, the Utilities have two business days from receiving the supplier request to send the notice to the customer. 220 ILCS 5/19-115(g)(6); McKendry Reb., NS-PGL Ex. JM-1.0 at 418-419. Fourth, this 12-business day period necessarily includes two weekends, *i.e.*, four more calendar days. McKendry Sur., NS-PGL Ex. JM-2.0 at 7:147-149. Finally, many months include a State holiday. *Id*. at 7:146.

The Utilities' 19-day period is a reasonable and narrow window that ensures compliance with Senate Bill 171, the relevant portion of which is codified at 220 ILCS 5/19-115(g)(6). In contrast, Mr. Crist's comparison of 19 to 10 calendar days to claim that the Utilities improperly

extend the period by nine days is clearly incorrect, and his recommendation to reduce the window to 10 days would be contrary to the law.

### 7. Administrative Improvements to Supplier Billing System and PEGASys System Improvements

Mr. Crist contends that the Utilities do not state inventory or storage volume on the monthly bill, and the Utilities should provide this information on the bill. Crist Dir., RGS Ex. 1.0 at 30:689-690. The Utilities provide that information through reports available to suppliers via PEGASys™ at any time. McKendry Reb., NS-PGL Ex. JM-1.0 at 21:464-466. The requested information is readily available, and there is no basis for the Commission to order the Utilities to provide the information in a different format.

Mr. Crist also stated that the Utilities should make "improvements in their supplier billing and Pegasus (*sic*) system." Crist Dir., RGS Ex. 1.0 at 9:183-184. There is no explanation as to what PEGASys™ system improvements RGS is seeking. Consequently, there is nothing on which the Commission may act.

## XIV. CONCLUSION

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

Dated: September 29, 2009

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**CERTIFICATE OF SERVICE**

I, John P. Ratnaswamy, do hereby certify that a copy of the foregoing INITIAL POST-HEARING BRIEF OF NORTH SHORE GAS COMPANY AND THE PEOPLES GAS LIGHT AND COKE COMPANY was served upon all parties on the attached Service List by electronic mail on September 29, 2009, before 5:00 p.m.

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