STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	**:**	
	:	**11-0280**
Proposed general increase in natural gas rates. (Tariffs filed on February 15, 2011)	**: :**	
	:	
The Peoples Gas Light and Coke Company	**:**	**11-0281**
	:	
Proposed general increase in natural gas rates. (Tariffs filed on February 15, 2011)	**: :**	**Cons.**

PROPOSED ORDER

[Draft Proposed Order Submitted by North Shore Gas Company and The Peoples Gas Light and Coke Company]

__________ __, 201_

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ORDER

By the Commission:

PROCEDURAL HISTORY

On February 15, 2011, North Shore Gas Company ("North Shore" or "NS") filed with the Illinois Commerce Commission ("Commission"), pursuant to Section 9-201 of the Public Utilities Act (the "Act") (220 ILCS 5/9-201), the following revised tariff sheets: ILL. C.C. No. 17, Title Sheet and ILL. C. C. No. 17, Sheet Nos. 1-4, 6, 8-10, 17-28, 32-39, 44-48, 57-97, 100, 102-104, 107, 111, 112, 114, 123-125, 134-149, 157, 161, 170-186. This tariff filing embodied a proposed general increase in gas service rates, and revisions of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286 of Title 83 of the Illinois Administrative Code (the "Code"), 83 Ill. Admin. Code Parts 285 and 286.

On February 15, 2011, The Peoples Gas Light and Coke Company ("Peoples Gas" or "PGL") filed with the Commission, pursuant to Section 9-201 of the Act, the following revised tariff sheets: ILL. CC. No. 28, Title Sheet and ILL. C. C. No. 28, Sheet Nos. 1-5, 7-9, 16, 18-29, 32-39, 44-48, 58-85, 93-104, 106, 108-110, 113, 117, 118, 120, 130, 139-141, 150-163, 168, 172, 181-197. This tariff filing embodied a proposed general increase in gas service rates and revisions of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286 of the Code.

Notices of the proposed tariff changes reflected in these rate filings were posted in North Shore's and Peoples Gas' (the "Utilities" or "Companies") business offices and published in secular newspapers of general circulation in the Utilities' respective service areas, as evidenced by publishers' certificates, in accordance with the requirements of Section 9-201(a) of the Act and the provisions of 83 Ill. Admin. Code Part 255.

The Commission issued a Suspension Order for North Shore's tariff filing on March 23, 2011, which suspended the tariffs to and including July 14, 2011, and further initiated Docket 11-0280. On July 7, 2011, the Commission issued a Resuspension Order that suspended these tariffs to, and including, January 14, 2012.

The Commission issued a Suspension Order for Peoples Gas' tariff filing on March 23, 2011, which suspended the tariffs to and including July 14, 2011, and initiated Docket 11-0281. On July 7, 2011, the Commission issued a Resuspension Order that suspended these tariffs to, and including, January 14, 2012.

On April 5, 2011, North Shore and Peoples Gas (collectively, the "Utilities") each filed motions for protective orders in each Docket, pursuant to 83 Ill. Admin. Code §200.600. On the same date, the Utilities also filed motions to remove the confidential and proprietary designations from Mr. Schott's direct testimony relating to year-end return on common equity, the Utilities' most recent actuarial report, and Part 285.315(c) Attachment B.

On April 11, 2011, the Administrative Law Judges ("ALJs") held an initial status hearing and, on the oral motion of Commission Staff ("Staff"), consolidated these cases and also orally approved a case schedule and data request response time schedule.

On April 12, 2011, the Utilities filed a motion for entry of case management plan and schedule, pursuant to Section 10-101.1 of the Act and 83 Ill. Admin. Code §§ 200.190, 200.370, and 200.500.

On April 13, 2011, the ALJs issued a notice of schedule.

Rulings on motions are discussed further below.

Petitions to Intervene

Petitions to Intervene were filed or appearances were entered on behalf of the Attorney General of the State of Illinois (the "Attorney General" or "AG"); the Citizens Utility Board ("CUB"); the City of Chicago (the "City") (collectively, CUB and the City are "CUB/City") (collectively, the AG, CUB, and the City are "AG/CUB/City or also "GCI" for "Governmental and Consumer Intervenors"); Constellation NewEnergy-Gas Division, LLC ("CNE"); Ford Motor Company and Merchandise Mart proceeding as the Illinois Industrial Energy Consumers ("IIEC"); Integrys Energy Services-Natural Gas LLC ("IES"); Interstate Gas Supply of Illinois, Inc. ("IGS"); and Vanguard Energy Services, LLC. All petitions were granted by the ALJs.

The Evidentiary Hearing

The evidentiary hearing was held August 29, 2011 through September 2, 2011, and September 6, 2011, at the offices of the Commission in Chicago, Illinois. At the evidentiary hearings, the Utilities, Staff, and the Intervenors entered appearances and presented testimony. The following witnesses testified on behalf of the Utilities: James F. Schott, Vice President-External Affairs, Integrys Energy Group, Inc., North Shore and Peoples Gas (NS Ex. 1.0, PGL Ex. 1.0, NS-PGL 17.0, NS-PGL Ex 34.0); Lisa J. Gast, Manager, Financial Planning and Analysis, Integrys Business Support, LLC (NS Ex. 2.0, PGL Ex. 2.0, NS-PGL Ex. 18.0, NS-PGL Ex. 35.0); Paul R. Moul, Managing Consultant, P. Moul & Associates (NS Ex. 3.0 REV, PGL Ex. 3.0 REV, NS-PGL Ex 19.0 REV, NS-PGL Ex. 36.0); Steven M. Fetter President, Regulation UnFettered (NS-PGL Ex. 20.0, NS-PGL Ex. 37.0); Kevin R. Kuse, Senior Load Forecaster, Integrys Business Support, LLC (NS Ex. 4.0 REV, PGL Ex. 4.0 REV, NS-PGL Ex. 32.0, NS-PGL Ex. 48.0); Christine M. Gregor, Director, Operations Accounting, North Shore and Peoples Gas (NS Ex. 5.0, PGL Ex. 5.0, NS-PGL Ex. 21.0 Corr., NS-PGL Ex. 38.0); Sharon Moy, Rate Case Consultant, Regulatory Affairs, Integrys Business Support, LLC (NS Ex. 6.0, PGL Ex. 6.0, NS-PGL Ex. 22.0 2 Corr., NS-PGL Ex. 39.0 Corr.); John Hengtgen, Consultant, Stafflogix Corporation (NS Ex. 7.0, PGL Ex. 7.0, NS-PGL Ex. 23.0 Corr., NS-PGL Ex. 40.0 Corr.); Edward Doerk, Vice President, Gas Standardization, The Peoples Gas Light and Coke Company and North Shore Gas Company (NS Ex. 8.0, PGL Ex. 8.0 (except for the portion adopted by witness Phillip M. Hayes), NS-PGL Ex. 24.0 (same), NS-PGL Ex. 41.0); Noreen E. Cleary, Assistant Vice President, Total Compensation, Integrys Energy Group, Inc. (NS Ex. 9.0, PGL Ex. 9.0, NS-PGL Ex. 25.0, NS-PGL Ex. 43.0); John P. Stabile, Tax Director, Integrys Business Support, LLC NS Ex. 10.0, PGL Ex. 10.0, NS-PGL Ex. 26.0, NS-PGL Ex. 44.0); Christine Phillips, Manager, Benefits Accounting, Integrys Business Support, LLC (NS Ex. 11.0, PGL Ex. 11.0, NS-PGL Ex. 27.0); Valerie H. Grace, Manager, Gas Regulatory Services, Integrys Business Support. LLC (NS Ex. 12.0, PGL Ex. 12.0 REV, NS-PGL Ex. 28.0, NS-PGL Ex. 45.0), Joylyn C. Hoffman-Malueg, Rate Case Consultant, Regulatory Affairs, Integrys Business Support, LLC (NS Ex. 13.0, PGL Ex. 13.0, NS-PGL Ex. 29.0); Thomas Connery, Supervisor, Gas Supply Trading, Integrys Business Support, LLC (NS Ex. 14.0, PGL Ex. 14.0, NS-PGL Ex. 30.0, NS-PGL Ex. 46.0); John McKendry, Senior Leader, Gas Transportation Services, Integrys Business Support, LLC (NS Ex. 15.0, PGL Ex. 15.0, NS-PGL Ex. 31.0, NS-PGL Ex. 47.0); Thomas L. Puracchio, Manager, Gas Storage, Integrys Business Support, LLC (PGL Ex. 16.0, NS-PGL Ex. 33.0 REV), Phillip M. Hayes, Director, Project Management, Integrys Business Support, LLC (PGL Ex. 8.0 (portion), NS-PGL Ex. 24.0 (portion), NS-PGL Ex. 42.0).

The following witnesses testified on behalf of Staff: Daniel Kahle, Accountant, Accounting Department Financial Analysis Division, Illinois Commerce Commission (Ex. 1.0, Ex. 10.0); Mike Ostrander, Accountant, Accounting Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 2.0, Ex. 11.0 Corr., Ex. 20.0); Theresa Ebrey, Accountant, Accounting Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 3.0, Ex. 12.0 Corr.), Sheena Kight-Garlisch, Senior Financial Analyst, Finance Department, Illinois Commerce Commission (Ex. 4.0, Ex. 13.0 Corr.); Michael McNally, Senior Financial Analyst, Finance Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 5.0 Corr., Ex. 14.0 Corr.), David Brightwell, Economic Analyst, Policy Program, Energy Division, Illinois Commerce Commission (Ex. 6.0, Ex. 15.0); Cheri L. Harden, Rates Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 7.0, Ex. 16.0), Brett Seagle, Engineering Department, Energy Division, Illinois Commerce Commission (Ex. 8.0, Ex. 17.0), David Sackett, Economic Analyst, Policy Program, Energy Division, Illinois Commerce Commission (Ex. 9.0, Ex. 18.0); David Rearden, Policy Program, Energy Division, Illinois Commerce Commission (Ex. 19.0).

GCI's witnesses were: Lafeyette Morgan, Consultant, Exeter Associates, Inc. (GCI Ex. 1.0 Corr., GCI Ex. 6.0); David J. Effron, Consultant (GCI Ex. 2.0 Corr., GCI Ex. 7.0); Scott Rubin, Consultant (GCI Ex. 3.0, GCI Ex. 8.0); David E. Dismukes, Consulting Economist, Acadian Consulting Group (GCI Ex. 4.0, GCI Ex. 9.0); Christopher C. Thomas, Director of Policy, Citizens Utility Board (GCI Ex. 5.0, GCI Ex. 10.0).

Interstate Gas Supply of Illinois' witness was: Vincent A. Parisi, General Counsel, Interstate Gas Supply of Illinois, Inc. (IGS Ex. 1.0, IGS Ex. 2.0).

Illinois Industrial Energy Consumers and Constellation NewEnergy's witness was: Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc. (IIEC-CNE Ex. 1.0, IIEC-CNE Ex. 2.0).

Constellation NewEnergy-Gas Division's witness was: Jason R. Kawczynski, Associate of Volume Management, Constellation NewEnergy-Gas Division, LLC (CNE Ex. 1.0, CNE Ex. 2.0).

The above references to testimony are intended to include the attachments thereto, whether given separate exhibit numbers or not.

All parties were given the opportunity to cross-examine witnesses. On __________ __, 2011, the ALJs marked the record "Heard and Taken".

Rulings on Motions

A status hearing was held April 11, 2011, where the ALJs granted Staff's motion to consolidate these Dockets.

On April 11, 2011, the ALJs granted Utilities' motion to remove the confidential and confidential and proprietary designations from the direct testimony of Mr. Schott, the actuarial report submitted pursuant to Part 285.305(g), and Attachment B to Part 285.315(c).

On May 5, 2011, the ALJs issued an Order for Case Management Plan and Schedule in these dockets. On the same date, after considering all of the parties' arguments, the ALJs entered a Protective Order for these dockets.

On August 25, 2011, the ALJs denied the Utilities' motion to strike portions of Staff Exhibit 14.0 and Schedules 14.1 through 14.4.

On August 29, 2011, the ALJs granted Staff's motion for leave to file supplemental rebuttal testimony of Mr. Ostrander. On the same date, the ALJs denied the Utilities' renewed motion to strike portions of Staff Exhibit 14.0 and Schedules 14.1 through 14.4.

On __________ __, 2011, the ALJs __________ the Utilities' Verified Motion to Preserve the Confidential Designations of Certain Documents (Revised).

Post-Hearing Briefs

On September 22, 2011, the Utilities, Staff, the AG, City-CUB, IES, IGS, and IIEC-CNE each filed Initial Briefs ("Init. Br.").

On September 27, 2011, per direction of the ALJs, the Utilities submitted a draft Proposed Order and ___________ submitted draft position statements.

On October 6, 2011, the Utilities, __________, and _________ each filed Reply Briefs ("Rep. Br.").

On __________ __, 2011, the ALJs issued their Proposed Order.

On __________ __, 2011, Briefs on Exceptions ("BOE") were filed by __________.

On __________ __, 2011, Reply Briefs on Exceptions ("RBOE") were filed by __________.

This Order considers all of the positions and arguments set out in the exceptions briefs and reply briefs on exceptions listed above.

* * *

II. TEST YEAR (Uncontested)

The Utilities proposed forecasted calendar year 2012, the twelve months ending December 31, 2012, as their test year. NS Ex. 6.0 at 4-5; PGL Ex. 6.0 at 4-5. The 2012 test year data were based on the Utilities' forecasted 2012 revenues, expenses, and rate bases, subject to appropriate adjustments. NS Ex. 6.0 at 4-5; 6; NS Ex. 5.0 at 4-5; PGL Ex. 6.0 at 4; 6; PGL Ex. 5.0 at 4-5. The proposed test year is uncontested. The Commission approves the test year as reasonable.

III. REVENUE REQUIREMENT

Under long-established federal and Illinois constitutional law, and Illinois ratemaking law, a utility's rates must be set so as to allow it the opportunity to obtain full recovery of its prudent and reasonable costs of service, including its costs of capital.[1] The legal standards governing a utility's right to a fair and reasonable rate of return, in particular, are well established and familiar. 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. The Commission "fully embraces the principles set forth" in the *Bluefield* and *Hope* cases. *In re Consumers Ill. Water Co.,* ICC Docket No. 03-0403 (Order April 13, 2004), p. 41. Allowing a utility the opportunity to recover fully its costs of service, including its costs of capital, is in the long-term interests of customers, because this is necessary in order for the utility to be able to provide adequate, safe, and reliable service over time at the least long term cost. PGL Ex. 1.0 at 3; NS Ex. 1.0 at 3.

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 and its stockholders as well as customers. *E.g., Bus. and Prof. People for the Pub. Interest v. Illinois Commerce Comm'n*, 146 Ill. 2d 175, 208, 585 N.E.2d 1032, 1045 (1991) ("*BPI II*").

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[1] *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); *Commonwealth Edison Co. v. Illinois Commerce Comm'n,* 322 Ill. App. 3d 846, 849, 751 N.E.2d 196, 199 (2d Dist. 2001) ("*ComEd*") (citing *Citizens Utilities Co. v. Illinois Commerce Comm'n*, 124 Ill. 2d 195, 200, 529 N.E.2d 510, 512 (1988) ("*Citizens Utilities*"); *see also Citizens Utility Board v. Illinois Commerce Comm'n*, 166 Ill. 2d 111, 121, 651 N.E.2d 1089, 1095 (1995) ("*CUB*") (involving costs recovered under a rider).

The formula for determining a utility's costs of service -- its revenue requirement -- is well established and uncontested. 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 rate base ("RB"). *E.g., ComEd*, 322 Ill. App. 3d at 849, 751 N.E.2d at 199.

A. <u>North Shore</u>

North Shore

North Shore's existing rates fall short of allowing it to recover fully its costs of service. North Shore's comprehensive direct case supported in detail a base rate revenue requirement of $83,313,000, which meant that its cost recovery shortfall (its revenue deficiency) under existing rates in the 2012 test year would be $8,594,000. NS Ex. 6.0 at 6; NS Ex. 6.1 at Sched. C-1, line 5.

Consistent with the revenue requirement formula discussed above, North Shore'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. 6.1 at Sched. C-1, lines 5, 33, 34. The operating income requirement number is the product of multiplying the utility's rate base by its cost of capital. *E.g.,* NS Ex. 6.1 at Sched. A-2, lines 1-7, and Sched. C-1, line 33. The revenue requirement figure does not include the Cost of Gas recovered under Rider 2 or any costs recovered under Riders 11, EEP, UEA, VBA, or FCA. *E.g.,* NS Ex. 6.0 at 2.

The drivers of the cost under-recovery were discussed in detail in direct and rebuttal testimony. NS Ex. 1.0 at 9-11; NS-PGL Ex. 17.0 at 11-12; NS Ex. 5.0 at 11-13. 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.

Other Parties

[Insert]

North Shore Response

North Shore's detailed rebuttal testimony supported a revised base rate revenue requirement of $83,579,000, with a reduced cost recovery shortfall under current rates of $8,409,000. NS-PGL Ex. 22.1N 2 Corr. at Sched. C-1, line 5. The revisions reflected that North Shore, in its rebuttal, agreed with or accepted in order to narrow the issues, in whole or in part, a number of Staff's and GCI's proposed adjustments, and updated certain items, including, among others, a reduced proposed ROR reflecting a reduced proposed ROE. NS-PGL Ex. 22.0 2 Corr. at 2; NS-PGL Ex. 22.2N Corr. at Sched. C-2; NS-PGL Ex. 18.1N.

Finally, North Shore's detailed surrebuttal testimony supported a revised base rate revenue requirement of $83,384,000, with a further reduced cost recovery shortfall under current rates of $8,214,000(the figures including rider and other revenues other than PGA and coal tar revenues are $85,074,000 and $8,347,000, respectively). NS-PGL Ex. 39.0 Corr. at 3; NS-PGL Ex. 39.1N at Sched. C-1, line 5. The additional reductions reflected that North Shore, in its surrebuttal, again agreed with or accepted, in whole or in part, certain Staff-proposed adjustments and updated certain items, among them a reduced proposed ROR reflecting a reduced proposed ROE. NS-PGL Ex. 39.0 Corr. at 2, 4; NS-PGL Ex. 39.2N at Sched. C-2.

Commission Analysis and Conclusion

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

B. <u>Peoples Gas</u>

Peoples Gas

Peoples Gas' existing rates fall far short of allowing it to recover its costs of service. Peoples Gas' comprehensive direct case supported in detail a base rate revenue requirement of $613,779,000, which meant that its cost recovery shortfall under existing rates as of the 2012 test year would be $123,652,000. PGL Ex. 6.0 at 6; PGL Ex. 6.1 at Sched. C-1, line 5.

Consistent with the revenue requirement formula discussed above, Peoples Gas' base rate revenue requirement is the sum of (1) its base rate operating expenses plus (2) its operating income requirement. *E.g.,* PGL Ex. 6.1 at Sched. C-1, lines 5, 33, 34. The operating income requirement number is simply the product of multiplying the utility's rate base by its cost of capital. *E.g.,* PGL Ex. 6.1 at Sched. A-2, lines 1-7, and Sched. C-1, line 33. The revenue requirement figure does not include the Cost of Gas recovered under Rider 2 or any costs recovered under Riders 11, EEP, UEA, VBA, or Rider ICR. *E.g.,* PGL Ex. 6.0 at 2.

The drivers of the cost under-recovery were discussed in detail in direct and rebuttal testimony. PGL Ex. 1.0 at 9-12; NS-PGL Ex. 17.0 at 10-11; PGL Ex. 5.0 at 11-14. The extensive evidence supporting Peoples Gas' rate base, operating expenses, and rate of return is discussed in Sections IV, V, and VI, *infra*, respectively.

Other Parties

[Insert]

Peoples Gas Response

Peoples Gas' detailed rebuttal testimony supported a lower base rate revenue requirement of $601,734,000, meaning its test year cost recovery shortfall under current rates would be decreased to $111,607,000. NS-PGL Ex. Ex.22.1P 2 Corr. at Sched. C-1, line 5. The decreases reflected that Peoples Gas, in its rebuttal, agreed with or accepted in order to narrow the issues, in whole or in part, a number of Staff's and GCI's proposed adjustments, and updated certain items, including , among others, a reduced proposed ROR reflecting a reduced proposed ROE. NS-PGL Ex. 22.0 2 Corr. at 2, 4-5; NS-PGL Ex. 22.2P Corr. at Sched. C-2; NS-PGL Ex. 18.1P.

Finally, Peoples Gas' detailed surrebuttal testimony supported a further-reduced base rate revenue requirement of $601,055,000, meaning its test year cost recovery shortfall under current rates would be decreased to $110,928,000 (the figures including rider and other revenues other than PGA and coal tar revenues are $619,989,000 and $112,610,000, respectively). NS-PGL Ex. 39.0 Corr. at 3; NS-PGL Ex. 39.1P Corr. at Sched. C-1, line 5. The additional reductions reflected that Peoples Gas, in its surrebuttal, again agreed with or accepted, in whole or in part, certain Staff-proposed adjustments and updated certain items. NS-PGL Ex. 39.0 Corr. at 2, 3, 4; NS-PGL Ex. 39.2P Corr. at Sched. C-2.

Commission Analysis and Conclusion

The Commission approves Peoples Gas' final revised revenue requirement. Peoples Gas is entitled to recover these proven costs through its rates. Staff's and GCI's contested proposed adjustments are erroneous and will not be approved, as discussed in Sections IV, V, and VI, *infra*.

IV. RATE BASE

A. Overview/Summary/Totals

1. North Shore

North Shore

In its direct case, North Shore proposed a rate base of $186,897,000, including $422,385,000 of Gross Utility Plant, less $180,540,000 of Accumulated Provision for Depreciation and Amortization (commonly referred to as the "Depreciation Reserve"), and various other additions and subtractions. NS Ex. 7.0 at 4; NS Ex. 7.1 at Sched. B-1.

Other Parties

[Insert]

North Shore Response

In its rebuttal case, North Shore proposed a rate base of $192,783,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part and certain updates. NS-PGL Ex. 23.0 Corr. at 23-24; NS-PGL Ex. 23.1N Corr. (Sched. B-1); NS-PGL Ex. 23.2N Corr. (Sched. B-2).

In its surrrebuttal case, North Shore proposed a rate base of $192,562,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part and certain updates. NS-PGL Ex. 40.0 Corr. at 15; NS-PGL Ex. 40.1N (Sched. B-1); NS-PGL Ex. 40.2N (Sched. B-2).

Commission Analysis and Conclusion

The Commission approves North Shore's final revised rate base. The detailed evidence in the record warrants this conclusion. The remaining contested adjustments proposed by Staff and GCI are erroneous, as discussed below.

2. <u>Peoples Gas</u>

Peoples Gas

In its direct case, Peoples Gas proposed a rate base of $1,415,543,000, including $2,844,667,000 of Gross Utility Plant, less $1,182,971,000 for the Depreciation Reserve, and various other additions and subtractions. Dir., PGL Ex. 7.0 at 4; PGL Ex. 7.1 at Sched. B-1.

Other Parties

[Insert]

Peoples Gas Response

In its rebuttal case, Peoples Gas proposed a rate base of $1,452,914,000, reflecting adjustments proposed by Staff and intervenors that the utility accepted in whole or in part and certain updates. NS-PGL 23.0 Corr. at 23-24; NS-PGL Ex. 23.1P Corr. (Sched. B-1); NS-PGL Ex. 23.2P Corr. (Sched. B-2).

In its surrebuttal case, Peoples Gas in its proposed rate base of $1,472,853,000, reflecting adjustments proposed by Staff and intervenors that the utility accepted in whole or in part, and certain updates. NS-PGL, 40.0 Corr. at 14-15; NS-PGL Ex. 40.1P Corr. (Sched. B-1); NS-PGL Ex. 40.2P Corr. (Sched. B-2).

Commission Analysis and Conclusion

The Commission approves Peoples Gas' final revised rate base. The detailed evidence in the record warrants this conclusion. The remaining contested adjustments proposed by Staff and GCI are erroneous, as discussed below.

B. Uncontested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Natural Gas Prices – Working Capital Allowance – Gas in Storage

The Utilities, Staff, and GCI agree to the Utilities' proposed reductions to the Gas in Storage valuations in rate base in order to reflect an updated gas price. NS-PGL Ex. 23.0 Corr. at 7-8; Staff Ex. 17.0 at 9-10; GCI Ex. 6.0 at 2-3. Therefore, the Commission approves the Utilities' proposed reductions to the Gas in Storage valuations in rate base in order to reflect an updated gas price.

2. Plant

a. Specific Plant Investments – Warehouse at Manlove Field

The Utilities and Staff agreed upon the inclusion of the costs of the following projects in rate base: (1) the costs associated with the Pigging and Well-Head Separator Project #1, (2) the costs associated with the Pigging and Well-Head Separator Project #2, (3) the costs associated with the construction of a new warehouse at Manlove Field, and, (4) the costs associated with the Pipeline Heaters Replacement Project. Staff Ex. 17.0 at 5, 11, 12, 13. These are not contested. Therefore, the Commission approves the inclusion of the costs of these projects in rate base.

b. Pigging Well-Head Separator Project #1

See Section IV.B.2.a, *supra*.

c. Pigging Well-Head Separator Project #2

See Section IV.B.2.a, *supra*.

d. Pipeline Heaters Replacement Project

See Section IV.B.2.a, *supra*.

3. Accumulated Depreciation Expense on Forecasted Additions and Utility Plant in Service – 2010 Actual

The Utilities and Staff have agreed upon the adjusted depreciation reserve amounts for actual 2010 plant-in-service for both Utilities. NS-PGL Exs. 23.4N and 23.4P; Staff Ex. 10.0 at 6. This is not contested. Therefore, the Commission approves the adjusted depreciation reserve amounts for actual 2010 plant-in-service for both Utilities.

4. Accumulated Deferred Income Taxes

a. Bonus Depreciation, Illinois State Income Taxes and Tax Accounting Method Changes

Regarding Accumulated Deferred Income Taxes ("ADIT"), the Utilities and Staff have agreed to adjustments which account for the new State income tax rate and tax accounting method changes, as they relate to bonus depreciation, for both Utilities. NS-PGL Exs. 23.4N and 23.4P; Staff Ex. 10.0 at 6. This is uncontested. Therefore, the Commission approves these adjustments for both Utilities.

b. Use of Average Rate Assumption Method Relating to Health Care Reform Legislation

In his direct testimony, Utilities' witness Mr. Stabile testified that the Utilities propose to re-measure deferred tax balances caused by the enactment of the Health Care Reform Legislation using the average rate assumption method. NS Ex. 10.0 at 2-6; PGL Ex. 10.0 at 2-6. This proposal is uncontested. Therefore, the Commission approves the Utilities' proposed methodology to re-measure deferred tax balances caused by the enactment of the Health Care Reform Legislation.

c. Net Operating Loss – Tax Normalization

The Utilities proposed to calculate their Net Operating Loss ("NOL") at present rates to offset deferred tax liabilities and avoid a normalization violation. A further calculation is needed to reflect NOL normalization based on revenue changes in the final Order. NS-PGL Ex. 23.0 at 6; NS-PGL Ex. 26.0 at 26; NS-PGL Ex. 40.0 at 13-15. This is uncontested. Therefore, the Commission approves the Utilities' proposal.

C. Contested Issues

1. Plant (All Subjects Relate to NS and PGL Unless Otherwise Noted)

a. Forecasted Test Year Capital Additions

(i) Utility Plant in Service

North Shore and Peoples Gas

North Shore and Peoples Gas presented extensive evidence supporting their Utility Plant in Service in rate base, as referenced in Section IV.A.1, *supra*.

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities do not object to Staff's adjustment to reduce the Utilities' forecasted additions to plant-in-service for the years ending December 31, 2011, and December 31, 2012, as corrected by Utilities witness Mr. Hengtgen's surrebuttal testimony. Staff Ex. 1.0 at 15-16; NS-PGL Ex. 40.0 Corr. at 3-4.

GCI's proposed adjustment to 2011-2012 Accelerated Main Replacement Program ("AMRP") additions is without merit, as discussed in Section IV.C.1.a.ii, *infra*.

Commission Analysis and Conclusion

See the Commission Analysis and Conclusion section as set forth in Section IV.C.1.a.ii, *infra*.

(ii)Capital Additions Related to Accelerated <u>Main Replacement – AMRP (PGL)</u>

Other Parties

[Insert]

Peoples Gas Response

GCI witness Mr. Effron's adjustment should be rejected as it is based on a flawed premise that Peoples Gas will not complete the work scheduled for 2011, and thus, this under-spending will carry over into the test year. In surrebuttal testimony, Peoples Gas witness Mr. Hayes explained that Peoples Gas initially treated the 2011 AMRP expenditures of $123.4 million as if they would be expended evenly over the course of 2011 and budgeted accordingly. However, these expenditures instead reflected a bell shape curve, with fewer costs being incurred in the early and late months of the year and the peak expenditures being in the middle months, which represent the peak construction months. NS-PGL Ex. 42.0 at 4. The record demonstrates that for 2011, the first year of the 20 year AMRP, Peoples Gas has experienced the normal transition or "learning curve" with the ramp up of activities such as design, permitting, staffing of key positions, construction contract bidding, etc., that have slightly delayed the expenditures so far this year. *Id.* at 4-5. By the end of May 2011, there has been a ramp-up of the AMRP expenditures which are expected to climb dramatically for the remainder of 2011 and 2012. NS PGL Ex. 24.0 at 6.

Even though fewer costs were expended in the early months of 2011, Peoples Gas fully intends to achieve the forecasted 2011 expenditures for AMRP as is demonstrated by: (1) Peoples Gas has contracted with four installation contractors to install over 180 miles of new mains and over 16,000 services in 2011; and (2) Peoples Gas crews are ramping up to complete over 24,000 meter sets in 2011. Additionally, Peoples Gas states that it has a contingency plan in place should circumstances prevent it from completing this work, which includes the installation of approximately

4 miles of high pressure piping inclusive of the tie-in to the natural gas transmission line along with the necessary valves and regulators. *Id.* at 5.

Furthermore, Peoples Gas argues that GCI's argument that any under spending in 2011 will affect 2012 spending is purely speculation and without merit. 2012, the second year of the AMRP, will benefit from the lessons learned from 2011 and Peoples Gas expects a much earlier start for the 2012 construction year. *Id.* at 5.

Finally, if the Commission determines to approve the GCI adjustment—which Peoples Gas submits it should not—Peoples Gas would have to limit its capital expenditures to what the Commission allows for the 2011-2012 period. Peoples Gas still plans to spend the revised 2011-2012 total amount on AMRP that is reflected (subject to the average rate base method) in its surrebuttal. NS-PGL Ex. 42.0 (entire). However, Peoples Gas cannot do so if that means being denied millions of dollars of recovery of the costs of the AMRP for this period, and instead, in that event, Peoples Gas would have to limit the 2011-2012 expenditures to what the Commission allows, resulting in delay and higher costs. NS-PGL Ex. 17.0 at 14-15. Based on GCI's original proposed reduction of $129 million of AMRP costs (gross amount) in 2011-2012 (GCI Ex. 2.0 Corr. at 6), Peoples Gas would lose approximately $11 million per year until the implementation of rates after its next rate case. NS-PGL Ex. 17.0 at 14. The disallowance of these costs from rate base would delay customer benefits, such as safety and reliability, as described by Mr. Hayes. PGL Ex. 8.0 at 12-13.

Commission Analysis and Conclusion

The Commission agrees with Staff witness Mr. Kahle that his analysis provides a better assessment of the Utilities' performance because it includes all of the Utilities' budgeted capital expenditures rather than a single project as does the analysis of GCI witness Mr. Effron. Further, the Commission finds that the GCI adjustment is not supported by the record. The Utilities have more than amply supported their 2011-2012 AMRP investment figures. Moreover, due to the average rate base method, the rate base already includes only half of the 2012 investments. Therefore, the Commission approves Staff's proposed adjustment as corrected and rejects GCI's proposed disallowance of forecasted additions related to AMRP for 2011 and 2012.

b. <u>Capitalized Incentive Compensation</u> (See also Section V.C.1)

See Section V.C.1.

c. <u>Non-Union Wages</u> (See also Section V.C.2)

See Section V.C.2.

d. Original Cost Determination as to Plant Balances as of December 31, 2009

North Shore and Peoples Gas

The Commission should approve the $411,643,000 original cost of plant for North Shore at December 31, 2009 and the $2,667,949,000 original cost of plant for Peoples Gas at December 31, 2009, as reflected on each utility's Schedule B-5, Page 1 of 2, as the original costs of plant. NS Ex. 7.0 at 15-16; PGL Ex. 7.0 at 17-18; NS-PGL Ex. 23.0 Corr. at 24-25; NS-PGL 40.0 Corr. at 12.

Staff

[Insert]

North Shore and Peoples Gas Response

Staff's proposed adjustment to the original cost finding is inappropriate because incentive compensation is a contested issue in this proceeding and an issue on appeal for both the 2007 and 2009 Utilities rate cases. If the Utilities were to prevail on appeal, the Commission would have inappropriately reduced their original cost of plant. NS-PGL Ex. 23.0 Corr. at 24-25.

However, if the Commission decides to accept Staff's adjustments to the original cost determination, then the Commission's final Order should specify that if a decision in the Appellate Court or another court or a Commission decision on remand or in any other proceeding results in the plant in question being approved, then the original cost amounts should be restored to their full amounts of $2,667,949,000 original cost of plant for Peoples Gas and $411,643,000 original cost of plant for North Shore.

Commission Analysis and Conclusion

The Commission finds that it is inappropriate to decrease the Utilities' original cost determinations relating to capitalized incentive compensation as proposed by Staff. Therefore, the Commission approves the $411,643,000 original cost of plant for North Shore at December 31, 2009 and the $2,667,949,000 original cost of plant for Peoples Gas at December 31, 2009, reflected on each Utility's Schedule B-5, Page 1 of 2, as the original costs of plant.

2. Materials and Supplies – Computation of Associated Accounts Payable

North Shore and Peoples Gas

The Utilities' direct case included in rate base Materials and Supplies offset by the related Accounts Payable. NS. Ex. 7.0 at 7; PGL Ex. 7.0 at 7.

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities did not contest GCI witness Mr. Morgan's methodology to compute accounts payable associated with Materials and Supplies, which is a two-year composite percentage of the monthly debits to materials and supplies accounts that is applied to the test year, as corrected by Utilities witness Mr. Hengtgen. NS-PGL Ex. 23.0 Corr. at 11-12; GCI Ex. 6.0 at 2. Staff's methodology for computing improperly uses a lead time in days from the Cash Working Capital ("CWC") lead-lag study to calculate what Staff refers to as "reasonable level of costs that would be included in Accounts Payable." Staff Ex. 3.0 at 27.

The CWC lead-lag study is prepared to determine the level of cash working capital a utility requires to finance its day to day operations. The CWC requirement is included in a utility's rate base. NS Ex. 7.0 at 16-17; PGL Ex. 7.0 at 18-19. The CWC requirement does not affect any other rate base component. A lead-lag study measures the amount of time in days that on average it takes a utility to pay for its other operation and maintenance expenses, such as Material and Supplies. Thus, the lead-lag study only applies to expenses and not the portion of the purchases that are included in material and supplies and already are a component of rate base. However, the accounts payable offset is intended to measure the amount of materials and supplies, a rate base item, at month end for which payment has not yet been made.

As a result, Staff's calculation computes an amount of accounts payable by utilizing a time period in days. The two are not related and a time period is not an appropriate measure to reflect an amount of accounts payable at month end. NS-PGL Ex. 23.0 Corr. at 12.

Commission Analysis and Conclusion

The Commission finds that GCI witness Mr. Morgan's methodology is more appropriate as it uses a two-year composite percentage of the monthly debits, or monthly increases, recorded to the rate base component, Materials and Supplies. The Commission finds that Staff's methodology to calculate accounts payable associated with Materials and Supplies should not be adopted because the use of the lead-lag study is not proper. Therefore, the Commission adopts the GCI adjustment as corrected by Utilities witness Hengtgen and rejects Staff's proposal.

3. <u>Gas in Storage – Computation of Associated Accounts Payable</u>

North Shore and Peoples Gas

Gas in Storage is an asset in rate base which the Utilities have offset with related accounts payable based on Commission treatment established in their last two rate cases. NS Ex. 7.0 at 7; PGL Ex. 7.0 at 7. Consistent with the methodology that was approved by the Commission in the Utilities' 2009 rate case, the Utilities calculated the associated accounts payable offset amount associated as the net increase in the monthly Gas in Storage balance. NS Ex. 7.0 at 12; PGL Ex. 7.0 at 14.

Other Parties

[Insert]

North Shore and Peoples Gas Response

Staff's computation of associated accounts payable is flawed because it does not reflect that the Utilities' use the Last-In First-Out ("LIFO") method to account for Gas in Storage Inventory. The LIFO accounting method means that as the Utilities purchase gas to serve customers, the last gas in (purchased) is the first gas out (to customers). Thus, based on the LIFO method, the Utilities do not reflect current year gas purchases in inventory until the beginning of the year volume of gas is restored or replenished back into inventory. In other words, as demand for gas exceeds purchases and gas in inventory is withdrawn, gas is restored to previous LIFO layers before current year purchases are reflected in Gas in Storage Inventory. For both Peoples Gas and North Shore, this does not occur in the test year until August. From August to November, an amount for current year purchases is reflected in the end of the month inventory balance. NS-PGL Ex. 23.0 Corr. at 9; NS-PGL Exs. 23.6N and 23.6P. That is consistent with the Utilities' methodology, whereby the average in the increase in test year monthly balances of Gas in Storage is used as the accounts payable offset. In fact, the Utilities' methodology is conservative in that it begins in April 2012 for both Utilities (*see* NS Ex. 7.1 at p. 2; PGL Ex. 7.1 at p. 2) even though the gas purchases are not projected to be recorded to Gas in Storage until August 2012.

However, Staff's methodology calculates accounts payable amounts for all months of the test year except January, 2012. NS-PGL Exs. 23.6N and 23.6P show that for the months January through July and December, the dollar value of gas that comprises the ending balance of Gas in Storage is related to inventory purchased years ago – not the test year. To assign an amount of outstanding accounts payable related to gas that was purchased in years prior to the test year is improper. NS-PGL Ex. 23.0 Corr. at 9.

Further, Staff's reliance on the Ameren Illinois methodology used in its current rate cases, ICC Docket Nos. 11-0279/0281 (cons.), is misplaced because Ameren Illinois uses a different accounting method for Gas in Storage. NS-PGL Ex. 23.0 Corr. at 9-10; NS-PGL Ex. 23.15. Instructive is the methodology used in ICC Docket No. 08-0383, Northern Illinois Gas Company's ("Nicor") last rate case. Nicor, which uses the LIFO accounting method for Gas in Storage, proposed a similar methodology as the Utilities have proposed in this proceeding and it was uncontested in Nicor's rate case. NS-PGL Ex. 23.0 Corr. at 10. *See also Northern Illinois Gas Co.*, ICC Docket No. 08-0363 (Order Mar. 25, 2009), p. 16. Noteworthy is that GCI witness Mr. Morgan proposed a similar adjustment as Staff's regarding associated accounts payable for Gas in Storage. GCI 1.0 Corr. at 10-11. However, upon learning that the Utilities account for Gas in Storage using the LIFO method, Mr. Morgan withdrew his adjustment, stating "Given the Companies' accounting method, my adjustment would be inappropriate." GCI Ex. 6.0 at 2; *see also* NS-PGL Ex. 23.13.

Finally, Staff's calculation here is also flawed because it is based on the lead-lag study. The lead-lag study is prepared to determine the level of Cash Working Capital a utility requires to finance its day to day operations. The CWC requirement is included in a utility's rate base. NS Ex. 7.0 at 16-17; PGL Ex. 7.0 at 18-19. The CWC requirement simply does not affect any other rate base component. A lead-lag study measures the amount of time in days that on average it takes a utility to pay for its gas costs expenses. Thus, the lead-lag study only applies to expenses and <u>not</u> the portion of the purchases that are included in inventory and already are a component of rate base. However, the accounts payable offset is intended to measure the amount of Gas in Storage Inventory, a rate base item, at month end for which payment has not yet been made. As a result, Staff's calculation computes an amount of accounts payable by utilizing a time period in days. The two are not related and a time period is not an appropriate measure to reflect an amount of accounts payable at month end. NS-PGL Ex. 23.0 Corr. at 11.

Commission Analysis and Conclusion

The Commission finds that Staff's methodology to calculate accounts payable associated with Gas in Storage inventory must be rejected for two reasons: (1) it fails to reflect that the Utilities' account for Gas in Storage using the LIFO accounting method; and (2) the use of the lead-lag study is not proper. Therefore, Staff's proposal is without merit and is rejected.

4. <u>Cash Working Capital</u>

North Shore and Peoples Gas

Cash working capital is the amount of funds required to finance the day-to-day operations of a utility. The CWC requirement is included in each of the Utilities' rate bases for ratemaking purposes. NS Ex. 7.0 at 16-17; PGL Ex. 7.0 at 19. 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) lag and lead times associated with the collection and 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. NS Ex. 7.0 at 17; PGL Ex. 7.0 at 20. The Utilities performed a lead-lag study closely conforming to the methodology adopted by the Commission in the 2007 and 2009 rate cases. NS Ex. 7.0 at 18; PGL Ex. 7.0 at 21.

a. Pass-Through Taxes and Energy Assistance Charges

North Shore and Peoples Gas

The only contested aspect of the Utilities' lead-lag cash working capital study relates to pass-through taxes and energy assistance charges. The Utilities add pass-through taxes and energy assistance charges to customer bills and then are required to remit the funds to various local and state governmental agencies. These taxes and 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. NS Ex. 7.0 at 21; PGL Ex. 7.0 at 24. In approving the Utilities' expense leads and revenue lags in the 2009 rate cases, the Commission acknowledged and found that: "If shareholders make a payment because the money has not yet been received from ratepayers, then this amount is appropriately contained in the calculation of cash working capital." *Peoples 2009*, p. 24.

1. Lags for Pass-Through Taxes and Energy Assistance Charges

North Shore and Peoples Gas

In a lead-lag study, the revenue lag measures the number of days from the date service was rendered by the Utilities until the date payment was received from customers and such funds become available to the Utilities. NS Ex. 7.0 at 19; PGL Ex. 7.0 at 22. Pass-through taxes and energy assistance charges are included on the monthly bills and payments are received for these amounts at the same time as all other cash from its customers, therefore the lag for the collection of pass-through taxes and energy assistance charges is identical to the revenue lag. NS Ex. 7.0 at 22; PGL Ex. 7.0 at 25.

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities argue that Staff's proposal to reduce the revenue lag to zero for pass-through taxes and energy assistance charges must be rejected. The Utilities note that the Commission specifically rejected Staff's argument in the Utilities' 2009 rate case, stating:

> The Utilities have appropriately used a methodology that matches what the Commission approved in the Utilities' last rate cases. The evidence shows that the Utilities addressed the actual lags and leads for pass-through taxes in their study. Staff's proposal, however, would in effect find that the Utilities are holding customers' money for 50.3 days (Peoples Gas) and 74.82 days (North Shore). Tr. at 750. The evidence does not

> support this. It appears that Staff's approach improperly ignores the time between when customers are billed for pass through taxes and when the pass through taxes are remitted to the Utilities.

Peoples 2009, p. 24 (emphasis added). Further, Staff agrees that the terms upon which the Utilities remit taxes and charges have not changed since the 2009 rate cases. Kahle Tr. 8/30/11 at 271-272. Staff's methodology must be rejected again as it is not supported by the record.

Staff's argument that because cash received from customers for pass-through taxes is not a payment for utility service, there should be no revenue lag should be rejected for several reasons. First, Staff is incorrect. Utilities witness Mr. Hengtgen explained in his rebuttal testimony the types of pass-through taxes and energy assistance charges and that these taxes and charges were taxes or charges imposed by law on either the Utilities or the customers and were either collected through a separate charge prescribed by law or described within the statute as a charge for utility service. NS-PGL Ex. 23.0 Corr. at 17-18; 305 ILCS 20/13(e) ("The Energy Assistance Charges assessed by electric and gas public utilities shall be considered a charge for public utility service.").

Second, assuming that Staff is correct that there should be no lag because the cash collected for the pass-through taxes and energy assistance charges is not recorded as revenue, and they are not, then there should also be no expense lead because the taxes are not recorded as expense either. Staff's position is flawed as consistent thinking would require that because they are not recorded as expense, they cannot have an expense lead either. The Utilities, in their direct testimony (NS Ex. 7.0 at 20; PGL Ex. 7.0 at 24), and again in rebuttal (NS-PGL Ex. 23.0 at 19-20), 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. That 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. Thus, the Utilities appropriately calculated the lead times based on the timing of cash flows in and cash flows out. NS-PGL Ex. 23.0 at 20. In the 2009 rate cases Order, the Commission acknowledged that "If shareholders make a payment because the money has not yet been received from ratepayers, then this amount is appropriately contained in the calculation of cash working capital." *Peoples 2009*, p. 24. Staff does not disagree. Kahle Tr. 8/30/11 at 269-270. However, Staff continues to eliminate the cash flow in part of the timing difference but does not correct or adjust downward the lead (cash flow out). Staff's proposal would indicate that the Utilities collect and hold most of the pass through taxes and energy assistance charges for an extremely long period time before remitting them to the appropriate taxing jurisdiction, which is simply not accurate. Furthermore, under Staff's proposal, the Utilities would not be in compliance with the appropriate statutes and ordinances governing the payment of the pass-through taxes and energy assistance charges. NS-PGL Ex. 23.0 Corr. at 20.

Third, Staff argues that the Commission's decisions on this issue have "evolved" based on its Orders in the following rate cases: *Nicor 2008*; *Ameren Illinois*, ICC Docket Nos. 09-0306/0307/0311 (cons.) (Order April 29, 2010) ("*Ameren 2009*"); and *Commonwealth Edison Co.*, ICC Docket No. 10-0467 (Order May 24, 2010) ("*ComEd 2010*"). However, the Commission in the Utilities' 2009 rate cases Order found that:

> This is a factual question that rests on when a utility must make certain payments, such as taxes, and when it receives the cash from ratepayers to the make the payments. Whether the payments are based on estimate or actual cash receipts does not matter. If shareholders make a payment because the money has not yet been received from ratepayers, then this amount is appropriately contained in the calculation of cash working capital. Lead lag studies are the method by which this is determined. <u>It is to be expected that each utility's lead-lag study will show different results and, thus, the decision in *Nicor 2008* is not controlling.</u>

Peoples 2009, p. 24 (emphasis added). Thus, because it is a factual question as to when a utility must make certain payments, such as taxes, and when it receives cash from customers to make payments, the decisions in *Nicor 2008*, *Ameren 2009*, and *ComEd 2010* are not controlling here. It is true that the companies in *Nicor 2008*, *Ameren 2009*, and *ComEd 2010* are utilities, a gas utility, a combination gas and electric utility, and an electric utility, respectively. However, electric utilities have some different types of taxes imposed on them or their customers, which have different requirements than the taxes being at issue in this proceeding. Further, each of these utilities operates in different parts of the State indicating that there are different municipal utility taxes imposed on them or their customers. Finally, not all utilities remit these types of taxes on the same basis. For example, unlike other utilities, Peoples Gas and North Shore remit these taxes based on estimated collections based on an agreement that Peoples Gas has with the City of Chicago. NS-PGL Ex. 40.0 Corr. at 10-11. Despite asserting that the Utilities "process pass-through taxes in the same manner" as the utilities in *Nicor 2008*, *Ameren 2009*, and *ComEd 2010* (Staff Ex. 10.0 Corr. at 10), Staff acknowledged he did not compare the local laws or municipal agreements to which Nicor, Ameren or ComEd on the one hand and the Utilities on the other hand are subject. Kahle Tr. 8/30/11 at 274.

Commission Analysis and Conclusion

Staff concedes that the terms upon which the Utilities remit taxes and charges have not changed since the 2009 rate cases. The Commission declines to adopt Staff's use of zero revenue lag days as there is no support in the record for this conclusion or result. Further, Staff's proposal is contrary to the Commission's conclusion in the 2009 rate cases Order and Staff has provided no basis for a change. Moreover, Staff's theory about what is or is not a utility service by some definition does not alter the reality of the Utilities' cash flows in light of their legal obligations relating to these items, and is erroneous in any event. The Commission recognizes that while Staff's methodology might or might not have been appropriate in some other utilities' rate cases, it does not reflect the Utilities' facts here.

2. Leads for Pass-Through Taxes and Energy Assistance Charges

North Shore and Peoples Gas

An expense lead represents the time between when a good is received or a service is provided and when the Utilities pay for that good or service. NS Ex. 7.0 at 24; PGL Ex. 7.0 at 27.

Staff

[Insert]

North Shore and Peoples Gas Response

Although Staff witness Mr. Kahle initially agreed with the Utilities' calculation of expense leads for pass-through taxes and energy assistance charges, in rebuttal testimony, he revised the expense leads for three items, including Energy Assistance Charges, Gross Receipts/Municipal Utility and City of Chicago Gas Use Taxes, because Utilities witness Mr. Hengtgen "offered a revised number of lead days that [the Utilities] collect[] these pass-through taxes before remitting." Tr. 8/30/11 at 265; Staff Ex. 10.0 Corr. at 7-8. To support his calculations, Mr. Kahle relies on lines 442-451 on page 21 of Mr. Hengtgen's rebuttal testimony (NS-PGL Ex. 23.0 Corr.). Tr. 8/30/11 at 266. However, nowhere in Mr. Hengtgen's direct, rebuttal, or surrebuttal testimonies does he offer a revised number of lead days that the Utilities collect these pass-through taxes and energy assistance charges before remitting. In fact, the testimony upon which Mr. Kahle relies is actually a criticism of Staff's methodology for calculating revenue lag days for pass through taxes. Mr. Kahle acknowledged on cross examination that he "interpreted [Mr. Hengtgen's testimony] as being an altered calculation of the expense lead days" and that Mr. Hengtgen did not revise lead days for these taxes. *Id*. at 266-267.

Commission Analysis and Conclusion

The Commission also declines to adopt Staff's proposal to revise expense lead days for three items, including Energy Assistance Charges, Gross Receipts/Municipal Utility and City of Chicago Gas Use Taxes, as it is not supported by the record and is based on Staff's misinterpretation of the Utilities' rebuttal testimony.

For these reasons, the Commission approves the lags and leads for pass-through taxes and energy assistance charges proposed by the Utilities. Therefore, the Commission finds that the Utilities' proposed net working capital amount is reasonable and appropriate, and is consistent with the treatment in the 2009 rate cases Order.

b. <u>Prepayments (Uncontested)</u>

GCI witness Mr. Morgan and Staff witness Mr. Kahle each proposed a change to the collection lag with respect to prepayments. GCI Ex. 1.0 Corr. at 7-8; Staff Ex. 1.0 at 9-10. In rebuttal testimony, Utilities witness Mr. Hengtgen agreed that an adjustment to the collection lag was appropriate and accepted Staff's adjustment. Mr. Morgan accepted the adjustment in rebuttal testimony. GCI Ex. 6.0 at 3. Therefore, the Commission approves the adjustment to the collection lag with respect to prepayments as proposed by Staff and accepted by the Utilities.

c. <u>All Other (Uncontested)</u>

The Utilities, Staff, and GCI agree that the final amount of the Utilities' CWC requirements should be determined based on the revenue and expense levels ultimately approved by the Commission in this proceeding. NS-PGL Ex. 23.0 Corr. at 15; Staff Ex. 10.0 Corr. at 8; GCI Ex. 6.0 at 3. Therefore, the Commission determines the final amount of the Utilities' CWC requirements based on the revenue and expense levels approved by the Commission elsewhere in this Order.

5. <u>Retirement Benefits, Net</u>

North Shore and Peoples Gas

It is undisputed that "Retirement Benefits, Net" for each utility is the sum of its pension asset (its prepaid pension expense) less its "OPEB" (other post-employment benefits) (also sometimes referred to as "post-retirement welfare") liability. NS Ex. 7.1 at Sched. B-1.2; PGL Ex. 7.1 at Sched. B-1.2; NS Ex. 11.0 at 12; PGL Ex. 11.0 at 12; GCI Ex. 2.0 at 8.

The Utilities request Commission approval of "Retirement Benefits, Net" of $2,804,000 for North Shore and $68,887,000 for Peoples Gas (updated figures as of rebuttal and surrebuttal). NS-PGL Ex. 40.1N, line 7; NS-PGL Ex. 40.1P, line 7. In other words, the Utilities should be allowed to recover the carrying costs of their prepaid pension expense. That is what including their Retirement Benefits, Net, in rate base, would do, while at the same subtracting their OPEB liabilities. The Utilities submit that that would be the correct ruling given the evidence in the record and the applicable law.

In the alternative, North Shore requests that the Commission (1) approve inclusion in North Shore's rate base of its recent pension contributions from internally generated sources, $4,001,111 and $11,139,238 in 2009 and 2010, respectively, NS Ex. 11.0 at 7, less its OPEB liability; or (2) allow North Shore to recover as an income item the annual customer benefit (in terms of reduced pension expense in the utility's revenue requirement) of those two pension contributions, *i.e.,* $1,260,000 per year, *id*., while still including the OPEB liability in rate base.

Finally, further in the alternative, the Utilities request that the Commission remove from rate base each utility's pension asset and its OPEB liability, *i.e.,* its Retirement Benefits, Net, to be fair and consistent.

Other Parties

[Insert]

North Shore and Peoples Gas Response

The evidence establishes new factual points supporting inclusion of the pension assets in rate base. The reason the Commission in the 2007 and 2009 rate cases excluded from rate base Peoples Gas' pension asset and excluded the alternative of the Utilities' pension contributions, and the reason Staff and GCI in the instant cases propose the exclusion in rate base of the Utilities' pension assets and North Shore's pension contributions, is the theory that the pension assets and contributions were not funded by investors but instead by customers because the source of funds was funds from net cash from operating activities (in particular, the collection of customers' utility bills). *Peoples 2007*, p. 36; *Peoples 2009*, pp. 35-37; Staff Ex. 3.0 at 3–7; Staff Ex. 12.0 at 3–4; *see also* GCI Ex. 2.0 at 8–10; GCI Ex. 7.0 at 8–9.

However, the evidence in the instant cases, including new facts elicited by Staff at the evidentiary hearing, does not permit a finding that the pension assets and contributions were not funded by investors. In the 2007 and 2009 rate cases (and some other cases), and in Ms. Ebrey's reasoning, the fact that a utility makes pension contributions and creates a pension asset using funds from net cash from operating activities has been taken to mean that none of those funds constitute capital of the utility. However, Utilities witness Ms. Phillips pointed out in her rebuttal testimony that "net cash from operating activities includes the portion of what customers pay on their bills for return of and on rate base as approved during the ratemaking process." NS-PGL Ex. 27.0 at 9. In other words, part of what customers pay is the return of and on past capital investments of the utilities ("return of" being depreciation and amortization expense, and "return on" being the rate of return on rate base reflected as net income in the revenue requirement). The fact that the utility collects return of and on its capital investments does not mean that those collected funds then are not capital of the utility. Neither the facts nor logic supports that inference, which was refuted by Ms. Phillips. Moreover, the cross-examination of Utilities witness Ms. Gast by Staff showed another reason that inference is incorrect, *i.e.,* the portion of funds derived from collecting customers' utility bills that ends up as net income is retained earnings and thus is a part of equity. Gast Tr. 8/31/11 at 399-400. These facts preclude any finding that the use of a portion of net cash from operating activities to make pension contributions and create a pension asset is not an expenditure of capital. These facts were not addressed in the 2007 and 2009 rate cases.

Ms. Ebrey's rebuttal did attempt to respond to Ms. Phillips' rebuttal, but, in essence, all that Ms. Ebrey did was claim that Ms. Phillips had not shown a change in facts since the 2007 and 2009 rate cases and state that the additional information that Ms. Phillips had supplied did not contradict North Shore's prior data request response about the source of funds for its 2009 and 2010 pension contributions. Staff Ex. 12.0 at 3–4. Neither point refutes or even undercuts what Ms. Phillips said. Moreover, Ms. Phillips' point about a portion of funds collected from customers being return of and on capital investments of the utility may not be a change in circumstances, but it is a new fact that was not in evidence and thus was not addressed by the Commission's Orders in the prior cases.

Mr. Effron agreed that, by definition, customers' payments of their utility bills cannot be direct contributions to a utility's pension trust. Tr. 8/30/11 at 205.

Further proof that it is erroneous to infer that use of funds from operations cannot be a use of capital is found in the facts that the pension assets are part of the Utilities' balance sheets and, with respect to defined benefit plans, which is what is involved here, that the utilities own the assets, with the employees being the beneficiaries of the trust. NS-PGL Ex. 27.0 at 9. These two facts were raised in the past cases, but they remain uncontested.

Exclusion of the pension assets from rate base would be contrary to law. The premise that customers, by paying utility bills, somehow should be treated as if they had paid for the utility's assets, also is wrong as a matter of law. Utility customers pay for service, not for the property used to render it. *Board of Public Utility Commissioners, et al. v. New York Tel. Co.*, 271 U.S. 23 (1926).

Moreover, the Supreme Court of Illinois previously has rejected a claim that a utility's rate base should be reduced on the theory that part of it was the product of customer-supplied funds. In *Citizens Utilities Co. of Illinois v. Illinois Commerce Comm'n*, 124 Ill. 2d 195, 529 N.E.2d 510 (1988), the Commission in a rate case had made a $4,253,953 reduction in plant in a utility's rate base and reduced its depreciation expenses by $403,432, a total of $4,657,385, where the utility's existing rates had incorporated a level of income taxes that resulted in collecting through rates $4,657,385 more for income taxes that the utility actually had paid. *Citizens Utilities*, 124 Ill. 2d at 201-202, 529 N.E.2d at 513. The Commission, on appeal, sought to justify the reductions on the basis that the funds that paid for the plant were not investor-supplied but rather were customer-supplied, by virtue of the income tax over-recovery. *Citizens Utilities*, 124 Ill. 2d at 203, 204-205, 529 N.E.2d at 513, 514-515. The Supreme Court reversed, finding that the Commission's reductions constituted improper retroactive ratemaking. *Citizens Utilities*, 124 Ill. 2d at 203, 206-207, 210-211, 529 N.E.2d at 515-516, 517 (citing, *inter alia*, *Mandel Brothers, Inc. v. Chicago Tunnel Terminal Co.*, 2 Ill. 2d 205, 117 N.E.2d 774 (1954)). The Supreme Court stated in part:

> The Commission would derive from those cases the rule that a public utility's investors are not entitled to earn a return on sums that may be characterized as capital contributions by customers. We would note, however, that there was no contention made in either of the cited cases

> concerning retroactive ratemaking. The amounts at issue here were recovered by Citizens in past ratemaking orders as part of its income tax expense, and the validity of those orders cannot now be questioned.

Citizens Utilities, 124 Ill. 2d at 212, 529 N.E.2d at 518. Although the circumstances are not identical, here, too, the Staff and GCI positions are based on the premise that customers' payments of bills under past rates mean that customers supplied the funds used to pay for the asset and, therefore, the utility should earn no return on the asset. That is inconsistent with *Citizens Utilities*.

The decision in *Commonwealth Edison Co. v. Illinois Commerce Comm'n*, 398 Ill. App. 3d 510, 924 N.E.2d 1065 (2d Dist. 2009) ("*ComEd 2009*"), does not support denying the Utilities recovery of the carrying costs of their prepaid pension expense. In the rate case Order on Rehearing underlying the relevant portion of that Second District decision, the Commission had excluded Commonwealth Edison Company's ("ComEd") pension asset from rate base but allowed ComEd to recover a return at its cost of long-term debt on an $803 million contribution to the pension plan that was made in 2005 using funds supplied by ComEd's ultimate parent company. *ComEd 2009*, 398 Ill. App. 3d at 519-520, 924 N.E.2d at 1079. ComEd appealed, arguing that it should be allowed a return based on its overall cost of capital, not its cost of long-term debt, but the Second District affirmed, accepting the Commission's argument that ComEd has failed to carry its burden of proving that recovery of the $803 million contribution at ComEd's full cost of capital was reasonable or that there was not a less expensive alternative to funding the contribution than that full cost of capital. *ComEd 2009*, 398 Ill. App. 3d at 521-522, 924 N.E.2d at 1080. Thus, the question on appeal in *ComEd 2009* did not revolve around whether the funds used to contribute to the pension plan were investor-supplied, but around whether financing the contribution at the utility's full cost of capital, rather than its cost of long-term debt, was proven to be reasonable. The fact that the ComEd pension contribution was funded by its ultimate parent company does not warrant excluding the Utilities' pension assets from rate base. As discussed above, the facts of the instant cases do not permit the conclusion that the funding of the pension contributions and pension assets are customer-supplied.

<u>Alternatively, North Shore Should Recover a Return on its 2009 and 2010 Pension Contributions</u>. Although the facts and law support inclusion of the Utilities' pension assets in rate base (*i.e*., recovery of carrying costs on their prepaid pension expense), in the alternative, as to North Shore, the utility should be allowed to include its 2009 and 2010 pension contributions in rate base or, alternatively, to recover the annual customer benefit of the contributions.

In addition to the facts referenced above, the Utilities showed that, with respect to North Shore's 2009 and 2010 pension contributions, the level of pension expense in the approved revenue requirement set in the 2009 rate cases was about $2.9 million per year, much less than the $4,001,111 and $11,139,238 that North Shore contributed in 2009 and 2010, respectively. NS-PGL Ex. 27.0 at 10.

The theory that customers somehow were funding the 2009 and 2010 North Shore pension contributions is fallacious for another reason. Neither of the Utilities has recovered its approved rate of return on common equity since 2003. NS Ex. 1.0 at 4; PGL Ex. 1.0 at 4. Thus, customers were not paying the utility's total costs of service, and it is not logical or fair to infer that they nonetheless were funding these pension contributions.

Finally, in ComEd's 2010 rate case, the Commission approved ComEd's recovery of costs relating to its 2009 pension contribution, which was shown to be funded using internally generated funds, although the recovery was set at the level of annual customer benefit, while the recovery of ComEd's 2005 pension contribution was continued based on a debt rate of return but reduced on an amortization theory. *ComEd 2010* at 50-51, 98.

Accordingly, North Shore should recover the carrying costs of its 2009 and 2010 pension contributions by including them in rate base or, alternatively, should recover as an income item the annual customer benefit (in terms of reduced pension expense in the utility's revenue requirement) of those two pension contributions, *i.e.,* $1,260,000 per year. In either scenario, the OPEB liability still would be included in rate base.

<u>Alternatively, If the Pensions Assets and Contributions Are Excluded from Rate Base, then the OPEB Liabilities Also Should Be Excluded</u>. Finally, in the alternative, if North Shore and Peoples Gas are not allowed to recover the carrying costs of their prepaid pension expense, or, in North Shore's case, even to earn a recovery as its 2009 and 2010 pension contributions, then their OPEB liabilities should not be included in rate base, either. The pension assets / contributions and OPEB liabilities are similar in nature and should be treated on a consistent basis. NS-PGL Ex. 27.0 at 2, 12. The Commission did not so rule in the 2007 and 2009 rate cases, but there is no valid factual or legal reason for disparate treatment of these items.

Commission Analysis and Conclusion

The Commission rejects the proposals of Staff and GCI in the instant cases to exclude in rate base the Utilities' pension assets and North Shore's pension contributions. Although the Commission has previously excluded pension assets from rate base, the evidence in the instant cases establishes new factual points supporting inclusion of the pension assets in the Utilities' rate base. Specifically, the evidence shows that net cash from operating activities includes the portion of what customers pay on their bills for return of and on rate base as approved during the ratemaking process and the portion of funds derived from collecting customers' utility bills that ends up as net income is retained earnings and thus is a part of equity. These facts, which were not addressed in the 2007 and 2009 rate cases, preclude any finding that the use of a portion of net cash from operating activities to make pension contributions and create a pension asset is not an expenditure of capital. The Commission also finds that exclusion of the pension assets from rate base would be contrary to law on this record. For these reasons, the Commission concludes that the Utilities may recover the carrying costs of their prepaid pension expense by including their Retirement Benefits, Net, in rate base, while at the same time subtracting their OPEB liabilities.

Alternative A

The Commission does not adopt the Utilities' proposal to include their pension assets in rate base, but approves the alternative of inclusion in rate base of North Shore's pension contributions. For the reasons provided by the Utilities, the Commission approves inclusion in North Shore's rate base of its recent pension contributions from internally generated sources, $4,001,111 and $11,139,238 in 2009 and 2010, respectively, less its OPEB liability.

Alternative B

The Commission does not adopt the Utilities' proposal to include their pension assets in rate base, but approves the alternative of inclusion in rate base of North Shore's pension contributions. For the reasons provided by the Utilities, the Commission approves North Shore's recovery as an income item of the annual customer benefit (in terms of reduced pension expense in the utility's revenue requirement) of its pension contributions in 2009 and 2010, *i.e.,* $1,260,000 per year, while still including the OPEB liability in rate base.

Alternative C

The Commission adopts the proposals of Staff and GCI in the instant cases to exclude from rate base the Utilities' pension assets and North Shore's pension contributions. The Commission further concludes, however, that it is appropriate, for the reasons provided by the Utilities, to remove from rate base each utility's OPEB liability, to be fair and consistent.

6. Accumulated Deferred Income Taxes

a. 50/50 Sharing Related to Tax Accounting Method Changes

North Shore and Peoples Gas

The Utilities elected two tax accounting method changes: (1) a change in method of accounting related to the determination of unit of property used for repairs and retirements ("Repairs Change"); and (2) a non-automatic change to the capitalization of certain indirect and overhead costs ("Overhead Change"). Both of these tax accounting method changes are not final and are still subject to final rulings by the Internal Revenue Service ("IRS"). Because approval of these tax accounting method changes is far from certain and in the near term carries significantly greater risk than normal issues, the Utilities proposed that the benefits associated with the change be shared 50/50 with their customers. NS Ex. 7.0 at 14-15; PGL Ex. 7.0 at 16-17; NS-PGL Ex. 23.0 Corr. at 12-14.

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Repairs and Overhead Changes are addressed further, specifically, below.

To not recognize that a substantial risk exists with North Shore's and Peoples Gas' Repairs Change and Overhead Change would send a chilling effect to utilities in the future in making such elections before guidance from the Treasury Department and IRS is final. As Mr. Hengtgen explained, when a utility takes a tax deduction and reflects the impact of the deduction in its financial statements, the benefits of that deduction will inevitably be conveyed to customers through reduced rates. However, to the extent an election is subject to a final determination after audit or other Treasury action or law change that reverses a utility's position, it usually results in a utility returning the benefit without the ability to recover equivalent amounts from customers. NS Ex. 7.0 at 14-15; PGL Ex. 7.0 at 17. The Utilities, having made these elections, simply would like to share, 50/50, the risks as well as the benefits with the customers. Further, Staff agrees that the Utilities' sharing proposal is appropriate. As Staff witness Mr. Kahle states:

> The Commission should not discourage utilities from taking tax positions that have some risk associated with them when such positions are appropriate and could benefit ratepayers. …
>
> If the Commission adopted a policy of deducting 100% of the benefits of such tax positions from rate base, the Commission would essentially be assuming that utilities prevail in every instance. Given the doubtfulness of utilities prevailing in every such tax position, the Companies' 50/50 split proposal seems reasonable.

Staff Ex. 10.0 Corr. at 24.

(i) <u>Repairs Change</u>

Other Parties

[Insert]

North Shore and Peoples Gas Response

GCI witness Mr. Morgan errs in claiming that sharing the benefit related to the Repairs Change is unnecessary because there is no significant IRS audit risk. GCI Ex. 1.0 Corr. at 13–14. The Repairs Change relates to the determination of unit of property used for repairs and retirements. NS Ex. 10.0 at 6-7; PGL Ex. 7.0 at 6-7. As Utilities witness Mr. Stabile testifies, the change in tax accounting method is based on

Internal Revenue Code ("IRC") Section 263 which provides: "No deduction shall be allowed for…Any amount paid out for new buildings or permanent improvements or betterments made to increase the value of any property or estate." *Id.* at 7. The Proposed Treasury Regulations issued under this section in 2006 and then again in 2008 provide more detail and generally attempt to define a "unit of property." NS-PGL Ex. 26.0 at 5. Neither the 2006 proposed regulations nor the 2008 re-proposed regulations can be relied upon. Even if they could be relied upon, neither the 2006 nor the 2008 proposed regulations included a definition of a unit of property for network assets. As Mr. Stabile explains, because of the complexity of the issue, the Treasury Department and the IRS have encouraged individual industries to work separately within the confines of the Industry Issue Resolution ("IIR") program. The natural gas industry, through the American Gas Association and Interstate Natural Gas Association of America, has only in May 2011 initiated the IIR process for the industry. However, even if the IIR process is successful, no individual company's method will necessarily be the same as the IIR result or the final Treasury regulations issued under IRC Section 263, which would render IIR guidance null and void. Thus, until final regulations are issued or the IIR process is completed, the Utilities' tax accounting change methodology could vary significantly from the IIR resolution or ultimately the Treasury Department's final regulation; thus, there is significant risk. NS-PGL Ex. 26.0 at 7-8. Even though more utilities have opted to make this election, it in no way lessens this risk – either a utility's methodology will comply with the IRS final regulations 100% or 0% or someplace in the middle.

Further, an IRS audit involves more than simply finding math errors; IRS audits focus on issues. NS-PGL Ex. 26.0 at 9. Even if the unit of property is reasonable and a company has applied that unit of property correctly, the IRS can still challenge a lot of judgment and factual information, such as whether amounts incurred that materially increase the value or substantially prolong the useful life of any unit of property, adapt the property for a new use, or as part of a plan of rehabilitation, modernization, or improvement to any unit of property have been improperly expensed as a repair. The audit risks in a post-change environment are going to be extremely significant until the IIR is concluded and final regulations issued. *Id.* at 9.

Finally, the Commission has addressed the risk associated with the Repairs Change. In ComEd's 2010 rate case, ICC Docket No. 10-0467, Illinois Attorney General and Citizens Utility Board witness Mr. Effron made an accounting reserve and refunds proposal reflecting the Repairs Change in ADIT, even though ComEd had not yet made an election. *ComEd 2010* at 114. In its final Order, the Commission stated, with respect to ComEd's decision not to elect to make the Repairs Change:

> The Commission cannot conclude that ComEd's cautious behavior with the IRS, without more, is an act of imprudence. The Commission also cannot conclude that only ComEd's shareholder will benefit when and if ComEd elects to use this new tax procedure. As Staff points out, when the IRS issues guidelines on this new procedure, and when ComEd avails itself of this procedure, (providing it proves to be beneficial) ratepayers will

> benefit in the future. Additionally, ComEd used a historic test year. As Staff points out, any change regarding the IRS will not occur during the test year. The Commission therefore declines to adjust ComEd's rate base in the manner that Mr. Effron recommends.

ComEd 2010 at 114. If the Commission recognized that there were risks to ComEd, and that the issue had not developed to a more certain level, it is clear that the Utilities likewise have risk with the method changes.

Therefore, the 50/50 sharing of the benefit associated with the Repairs Change is appropriate and Mr. Morgan's arguments are without merit.

(ii) Overhead Change

Other Parties

[Insert]

North Shore and Peoples Gas Response

GCI witness Mr. Effron errs in proposing to reflect 100% of the benefit associated with the Overhead Change in ADIT because he claims that the associated risk is not significant. GCI Ex. 2.0 at 11–13. As Utilities witness Mr. Stabile explained, the Overhead Change has its genesis in the Simplified Service Cost Method ("SSCM") contained in the Treasury Regulations relating to IRC Section 263A, Uniform Capitalization Rules. In 2001, utilities began to elect the SSCM, which at the time could be made automatically. However, by 2003 as the number of utilities making the election increased, the IRS removed this election from the list of elections that could be made automatically and ultimately changed the applicable regulations disallowing the use of SSCM for any property with a life of more than three years. The implementation of the revised regulations disallowing use of the SSCM by utilities was abnormally harsh in that it required an immediate change in accounting in the middle of a tax year with no estimated payment relief. NS-PGL 26.0 at 10-12.

Further, the IRS has designated this election a Tier 1 issue. The Large Business and International ("LB&I") Division of the IRS adopted a compliance issue tiering strategy in 2006 to ensure that high-risk compliance issues are properly addressed and treated consistently across the division for all LB&I taxpayers that are involved in the issue. Thus, it provides a consistent framework for identifying, prioritizing and addressing <u>significant</u> <u>compliance</u> <u>risks</u> in a nationally coordinated manner. There are three tiers in the strategy, Tier I, Tier II and Tier III. Tier I is defined as follows:

> **"Tier I - High Strategic Importance**. Tier I issues are of high strategic importance to LB&I and have significant impact on one or more Industries. Tier I issues could include areas involving a large number of taxpayers, significant dollar risk, substantial compliance risk or high visibility, where there are established legal positions and/or LB&I direction.

> Tier I includes listed transactions as well as other "high-risk" transactions and issues that represent LB&I's highest compliance priorities."

NS-PGL 26.0 at 10-12. Thus, Mr. Effron's claim that there is no substantial risk is baseless because by definition, as a Tier 1 issue, the Overhead Change involves "'high-risk' transactions and issues that represent LB&I's highest compliance priorities." Therefore, the 50/50 sharing of the benefit associated with the Overhead Change is appropriate and Mr. Effron's arguments are without merit.

Commission Analysis and Conclusion

The Commission approves the Utilities' proposal to share, 50/50, the benefits associated with the Repairs Change and the Overhead Change. The record demonstrates that the Utilities' proposal is reasonable and appropriate, and fair, and is supported by Staff. The Commission rejects the GCI assertions against the Utilities' proposal as without merit because substantial risk exists with each election. Moreover, a contrary finding would unwisely create a chilling effect with respect to utility tax elections, which would not be in the long-term interests of customers or utilities.

b. <u>Derivative Adjustments from Contested Adjustments</u>

The Utilities' original Schedule B-9's show the projected balances of Accumulated Deferred Income Taxes at December 31, 2011 and December 31, 2012, and the average amounts for the test year. NS Ex. 7.0 at 12; PGL Ex. 7.0 at 15. Other than the contested issues discussed above and derivative adjustments from contested plant adjustments, these figures were not disputed by any party. The Utilities' final amounts are shown in NS-PGL Ex. 40.1N and 40.1P Corr. The Commission finds the figures in NS-PGL Ex. 40.1N and 40.1P Corr. reasonable and appropriate subject to the derivative impacts of the Commission's rulings on the applicable contested adjustments discussed elsewhere in this Order.

D. Accumulated Depreciation (Uncontested Except for <u>Derivative Adjustments from Contested Adjustments)</u>

The Utilities' original Schedule B-6s show the projected balances of Accumulated Depreciation at December 31, 2011, and December 31, 2012. NS Ex. 7.0 at 10; PGL Ex. 7.0 at 12–13. Other than derivative adjustments from contested plant adjustments, these figures were not disputed by any party. The Utilities' final amounts are shown in NS-PGL Ex. 40.1N and 40.1P Corr. The Commission finds the figures in NS-PGL Ex. 40.1N and 40.1P Corr. reasonable and appropriate subject to the derivative impacts of the Commission's rulings on the applicable contested adjustments discussed elsewhere in this Order.

V. OPERATING EXPENSES

A. Overview/Summary/Totals

1 and 2. North Shore and Peoples Gas

North Shore and Peoples Gas

North Shore's direct case presented base rate operating expenses of $68,700,000. NS Ex. 6.1. Peoples Gas' direct case presented base rate operating expenses of $512,602,000. PGL Ex. 6.1.

North Shore's and Peoples' Gas operating expenses are supported by extensive, detailed evidence, including the testimony of four witnesses on the following topics: (1) the test year, the overall revenue requirement, operating expenses, operating income, and the Gross Revenue Conversion Factor, and underlying calculations and support of various components of operating expenses; (2) the test year forecast and associated "Part 285" Schedules, significant variances year over year from prior years to the test year in amounts recorded in operating expense Accounts, depreciation and amortization expense, taxes other than income taxes expense, and intercompany costs; (3) incentive compensation program expenses; and (4) employee benefits operating expenses, including pensions, OPEB, group insurance, and Integrys Business Support ("IBS")-billed benefits, as cited below.

Other Parties

[Insert]

North Shore and Peoples Gas

North Shore in its surrebuttal testimony presented revised base rate operating expenses of $68,706,000, reflecting adjustments proposed by Staff and GCI with which the utility agreed or accepted in whole or in part and certain updates. NS-PGL Exs. 39.1N, 39.2N.

Peoples Gas in its surrebuttal testimony presented revised base rate operating expenses of $500,540,000, reflecting adjustments proposed by Staff and GCI with which the utility agreed or accepted in whole or in part and certain updates. NS-PGL Exs. 39.1P Corr., 39.2P Corr.

North Shore's and Peoples Gas' operating expenses are supported by extensive, detailed evidence, including the testimony of four witnesses on the following topics: (1) the test year, the overall revenue requirement, operating expenses, operating income, and the Gross Revenue Conversion Factor, and underlying calculations and support of various components of operating expenses; (2) the test year forecast and associated "Part 285" Schedules, significant variances year over year from prior years to the test year in amounts recorded in operating expense Accounts, depreciation and amortization expense, taxes other than income taxes expense, and intercompany costs; (3) incentive compensation program expenses; and (4) employee benefits operating expenses, including pensions, OPEB, group insurance, and Integrys Business Support ("IBS")-billed benefits. NS Ex. 6.0, NS Ex. 6.1, NS Ex. 6.2 Public/Conf., PGL Ex. 6.0, PGL Ex. 6.1, PGL Ex. 6.2 Public/Conf.; NS-PGL Ex. 22.0 2Corr., NS-PGL Ex. 22.1N 2 Corr., NS-PGL Ex. 22.2N 2 Corr., NS-PGL Ex. 22.3N 2Corr., NS-PGL Ex. 22.4N 2 Corr., NS-PGL Ex. 22.5N, NS-PGL Ex. 22.6N, NS-PGL Ex. 22.7N, NS-PGL Ex. 22.8N 2 Corr., NS-PGL Ex. 22.9N 2 Corr., NS-PGL Ex. 22.10N 2 Corr., NS-PGL Ex. 22.11N, NS-PGL Ex. 22.1P 2 Corr., NS-PGL Ex. 22.2P 2 Corr., NS-PGL Ex. 22.3P 2 Corr., NS-PGL Ex. 22.4P 2 Corr., NS-PGL Ex. 22.5P, NS-PGL Ex. 22.6P, NS-PGL Ex. 22.7P, NS-PGL Ex. 22.8P 2 Corr., NS-PGL Ex. 22.9P 2 Corr., NS-PGL Ex. 22.10P 2 Corr., NS-PGL Ex. 22.11P; NS-PGL Ex. 39.0 Corr., NS-PGL Ex. 39.1N, NS-PGL Ex. 39.2N, NS-PGL Ex. 39.3N, NS-PGL Ex. 39.4N Public/Conf., NS-PGL Ex. 39.5N, NS-PGL Ex. 39.6N, NS-PGL Ex. 39.7N, NS-PGL Ex. 39.8N, NS-PGL Ex. 39.1P Corr., NS-PGL Ex. 39.2P Corr., NS-PGL Ex. 39.3P, NS-PGL Ex. 39.4P Public/Conf., NS-PGL Ex. 39.5P Corr., NS-PGL Ex. 39.6P Corr., NS-PGL Ex. 39.7P Corr., NS-PGL Ex. 39.8P, NS-PGL Ex. 39.9 Public/Conf.; NS Ex. 5.0, NS Ex. 5.1, PGL Ex. 5.0, PGL Ex. 5.1; NS-PGL Ex. 21.0 Corr., NS-PGL Ex. 21.1N, NS-PGL Ex. 21.1P, NS-PGL Ex. 21.2N, NS-PGL Ex. 21.2P, NS-PGL Ex. 21.3N, NS-PGL Ex. 21.3P, NS-PGL Ex. 21.4P; NS-PGL Ex. 38.0, NS-PGL Ex. 38.1P, NS-PGL Ex. 38.2, NS-PGL Ex. 28.3N, NS-PGL Ex. 38.3P, NS-PGL Ex. 38.4N, NS-PGL Ex. 38.4P; NS Ex. 9.0, NS Ex. 9.1 Public/Conf., PGL Ex. 9.0, PGL Ex. 9.1 Public/Conf.; NS-PGL Ex. 25.0; NS-PGL Ex. 43.0, NS-PGL Ex. 43.1, NS-PGL Ex. 43.2, NS-PGL Ex. 43.3 Affidavit; NS Ex. 11.0, NS Ex. 11.1, NS Ex. 11.2, PGL Ex. 11.0, PGL Ex. 11.1, PGL Ex. 11.2; NS-PGL Ex. 27.0, NS-PGL Ex. 27.1N, NS-PGL Ex. 27.1P, NS-PGL Ex. 27.2N, NS-PGL Ex. 27.2P, NS-PGL Ex. 27.3N, NS-PGL Ex. 27.3P, NS-PGL Ex. 27.4 Affidavit.

Commission Analysis and Conclusion

The Commission approves North Shore's and Peoples Gas' final revised operating expenses, which reflect adjustments proposed by Staff and GCI with which the Utilities agreed or accepted in whole or in part and certain updates. The Utilities are entitled to recover these proven costs through their rates. The detailed evidence in the record warrants this conclusion. The remaining contested adjustments proposed by Staff and GCI are erroneous, as discussed below.

B. Uncontested Issues

1. Physical Gas Losses

a. Modify Method of Accounting for Physical Gas Losses Associated with Manlove Field (PGL)

In rebuttal testimony, the Utilities accepted Staff's recommendation that Peoples Gas as of January 1, 2012, change its current method of accounting for physical gas losses to include its physical losses associated with Manlove in Account 823. Staff

Ex. 8.0 at 16-20; NS-PGL Ex. 33.0 Rev. at 6-7. Therefore, the Commission approves Staff's recommended modification to Peoples Gas' method of accounting for physical gas losses associated with Manlove Field.

b. Amend Written Procedures for Treatment of Physical Losses of Gas from Underground Storage Fields (PGL)

In rebuttal testimony, the Utilities accepted Staff's recommendations that Peoples Gas (1) collaborate with Staff to develop written procedures for the treatment of physical losses of gas from underground storage fields that are agreeable to both Peoples Gas and Staff, (2) amend its existing written procedures to account for the use of Account 823 for physical losses, (3) allow Staff to verify the remaining procedures comply with Commission rules, and (4) file its amended procedures on e-docket in this docketed proceeding within six months of the date of the Final Order. Staff Ex. 8.0 at 20-22; NS-PGL Ex. 33.0 Rev. at 7. Therefore, the Commission approves Staff's recommendations with respect to Peoples Gas' written procedures for the treatment of physical losses of gas from underground storage fields.

2. Distribution O&M

a. Expenses for locates, leak surveys, disconnects (O&M – PGL)

In rebuttal testimony, the Utilities' accepted GCI's proposed adjustment decreasing Peoples Gas' distribution operation and maintenance ("O&M") expenses related to locates, leak surveys, and disconnect expenses. GCI Ex. 2.0 Corr. at 18-19; NS-PGL Ex. 22.0 2 Corr. at 4-5. Therefore, the Commission approves GCI's adjustment.

b. Building Costs (PGL)

In rebuttal testimony, the Utilities accepted Staff's proposed adjustment decreasing O&M expenses related to Peoples Gas' leased property in Elwood, Illinois. Staff Ex. 8.0 at 4-5; NS-PGL Ex. 22.0 2 Corr. at 4-5. Therefore, the Commission approves Staff's adjustment.

3. Distribution O&M – Adjustment to Reflect Costs that Should Have Been Capitalized Instead of Expensed

In rebuttal testimony, Peoples Gas made corrections to its rate base and operating expenses for $829,000 of Distribution O&M expenses that should have been capitalized instead of expensed. NS-PGL Ex. 22.0 2 Corr. at 20–21. The corrections are uncontested. Therefore, the Commission approves Peoples Gas' corrected figures.

4. Distribution O&M - Inflation

GCI's rebuttal testimony accepted the Utilities' alternative adjustments for distribution O&M expenses inflation. GCI Ex. 7.0 at 10–11. Therefore, the Commission approves the Utilities' alternative adjustments.

5. Distribution O&M - Building Lease (PGL)

In their rebuttal testimony, the Utilities accepted Staff's adjustment relating to a building lease. NS-PGL Ex. 22.0 2 Corr. at 6. Therefore, the Commission approves Staff's adjustment.

6. Customer Service and Information

a. Advertising

Staff's rebuttal testimony withdrew the portion of Staff's advertising adjustments relating to customer satisfaction research. Staff Ex 11.0 at 3–4. Therefore, the Commission approves the Utilities' advertising expenses relating to customer satisfaction research as originally presented.

7. Administrative & General

a. Interest Expense on Budget Payment Plan

In their rebuttal testimony, the Utilities accepted Staff's adjustment relating to interest expense on budget payment plans. NS-PGL Ex. 22.0 2 Corr. at 5. Therefore, the Commission approves Staff's adjustment.

b. Interest Expense on Customer Deposits

In their rebuttal testimony, the Utilities accepted Staff's adjustment relating to interest expense on customer deposits. NS-PGL Ex. 22.0 2 Corr. at 5. Therefore, the Commission approves Staff's adjustment.

c. Lobbying

In their rebuttal testimony, the Utilities accepted Staff's adjustment relating to lobbying expense. NS-PGL Ex. 22.0 2 Corr. at 5. Therefore, the Commission approves Staff's adjustment.

d. Social and Service Club Dues

In their rebuttal testimony, the Utilities accepted Staff's adjustment relating to social and service club dues. NS-PGL Ex. 22.0 2 Corr. at 4. Therefore, the Commission approves Staff's adjustment.

e. Civic, Political, and Related

The Utilities at this time are not aware of an item to be discussed here.

f. ~~Charitable Contributions –~~ Reclassification of 2012 Costs

In their rebuttal testimony, the Utilities corrected the classification of certain 2012 test year data relating to Accounts 905 and 909, which does not relate to charitable contributions, and which has no net impact on their revenue requirements. NS-PGL Ex. 22.0 2 Corr. at 20. This was not contested. Therefore, the Commission approves the Utilities' reclassification of certain 2012 test year data relating to Accounts 905 and 909.

g. Inflation Factor Error-Miscellaneous Expense

In their rebuttal testimony, the Utilities accepted Staff's adjustment correcting an inflation factor error relating to miscellaneous expense. NS-PGL Ex. 22.0 2 Corr. at 4. Therefore, the Commission approves Staff's adjustment.

h. Employee Benefits – Adjustment to Test Year Pension and Benefits Expenses to Reflect Most Recent Actuarial Report

In their rebuttal testimony, the Utilities updated pension and OPEB expenses to reflect the most recent actuarial report (which reduced these expenses by an aggregate $21,473,000). NS-PGL Ex. 22.0 2 Corr. at 20–21. This was not contested. Therefore, the Commission approves the Utilities' adjustment to test year pension and OPEB expenses to reflect the most recent actuarial report.

i. Integrys Business Support Benefits Billed Expense

GCI withdrew its proposed adjustment related to IBS benefits expense. GCI Ex. 7.0 at 11. Therefore, the Commission approves the Utilities' IBS benefits expense as originally presented.

j. Advertising

In their rebuttal testimony, the Utilities accepted the portion of Staff's advertising adjustment not relating to customer satisfaction research. NS-PGL Ex. 22.0 2 Corr. at 7. Therefore, the Commission approves the portion of Staff's advertising adjustment not relating to customer satisfaction research.

8. Depreciation Expense on Utility Plant in Service – 2010 Actual

Staff's rebuttal testimony accepted the Utilities' revisions to Staff's adjustments to depreciation expense for 2010 actual plant in service. Staff Ex. 10.0 at 5–6. Therefore, the Commission approves Staff's adjustment as revised by the Utilities.

9. Current Income Taxes

a. Bonus Depreciation, Illinois State Income Taxes and Tax Accounting Method Changes

Other than derivative adjustments from uncontested issues associated with bonus depreciation deduction for federal income taxes and the increase in Illinois State Taxes and the contested tax accounting method changes, these figures were not disputed by any party. The Utilities' final amounts are shown in NS-PGL Ex. 39.2N and 39.2P Corr. The Commission finds the figures in NS-PGL Ex. 39.2N and 39.2P Corr. reasonable and appropriate subject to the derivative impacts of the Commission's rulings on the applicable adjustments discussed elsewhere in this Order.

b. Reclassification of Income Taxes on Charitable Contributions

In their rebuttal testimony, the Utilities corrected the classification of income taxes for charitable contributions in the 2012 test year data, which has no net impact on their revenue requirements. NS-PGL Ex. 22.0 2 Corr. at 18–19. This was not contested. Therefore, the Commission approves the Utilities' reclassification of income taxes for charitable contributions in the 2012 test year data.

10. Invested Capital Tax (derivative adjustments)

In rebuttal testimony, the Utilities accepted Staff's adjustments to operating expenses related to Invested Capital Taxes. Staff Ex. 1.0 at 16; NS-PGL Ex. 22.0 2 Corr. at 4-5. Therefore, the Commission approves Staff's adjustments.

11. Interest Synchronization (derivative adjustments)

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.

12. Updated Inflation Rate

In their surrebuttal testimony, the Utilities accepted Staff's adjustments for inflation, subject to corrected income tax calculations. NS-PGL Ex. 39.0 Corr. at 1. Therefore, the Commission approves Staff's adjustments for inflation, subject to corrected income tax calculations.

13. Rate 4 Revenues (NS)

In their rebuttal testimony, the Utilities corrected North Shore's base rate revenues under Rate 4. NS-PGL Ex. 22.0 at 22. This was not contested. Therefore, the Commission approves North Shore's corrected base rate revenues under Rate 4.

C. <u>Contested Issues</u>

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

North Shore and Peoples Gas

The Utilities presented uncontradicted evidence that 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 Watson, 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.,* NS Ex. 9.0 & PGL Ex. 9.0 at 2-4. The Utilities further explain that, even in today's economic environment, the Utilities' approach is prudent and reasonable, and that the alternative of moving more compensation to base pay would put them at a disadvantage in the labor market. *Id*. at 10.

The Utilities also offered specific evidence regarding their redesigned Non-executive Incentive Compensation Plan. *See* NS Ex. 9.0 & PGL Ex. 9.0 at 4-9; NS. Ex. 9.1 (Public/Conf.); PGL Ex. 9.1 (Public/Conf.) The Non-executive Incentive Compensation Plan provided for payouts based on the Utilities' performance against certain metrics. For both Utilities, there is a 50% weighting on a cost-control measure under which payout will occur if Non-fuel Operations & Maintenance ("O&M) Expense is kept at or below the target amount budgeted for the 2012 test year. NS Ex. 9.0 & PGL Ex. 9.0 at 5-6. This was a change from the metric in the Utilities' previous plan, which was based on meeting a net-income target the Commission held was not shown to be of primary benefit to customers, to a cost-side only metric that incentivizes employees to control and/or reduce operating costs, which is a metric that the Commission has found to be of direct benefit to customers. *Id*. at 8-9.

The other half of the Non-executive Incentive Compensation Plan is based on non-financial operation measures with the following weightings for the Utilities:

Non-Financial Operational Metric	Peoples Gas	North Shore
OSHA Recordable Incident Rates	15%	15%
Customer Satisfaction	15%	15%
System Reliability – Reduction of Leaks	10%	20%
System Reliability – Reduction in Damages from Third Parties as % of Locates	10%	n/a

NS Ex. 9.0 & PGL Ex. 9.0 at 6. The Utilities likewise chose these non-financial operational metrics to incentivize employees to achieve operational goals that the Commission has indicated in its previous orders that it would like to see achieved and/or that provide benefits to customers. *Id*. at 8-9.

Staff

[Insert]

GCI

[Insert]

North Shore and Peoples Gas Response

The Utilities oppose Staff's proposed disallowance of 50% of the Non-executive Incentive Compensation Plan's expenses related to its O&M cost-control metric and Staff's and GCI's proposed disallowance of a significant portion of the costs for the Executive Incentive Compensation Plan and 100% of the Omnibus Incentive Compensation Plan ("the Stock Plans"). The uncontradicted evidence establishes that the Utilities' incentive compensation expenses on the whole are reasonable and prudent operational costs for which they are entitled recovery as a matter of law. *CUB*, 166 Ill. 2d at 121, 651 N.E.2d at 1095 (1995); *Village of Milford v. Illinois Commerce Comm'n*, 20 Ill. 2d 556, 565, 170 N.E.2d 576, 581 (1960). *See* NS-PGL Init. Br. at 61-64.

The Utilities made challenges to the specific proposals of Staff and GCI, as well, in which they argue that each of the plans or portions thereof at issue provide benefits to customers so as to merit recovery under that legal standard urged by Staff and GCI.

Non-executive Incentive Compensation Plan

No party sought adjustment to the costs related to the non-financial operational metrics of the Utilities' Non-executive Incentive Compensation Plan, other than the O&M

expense control metric. Accordingly, the Commission should allow recovery of the uncontested costs.

Staff, but not GCI, however, proposed a disallowance of the costs related to the 50% metric of the Non-executive Incentive Compensation Plan's O&M expense control metric, based on three reasons: (1) it is a "financial" goal and thus non-recoverable; (2) the metric's target level for payout is based on the Utilities' 2012 test year budget; and (3) the metric is calculated on a combined utility basis that includes amounts for Integrys affiliates operating outside of Illinois. Ebrey Tr. 8/30/11 at 231-234; Staff Ex. 3.0 Corr. at 12-13. The Utilities argue that none of these reasons provides a supportable basis for disallowing incentive compensation costs and each should be denied.

With respect to Staff's first ground for its proposed disallowance, it is undisputed that the O&M expense metric is purely a cost-side item not at all based on revenues, for which payout will occur only if the Utilities keep the levels of their O&M costs at or below a certain level. NS-PGL Ex. 25.0 at 10; Ebrey Tr. 8/30/11 at 235. Thus, the O&M expense metric incentivizes employees to control or reduce expenses, which the Commission has consistently found to be a benefit to customers and, therefore, recoverable. The Utilities note that while Staff claims to base its proposal on past Commission orders, Staff conceded that the Commission specifically has approved recovery of costs related to O&M metrics, concluding that they benefit customers. Ebrey Tr. 8/30/11 at 213-214, 235-236.

Several of the Commission's previous orders found that a metric which incentivizes the control or reduction of O&M expenses is beneficial to customers and, therefore, recoverable. For example, in the Utilities' 2007 rate cases, the Commission allowed the Utilities to recover 48.4% of an incentive compensation plan's costs "based on controlling O&M expenses," stating that "we consider this as beneficial to ratepayers." *Peoples 2007*, pp. 66-67. Similarly, in ComEd's 2005 rate case, the Commission allowed the recovery of expenses for a component of ComEd's incentive compensation plan based on controlling O&M and capital expenses, stating that such a metric "meets the Commission's standard of reducing expenses and creating greater efficiencies in operations," and that "[l]owering O&M expenses, all else being equal, has the obvious effect of reducing the expenses to be recovered in future rate cases." *In re Commonwealth Edison Co.*, ICC Docket No. 05-0597 (Order July 26, 2006) ("*ComEd 2005*"), pp. 95-96. *Accord ComEd 2010*, pp. 60-65 (approving 100% recovery of an incentive compensation plan based, in part, on an O&M expense metric to which Staff had withdrawn all its proposed disallowances); *Commonwealth Edison Co.*, ICC Docket No. 07-0566 (Order Sept. 10, 2008) ("*ComEd 2007*"), pp. 54-55, 61 (approving recovery of costs for portions of incentive plan identical to those approved in *ComEd 2005*); *Consumers Illinois Water Company*, ICC Docket No. 03-0403 (Order Apr. 13, 2004), p. 15; *Aqua Illinois, Inc.*, ICC Docket No. 04-0442 (Order April 20, 2005), pp. 21-22.

Accordingly, the O&M expense metric is not a "financial goal" for which recovery is not allowed.

With respect to Staff's second ground for proposing the disallowance of costs related to the O&M expense control metric, Staff's position is unfounded because the target levels for payout under this metric are based upon the level of O&M expenses forecast in the Utilities' future 2012 test year budget submitted for these rate cases. By the very nature of a rate case using a future test year, a budgeted – *i.e.*, forecasted – target amount for O&M expenses must be used to set base rates because the future test-year has not yet occurred. NS-PGL Ex. 25.0 at 12. If the Utilities meet or beat this budgeted level of O&M expense, this will, all else being equal, reduce the expenses to be recovered in future rates cases, which is a direct benefit to customers. *See ComEd 2005*, p. 96.

At the hearing, Staff witness Ms. Ebrey stated that her concern was "not just limited to the test year in this case," but that in going forward "budgeted numbers may be overestimated" in the future in order to meet this metric. Ebrey Tr. 8/30/11 at 237. This is not a sound basis for a disallowance under the Commission's future test year rules and principles. The recovery to be set in these rate cases is based only on the levels of O&M expense forecasted for the 2012 test year and meeting that level is the metric for incentive compensation payout, <u>not</u> some speculative budget to be set in the future. Furthermore, as both Utilities and Staff agreed, the budgeted level of O&M expense at issue here for the 2012 test year has been subject to the full scrutiny of all the parties to this rate case proceeding, who could challenge that budgeted level if it were overestimated – but here, not one party did so. NS-PGL Ex. 25.0 at 12; Ebrey Tr. 8/30/11 at 238. Moreover, speculation that "budget numbers may be overestimated" in the future in order to meet this metric, without any evidence, is an improper basis for a Commission Order. *See, e.g., Ameropan Oil Corp. v. ICC*, 298 Ill. App. 3d 341, 348, 698 N.E.2d 582, 587 (1st Dist. 1998) ("speculation has no place in the ICC's decision"); *Allied Delivery System. Inc. v. Illinois Commerce Comm'n*, 93 Ill. App. 3d 656, 667, 417 N.E.2d 777, 785 (1st Dist. 1981) ("The speculation indulged in by the Commission is clearly an unsatisfactory and unacceptable basis for its decision.").

The Utilities also rely on previous Commission orders allowing recovery of costs for incentive compensation plans that measured performance against a budget. For example, in *Consumers Illinois Water Company*, ICC Docket No. 03-0403 (Order Apr. 13, 2004) ("*Consumers IWC*"), pp. 14-15, the Commission approved the recovery of Consumers Illinois Water Company's incentive compensation expenses which included a metric for "maintaining or reducing operating costs at or below <u>budgeted levels</u>." (emphasis added). *Accord ComEd 2005*, p. 96[2]; *ComEd 2007,* pp. 54-55, 61 (approving recovery of costs for portions of incentive plan identical to those approved in *ComEd 2005*); *ComEd 2010, pp.* 61, 65 (approving recovery of costs for incentive plan similar to those approved in *ComEd 2007* except for removal of net income metric);

[2] "While not expressly discussed by the Commission in its Order, the O&M metric it approved in this case was based on performance versus a budget, as explained in the testimony of ComEd's witness Richard F. Meischeid II (ComEd Ex. 12 at 13:284-287), available on the Commission's e-Docket system for ICC Docket No. 05-0597." NS-PGL Ex. 25.0 at 12, fn. 4.

Aqua Illinois, Inc., ICC Docket No. 04-0442 (Order April 20, 2005), pp. 21-22 (approving recovery of costs for incentive plan similar to the plan approved in *Consumers IWC*).

The Utilities further challenge Staff's reliance on the Commission's recent Order denying ComEd's request for approval of an alternative rate regulation plan pursuant to Section 9-244 of the Public Utilities Act, 220 ILCS 5/9-244, *In re Commonwealth Edison Co.*, ICC Docket No. 10-0527 (Order May 24, 2011) ("*ComEd Alt. Reg.*"). *See* Staff Ex. 3.0 Corr. at 13-14; Ebrey Tr. 8/30/11 at 237. The *ComEd Alt. Reg.* Order, the Utilities assert, is inapposite to the question of whether incentive compensation expenses are recoverable in a general rate case because here, the "budget" amounts at issue here are the 2012 test year numbers themselves, which have been subject to full scrutiny as part of these rate cases and will be used by the Commission as the basis for setting the Utilities' base rates going forward. NS-PGL Ex. 25.0 at 12. By contrast, the budget targets for the projects at issue in the ComEd alternative regulation proceeding were not being reviewed and vetted as part of a complete base rate case, and thus, the Commission was concerned that under those circumstances there was not "sufficient transparency to determine if the proposed budgets are reasonable." *ComEd Alt. Reg.*, p. 19. This concern about insufficient "transparency," the Utilities argue, does not exist here where the budgeted amount at issue is for O&M expenses that are normally and traditionally part of a utility's expenses reviewed in the course of a rate case and that amount is being subjected to the full scrutiny of a base rate proceeding. NS-PGL Ex. 25.0 at 13.

With respect to Staff's third ground for its proposed disallowance that the O&M metric measure includes the performance of the Utilities' non-Illinois affiliates (which supports only 44% of the disallowance as to Peoples Gas and 46% as to North Shore), the uncontradicted evidence establishes that the structure for the O&M expense metric reflects the Utilities' and Integrys' team-based philosophy that encourages Integrys' non-Illinois affiliates to share best practices with the Utilities. NS-PGL Ex. 25.0 at 5-6, 13. This creates benefits for Illinois customers, and because the Utilities share that corporate level of staff support, their share of the expense for that support should be recoverable. *Id*. at 6. The evidence demonstrated that Integrys' sharing best practices at a corporate level allows all of its affiliates, including the Utilities, to have access to high-quality, but expensive, resources and experts that the Utilities on their own would find it difficult to afford. *Id*. at 6, 13. The Utilities provided evidence of specific examples of such programs providing direct benefits to Illinois customers in terms of increased safety and improved customer satisfaction. *Id*. at 6; NS-PGL Ex. 43.0 at 4-5. The uncontradicted evidence in the record is that this allows Peoples Gas and North Shore to lower their O&M expenses, which results in direct benefits to Illinois customers. NS-PGL Ex. 25.0 at 13.

The Utilities urge the Commission to reject this third ground for Staff's proposed adjustment in its entirety, as well as the first two grounds. However, both the Utilities and Staff agree that if this third ground is the <u>only</u> basis upon which the Commission believes that costs related to the O&M expense metric should be disallowed, then the amount of that disallowance should be adjusted to reflect only the portion of those costs allocated to Integrys' non-Illinois affiliates. NS-PGL Ex. 25.0 at 13-14; NS-PGL Ex. 43.0 at 8-9; Ebrey Tr. 8/30/11 at 234-235. Under this scenario, Staff and Utilities agree that the apportionment of the costs for disallowance should be the same as Staff proposed for portions of the Executive Incentive Compensation Plan: 44% and 46% of the costs and rate base associated with the O&M expense metric for Peoples Gas and North Shore, respectively. NS-PGL Ex. 25.0 at 14; NS-PGL Ex. 43.0 at 9; Ebrey Tr. 8/30/11 at 235.

Executive Incentive Compensation Plan

Both Staff and GCI seek disallowances for portions of the Utilities' Executive Incentive Compensation Plan. The proposals can be divided into those addressing the Executive Incentive Plan's diluted Earnings Per Share ("EPS") metric and those related to the plan's operational metrics. Both sets of proposed adjustments lack merit.

With respect to the EPS metric, upon which 70% of this plan is based, both Staff and GCI seek the disallowance of the costs based on the EPS metric, alleging that it is a financial metric that does not incentivize customer benefits. *See*, *e.g.*, Staff Ex. 3.0 Corr. at 9; GCI Ex. 2.0 at 16. The Utilities challenge this conclusion. The actual record evidence demonstrates that the EPS metric can and does incentivize the Utilities' executives to reduce operating expenses, which the Commission has held to be of benefit to customers. Utilities witness Ms. Cleary testified that the EPS metric is derived from net income, which is dependent on both revenues and costs, so that executive employees have a significant incentive to reduce costs, which will result in a higher EPS. NS-PGL Ex. 25.0 at 5; NS-PGL Ex. 43.0 at 3. Indeed, both Staff and GCI witnesses agreed that, all else being equal, EPS will increase if a utility reduces its operating expenses. Ebrey Tr. 8/30/11 at 226; Effron Tr. 8/30/11 at 202. Thus, customers can benefit from their EPS increasing. *See* Effron Tr. 8/30/11 at 202.

Moreover, the Utilities provided a concrete example of how the EPS metric has worked to incentivize their executives to reduce expenses for purposes of increasing EPS, thereby benefiting customers. Ms. Cleary testified that the Utilities' top executives agreed to forego a general wage increase in 2009 in order to reduce costs and improve EPS, and that this one example alone resulted in a benefit to customers in the amount of $127,082. NS-PGL Ex. 25.0 at 5; NS-PGL Ex. 43.0 at 3-4. Therefore, the uncontradicted evidence proves that the Utilities' EPS metric <u>does</u> in fact benefit customers, so the costs associated with this metric should be recoverable.

With respect to the remaining 30% of the Executive Incentive Compensation Plan, which is based on three non-financial operational metrics (employee safety, customer satisfaction and environmental impact reductions), Staff (but not GCI) seeks additional adjustments. Staff's proposed adjustment is based on the fact that these operational metrics consider the achievements of all the Integrys utilities, including non-Illinois affiliates of the Utilities. Staff Ex. 3.0 Corr. at 10-11. Staff proposes disallowance of the portion of those costs allocated to the Utilities' non-Illinois affiliates

(44% for Peoples Gas and 46% for North Shore). *Id*. at 10 and Scheds. 3.2 P and 3.2 N.

The Utilities challenge Staff's proposed adjustment on grounds that Integrys and the Utilities operate on and share a team-based philosophy, whereby Integrys, at the corporate level, operates programs that allow each of its affiliates, including Peoples Gas and North Shore, access to experts and industry-wide best practices programs that each affiliate unlikely would be able to afford on its own. NS-PGL Ex. 25.0 at 5-6. In her testimony, Ms. Cleary gave specific examples of such programs related to each of the Executive Incentive Compensation Plan's non-financial operational metrics and explained how they directly benefit customers <u>in Illinois</u>:

- A benchmark safety program giving Peoples Gas and North Shore access to a specialized team of experts that has led to Peoples Gas and North Shore reducing their OSHA recordable rates from 10.43 to 3.34 and 11.31 to 2.59 between 2010 and the first quarter of 2011, respectively, *Id*. at 6; NS-PGL Ex. 43.0 at 4-5;

- Access to J.D. Powers methodologies for improving customer service, NS-PGL Ex. 25.0 at 7; NS-PGL Ex. 43.0 at 5; and

- Access to a team of environmental experts for Peoples Gas and North Shore to consult on reducing greenhouse gas emissions. NS-PGL Ex. 25.0 at 7; NS-PGL Ex. 43.0 at 5.

Ms. Cleary's uncontradicted testimony is that these programs allow Peoples Gas and North Shore to provide benefits to their customers in Illinois. NS-PGL Ex. 25.0 at 7; NS-PGL Ex. 43.0 at 5. Based on that testimony, the Utilities argue that the costs for the incentive compensation metrics related to these programs that incentivize the Utilities' executives to generate those benefits for Illinois customers should be recoverable.

The Utilities also challenge Staff's additional proposal to further reduce the costs related to these operational metrics by 50% because the Executive Incentive Compensation Plan provides that payouts for these metrics will be reduced by 50% if the EPS threshold is not met. Staff Ex. 3.0 Corr. at 11. Contrary to Staff's assertion, this does not call the accuracy of the forecasted costs for these metrics into question. The Utilities presented uncontradicted evidence demonstrating that since its formation in 2007, Integrys has consistently met its EPS targets disclosed to and relied upon by the financial community. NS-PGL Ex. 25.0 at 8. Furthermore, the Utilities rely upon the same arguments raised against Staff's proposal with respect to the 70% EPS metric discussed above.

The Utilities should be allowed to recover all their expenses related to the Executive Incentive Compensation Plan.

Omnibus Incentive Compensation Plan (Stock Plans)

Both Staff and GCI propose disallowing all of the Utilities' costs for the Stock Plans alleging they are based on financial measures that primarily benefit shareholders and not customers. Staff Ex. 3.0 Corr. at 15-16; GCI Ex. 2.0 at 16. Staff's and GCI's proposal ignores the uncontradicted testimony of Ms. Cleary that, absent the Stock Plans, the Utilities' compensation package could not be competitive with the other energy and non-energy companies with which they compete for employees that offer compensation packages which include stock plans in addition to base pay and incentive pay. NS-PGL Ex. 25.0 at 16-17. The Utilities also presented uncontradicted evidence that the Stock Plans help the Utilities maintain a steady and experienced executive team that leads to the Utilities' efficient and successful operation, which inures to the benefit of customers. *Id*. at 17. The costs of the Stock Plans are reasonable and prudent costs, and that the Commission should deny this proposed disallowance.

Commission Analysis and Conclusions

The Utilities presented uncontested evidence that their total compensation levels and the designs of their incentive compensation plans are prudent and reasonable from an operational perspective, help attract and retain a sufficient and qualified workforce, and help reduce recruiting and retention costs. While the Utilities present evidence supported by an expert in human resources, neither the Staff witness nor the AG-CUB witness is an expert on human resources. Although the Commission continues to find the benefits to customers of attracting and retaining such a work force to be a very general benefit to customers, it cannot be denied that it is a benefit given the evidence in the record. Moreover, it is a settled general principle that employee salaries are operating expenses and, as such, are recoverable in full by the Utilities so long as they are prudent and reasonable – which no party here has challenged. *See, e.g., Milford*, 20 Ill. 2d at 565, 170 N.E.2d at 581.

<u>Non-executive Incentive Compensation Plan</u>

Turning to the Non-executive Incentive Compensation Plan, no party has challenged the Utilities' recovery of the costs related to that plan's non-financial operational metrics other than the O&M expense control metric. Thus, the Commission approves the recovery of those expenses by the Utilities.

With respect to the Staff's proposed disallowance of costs related to the Non-executive Incentive Compensation Plan's 50% O&M expense cost control metric, the Commission finds that the first two grounds Staff relies upon are unfounded. First, consistent with our decisions in several past Orders, we confirm that any metric that encourages a utility to control or reduce operating costs – including O&M costs – is one that benefits customers. Staff's focus on whether a metric is "financial" is misplaced. The question with which we are concerned is not whether a metric is "financial," but rather, whose finances that metric seeks to improve: those of the customers or those of the shareholders. The Utilities' O&M metric here focuses only on operating costs. All else being equal, the control or reduction in such costs will have the obvious effect of reducing expenses to be recovered in future rate cases, and that benefits customers. This decision is consistent with our rulings in the Utilities' previous rate cases and in the rate cases of other utilities. *See*, *e.g.*, *Peoples 2007*, pp. 66-67; *ComEd 2005*, pp. 95-96.

Second, the Commission agrees with the Utilities that Staff's attempt to rely upon our Order in the ComEd alternative regulation proceeding is misplaced. The use of a target based on the budget forecast used in a utility's future test year rate case does not raise the same "transparency" problems with which we were concerned in our *ComEd Alt. Reg*. Order. While we would share Staff's concerns with a utility that attempted to inflate a budget target in order to ensure payout of incentive compensation, the budget target at issue here was subject to the full scrutiny of all the parties to these rate cases, and no evidence was presented of any inflation or overestimation of the O&M budget by the Utilities here related to their incentive compensation plans. The Commission, therefore, denies this ground for Staff's proposed adjustment as well. Again, our decision here is consistent with our prior Orders. *See*, *e.g.*, *Consumers IWC*, pp. 14-15; *ComEd 2005*, p. 96.

This leaves Staff's third ground for its proposed disallowance of the costs related to the O&M metric: the inclusion of non-Illinois affiliates' performance. **[Alternative #1 – No disallowance on this basis]** While we have disallowed incentive compensation costs of the Utilities in their previous rate cases on this basis, the Commission believes that the evidentiary record here merits a different result. In this case, the Utilities presented specific evidence with concrete examples of how Integrys' team-based philosophy of sharing best practices across its affiliates at the corporate level specifically provides benefits to customers <u>in Illinois</u> that are related to the O&M metric at issue. Ms. Cleary testified that in exchange for sharing the corporate expenses for such programs, Peoples Gas and North Shore had access to experts that have helped it lower O&M expenses. Based on this evidence, which was uncontradicted, we draw the conclusion that the Utilities have met their burden of proving that the shared corporate costs for these programs related to its incentive plan O&M metric lead to benefits for Illinois customers. Thus, we reject this ground for Staff's proposed disallowance as well, and the Commission concludes that all of the costs related to the O&M metric of the Utilities Non-executive Incentive Compensation Plan are approved for recovery. Accordingly, all of the Utilities' costs for this incentive compensation plan ($4,389,000 in operating expense and $982,000 in rate base for Peoples Gas and $831,000 in operating expense and $171,000 in rate base for North Shore), and any items derivative of these costs, are recoverable.

[Alternative #2 – Disallowance of costs related to non-Illinois affiliates] While we acknowledge the Utilities' evidence concerning the sharing of best practices and access to programs by the Utilities that may be of benefit to their Illinois customers, we do not believe that the Utilities have meet their burden and decide that the proportion of the costs for the O&M metric allocated to Integrys' non-Illinois affiliates should be disallowed. The amount of this adjustment to the recoverable costs related to the Non-executive Incentive Compensation Plan's O&M metric shall be based upon the allocation agreed to by both the Utilities and Staff: 44% for Peoples Gas and 46% for North Shore. Accordingly, $966,000 in operating expenses and $216,040 in rate base for Peoples Gas and $191,000 in operating expenses and $39.560 in rate base for North Shore are disallowed from the costs of their Non-executive Incentive Compensation Plan, with similarly proportioned adjustments to any items derivative of these costs. The remaining costs for this incentive compensation plan ($3,423,000 in operating expense and $765,960 in rate base for Peoples Gas and $640,000 in operating expense and $131,440 in rate base for North Shore) are approved for recovery.

Executive Incentive Compensation Plan

Turning to the Utilities' Executive Incentive Compensation Plan, the Commission agrees with the Utilities that in this case, specific evidence has been presented to establish that the EPS metric does, in fact, incentivize the Utilities' executives to reduce costs, which results in a benefit to customers. All parties – Utilities, Staff and GCI – agree that all else being equal, EPS will increase if the Utilities' costs are reduced, such that an increasing EPS may result in customer benefits. In addition to this general principle, the Utilities presented specific evidence proving that this hypothetical principle leads to real-world reaction to the benefit of customers. Ms. Cleary's testimony demonstrated that this metric incentivized the Utilities' executives to forego a wage increase that resulted in a benefit to customers in the amount of $127,082. Accordingly, based on this evidence particular to the Utilities, the Commission approves the recovery of 70% of the Executive Incentive Compensation Plan's costs related the EPS metric. Moreover, for the same reasons, the Commission declines to adopt Staff's additional proposed 50% adjustment to the costs related to the remaining non-financial operational measures based on the plan's 50% reduction of payout for those metrics if the EPS threshold is not met.

As for Staff's further proposed disallowance of costs for the non-financial operational metrics based on the inclusion of non-Illinois affiliates' performance, again, the Commission finds, on the basis of the record in these cases, that the Utilities have established that the portion of these costs allocated to the corporate level do lead to Illinois customers receiving benefits. The Utilities provided concrete and specific evidence of how this sharing of best practices by all affiliates at Integrys' corporate level allow the Utilities to gain access to resources they likely would not otherwise have. And, the evidence demonstrates that these resources provide benefits to Illinois customers directly related to each of the plan's non-financial operational goals – reduction of OSHA recordable rates, customer satisfaction and reductions in greenhouse gas emissions. The Commission thus approves the recovery of the entire amount of the costs related to these non-financial operation metrics of the Executive Incentive Compensation Plan.

Accordingly, all of the Utilities' costs for this incentive compensation plan ($1,364,000 in operating expense for Peoples Gas and $210,000 in operating expense for North Shore), and any items derivative of these costs, are recoverable.

Omnibus Incentive Compensation Plan

Finally, the Commission agrees with the Utilities that they have presented sufficient evidence to establish that their incentive Stock Plans provide benefits to customers in terms of ensuring a steady and experienced executive team at the Utilities, which increases efficiency and leads to a more successful operation. The Commission, therefore, denies the disallowances proposed by Staff and GCI and approves recovery of the costs for the Utilities' Omnibus Incentive Compensation Plan ($3,129,000 in operating expense for Peoples Gas and $544,000 in operating expense for North Shore), and any items derivative of these costs .

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

Staff

[Insert]

North Shore and Peoples Gas Response

The Utilities challenge Staff's two-step proposal to decrease Peoples Gas' and North Shore's non-union base wages.

Staff's first step – removing the .3% and .6% discrete pools of funds used to provide merit increases and salary increases corresponding to promotions, respectively in 2011 and forecasted for 2012 – is not supported by the record. The basis for Staff's proposal to remove these increases is that while the general wage increase of 3.0% was supported by the most current World at Work Survey, only the "highest performers" could expect as high as a 4.0% increase. Staff Ex. 12.0 Corr. at 14-15. This reasoning ignores the fact that these funds are being used to provide raises to the Utilities' highest performers – those deserving of merit-based wage increases and/or promotions. NS-PGL Ex. 43.0 at 11. The pool of funds that, in total, equals .3% of the previous year's level of wages is used to give discrete performance raises to certain top-performing non-union employees with commendable or exemplary performance. NS-PGL Ex. 25.0 at 20. This was not, as assumed by Staff, an across the board increase to all employees elevating all of them to a "top-performer" status; rather, only certain top-performers received merit raises which, in the aggregate, total .3% of the overall wage base.

Moreover, with respect to the pool of funds equal to .6% of the overall wage base, Staff's analysis of this amount based upon the World at Work Surveys or consumer inflation predictions is inapposite. That is because this amount does not represent general inflationary wage increases, but rather, salary increases that correspond to the promotions of certain employees, *i.e.,* changes in certain employees' relative positions within the Utilities based on the going market based rate of pay for their new elevated positions. NS-PGL Ex. 43.0 at 11-12. Further, the Utilities presented evidence that these are promotions that had been put on hold since a freeze on promotions was put in place in 2008, and the Utilities would be in danger of losing these trained and experienced employees unless they are recognized for the promotions they are due. NS-PGL Ex. 25.0 at 21.

Staff's second step is then to reduce further the wage increase forecast for 2012 by adjusting the general wage increase in that year downward from 3.0% to 2.30% based upon a level of the Consumer Price Index ("CPI") forecast for the 2011-2015 period. Staff Ex. 12.0 Corr. at 15-17. The Utilities argue that Staff's proposal is wrong for ignoring the World at Work Salary Budget Survey results for 2012 in favor of the CPI forecast. The Utilities demonstrated that the World at Work Salary Budget Survey is a well-known compensation tool that is based on information submitted by corporations in all industries for the specific purpose of assisting in corporate salary budget planning, and that the results of this survey are tied directly to the market and support the Utilities' compensation philosophy of paying at the market median. NS-PGL Ex. 25.0 at 19. The Utilities further rely upon the fact that the survey is forward looking and specifically designed to address the question of what level of general wage increases are forecast for 2012, the test year in this case. The 2.9% level projected for 2012 by the World at Work Survey is right in line with and supports the Utilities' projected 3.0% general increase in the level of non-union wage base in the 2012 test year.

The Utilities also critique Staff for relying on CPI in this context, arguing that CPI is not a measure designed to calculate changes in wages, but rather, an economic indicator calculated by the Bureau of Labor Statistics to show a change over time in the prices paid by consumers for a market basket of goods and services. *Id*. at 19. Utilities' witness Ms. Cleary testified: "[CPI] is a measure that reflects spending patterns of consumers, not the wage setting decisions of employers." *Id*. at 19-20. Ms. Cleary further testified that the Bureau of Labor Statistics calculates and publishes a completely different measure specifically designed to measure changes in wages and salaries by industry – the Employment Cost Index – which has shown that wages in the utility industry have been increasing at a faster pace than overall wages generally. *Id*. at 20; NS-PGL Ex. 43.0 at 12-13 and fn. 4. The Utilities further argue that Staff's reliance on the 2011-2015 CPI forecast was improper for speculating how long rates will be in effect and looking outside the 12-month future test year period. NS-PGL Ex. 43.0 at 13.

Commission Analysis and Conclusions

The Commission concludes that Staff's proposal to remove the .3% and .6% pools of funds used for providing merit increases and salary increases corresponding to promotions is erroneous and unreasonable. The Utilities' evidence demonstrated that these funds were used to award only those "high performer" employees that Staff's own testimony indicated could expect wage increases of up to 4%, not an across the board increase for all employees. Moreover, Staff's proposal fails to recognize that the .6% pool of funds identified by the Utilities was not truly a wage increase, per se, but an increase in costs related to employees changing positions so that their base wage levels would be higher relative to their former positions, based on the market rate of pay for those new positions. The Commission acknowledges that the granting of promotions by the Utilities is a reasonable and prudent action taken to ensure the retention of its most experienced and highest-performing employees.

The Commission likewise concludes, based on the evidence presented by the Utilities, that Staff's reliance on a five-year forecast of CPI was misplaced in this context. We agree with the Utilities that CPI is not an appropriate measure to use for forecasting general wage increases instead of the World at Work Survey which is both specifically designed to answer that question with particularity for the test year period at issue. Moreover, Staff's reliance on forecasts beyond the 2012 is not appropriate in the context of a future test year rate case.

Accordingly, the Commission approves the levels of non-union wage base increases submitted by the Utilities in these rate cases, and denies the adjustments proposed by Staff to these figures.

3. Headcounts (Falls in Multiple Categories of O&M)

GCI

[Insert]

North Shore and Peoples Gas Response

Mr. Effron's bare opinion, without more, cannot overcome Peoples Gas' testimony indicating that it would be hiring more employees. NS-PGL Ex. 24.0 at 5–6. Utilities witness Mr. Doerk testified that Peoples Gas had specific plans to bring on new employees. NS-PGL Ex. 24.0 at 5–6. In fact, Peoples Gas is currently filling 30 temporary Operations Apprentice positions to complete an ever expanding workload. Even though these hires are intended to be on the payroll for 18 months, alternative resources will be deployed to fulfill the compliance inspections, including prospective Utility Workers to be hired from a proposed company designated trade school. *Id*. By the time Mr. Doerk filed surrebuttal testimony, 20 of these positions had been filled and the remaining 10 positions were to be filled within weeks. NS-PGL Ex. 41.0 at 2. These employees being hired are necessary for the direct execution of compliance work. *Id.* Furthermore, over 2011 and 2012, due to normal attrition and increased resources required for AMRP, Peoples Gas will be continually hiring more people to maintain the budgeted head count. *Id.*

Commission Analysis and Conclusion

The Commission finds that the evidentiary record does not support GCI's proposed headcount adjustment for Peoples Gas. Peoples Gas has submitted evidence proving that its forecast of 1,120 employees for the 2012 test year is realistic. Therefore, the Commission rejects GCI's proposed decrease in headcount.

4. Self-Constructed Property

GCI

[Insert]

North Shore and Peoples Gas Response

The prudence and reasonableness of these costs is not challenged. These costs belong either in operating expenses or rate base. NS-PGL Ex. 38.0 at 5. The Utilities state that GCI cannot have it both ways by removing the costs of self-constructed property from Peoples Gas' operating expenses and not proposing to add all or any of these costs to Peoples Gas' rate base.

GCI showed through testimony and cross-examination of Staff's and the Utilities' witnesses on this subject that the Uniform System of Accounts permits the costs in question to be capitalized, but GCI did not prove that the only proper treatment is capitalization and not expensing. The Utilities' and Staff's witnesses each submitted written testimony indicating that either treatment is proper. NS-PGL Ex. 21.0 Corr. at 12; NS-PGL Ex. 11.0 at 10–11; NS-PGL Ex. 38.0 at 4–5. The AG cross-examined Staff's and the Utilities' witness on this point, using an excerpt from the Uniform System of Accounts that had not been quoted or cited in GCI's witness' written testimony (AG Cross. Ex. 13). Staff's witness restated his agreement with the Utilities before reading language from the document, but he was not asked if it changed his opinion. Ostrander Tr. 8/30/11 at 284–287. The Utilities' witness also acknowledged the language of the document but she was not asked if it changed her opinion. Gregor Tr. 9/2/11 at 922-925. The document (p. 11) includes the phrase "shall include", but that is immediately followed by "where applicable", and neither the document itself (apparently) nor any cross-examination indicated the meaning of the latter qualifying language. Also, the document (p. 12) says "'General administration capitalized' includes the portion of the pay and expenses of the general office and administrative and general expenses applicable to construction work", but nowhere did GCI define what this means and the costs the Utilities are currently capitalizing are far removed from the actual construction work, as indicated by the testimony cited above.

Finally, Peoples Gas notes that if GCI's adjustment were to be adopted, which it should not be, then the costs in question must be added to Peoples Gas' rate base.

Commission Analysis and Conclusion

The Commission finds that the prudence and reasonableness of Peoples Gas' costs of self-constructed property is not challenged by GCI and that the Uniform System of Accounts permits the costs in question to be expensed as Peoples Gas has done. Therefore, the Commission rejects GCI's adjustment.

5. Uncollectibles Expense – Use of Net Write-Off Method

Staff

[Insert]

North Shore and Peoples Gas Response

Staff's proposal would result in a $510,000 increase in the uncollectibles expense in Peoples Gas' revenue requirement and a $421,000 decrease as to North Shore. Staff Ex. 1.0, Scheds. 1.11N and 1.11P; NS-PGL Ex. 21.0 Corr. at 8–9. Staff's proposal is very problematic and should not be adopted, for three reasons discussed here. The Utilities further note an additional problem with Staff's proposal in that Staff has not adequately addressed the necessary changes to the tariff language required by its proposal. *See* Section VIII.A, *infra*.

First, if the Utilities were to switch to the net write-off method, then there would be no reliable method to determine how much of the actual write-offs are related to the Gas Charge as opposed to delivery rates, and that information would be needed to remove the gas cost related amount from the revenue requirement and for the Rider UEA-GC filing. Customer accounts are written off in total, they can include receivables from multiple periods, and the ratio of Gas Charges and delivery rates in customers' bills will vary between periods. The net write-off method would have unpredictable results and would lead to inaccurate reconciliations. In contrast, the Utilities' percentage of revenues method allows a more consistent comparison of Gas Charge revenues, gas-cost related uncollectibles expense, and ICC Form 21 data and is superior. The amount of Gas Charge revenues in any given actual or forecasted year is a known amount. Therefore, it is a simple calculation to multiply the Gas Charge revenues by the approved percentage for bad debt to determine the bad debt related to the Gas Charge. NS-PGL Ex. 21.0 Corr. at 8; NS-PGL Ex. 28.0 at 38–39; NS-PGL Ex. 38.0 at 5–6.

Second, the net write-off methods would lead to a mismatch between revenues and the uncollectibles expense being recorded. While some degree of timing differences may be inherent in tracking riders, the net write-off method would cause much greater lags because the lag between the ultimate reconciliation of expense to the related revenue could lead, for example, to customers paying for high levels of write-offs related to years before they even were customers of the Utilities. NS-PGL Ex. 21.0 Corr. at 8.

Finally, if the net write-off method were to be employed, then Staff's proposal is seriously flawed by using data from a single year. A six year average would be the minimum reasonable period for that method, because of the great variability in write-offs resulting from changing gas prices and the economy. However, this would not solve the problem of allocating the write-offs between Gas Charge and delivery rates. NS-PGL Ex. 21.0 Corr. at 8–9; NS-PGL Ex. 38.0 at 6.

Commission Analysis and Conclusion

The Commission finds that the Utilities have demonstrated that their approach is reasonable and appropriate and that there are several practical problems inherent in Staff's proposal that Staff has not resolved as well as no demonstrated advantage of Staff's proposal. Therefore, the Commission rejects Staff's proposal.

6. <u>Administrative & General</u>

a. <u>Injuries and Damages Expenses</u>

GCI

[Insert]

North Shore and Peoples Gas Response

GCI's proposal is erroneous because it is based on incorrect interpretation of a data request response and extrapolation based largely on a single year (2010) in which the level of Peoples Gas' injuries and damage expenses was unusually low. NS-PGL Ex. 21.0 Corr. at 11; NS-PGL Ex. 38.0 at 3–4.

Peoples Gas, in its surrebuttal, reduced the amount in its revenue requirement for injuries and damages expense by $1,433,000 to $12,142,000, based on the most up to date forecast for the 2012 test year. NS-PGL Ex. 38.0 at 3–4. No further reduction is warranted and GCI has provided no basis for rejecting the updated test year value.

Moreover, Peoples Gas' revised figure of $12,142,000 is very close to both: (1) the 2009-2011 actuals and 2011 updated forecast combined three year average (mean) of $11,817,667 and (2) the 2009-2010 actuals and 2011-2012 updated forecasts combined four year average (mean) of $11,898,750, in each instance even before correcting the 2009-2011 figures for inflation. The 2009 actual amount was $12,913,000 (PGL Ex. 5.1, p. 4, line 28, col. (F). The 2010 actual amount was $8,684,000. NS-PGL Ex. 38.0 at 3. The updated forecasts for 2011 and 2012 are $13,856,000 and $12,142,000 respectively. *Id* at 4.

In contrast, GCI's proposal would set the level for this item at $10,498,000, far below that average. *See* GCI Ex. 7.0 at 14. GCI's proposal is an outlier compared with the updated 2012 test year estimate and the averages.

In the 2007 rate cases, the Commission approved use of the Utilities' historical test year injuries and damage expense levels, with one adjustment by Peoples Gas for an unusual item in the test year, rejecting a Staff-proposed downward adjustment based on a complicated multi-year average where slightly changing which years were used produced large differences. *Peoples 2007*, p. 57.

In the 2009 rate cases, the Commission approved use of the Utilities' forecasted test year injuries and damage expense levels, again rejecting a Staff-proposed downward adjustment based on a multi-year average. *Peoples 2009*, pp. 84-85.

Commission Analysis and Conclusion

The Commission has previously addressed similar issues in the Utilities' 2007 and 2009 rate cases. In those prior cases, the Commission rejected similar proposals from Staff to supplant the test year value. The Utilities have demonstrated the outlier nature of the GCI proposal compared with the updated 2012 test year estimate and the averages. Further, GCI has provided no valid justification for adopting its proposal over that of the Utilities, which is an updated, already reduced figure. Therefore, the Commission rejects GCI's proposed adjustment.

b. <u>Adjustment to Account 921 - Office Supplies and Expenses</u>

The only contested issue with respect to Account 921 is addressed in Section V.C.4.

The only other proposed adjustment to these expenses (which related to cellular costs) was made, but later was withdrawn, by GCI. NS-PGL Ex. 21.0 Corr. at 12; GCI Ex. 7.0 at 13.

c. <u>Rate Case Expenses</u>

(i) <u>Rate Case Expenses – Docket Nos. 11-0280/0281 (cons)</u>

North Shore and Peoples Gas

The Utilities showed that their revised proposed rate cases expenses are just and reasonable, and the evidentiary record contains more than sufficient information for the Commission to so find consistent with Section 9-229 of the Act, 220 ILCS 5/9-229. The Utilities, in planning and budgeting for the preparation and prosecution of these cases, sought to incur only prudent and reasonable rate case expenses. Factors identified in managing and estimating these costs included: (1) efficiencies resulting from simultaneous preparation and anticipated consolidation of Peoples Gas' and North Shore's rate case filings; (2) selection of outside counsel and expert resources with extensive experience in Illinois rate cases and other proceedings and negotiations of appropriate estimated hours of work and rates; (3) cost effective use of IBS to provide rate case support services; and (4) the extensive procedures involved in prosecuting a rate case after filing which include: the discovery process, analysis of Staff and intervenor direct and rebuttal testimonies, assistance with preparation of rebuttal and surrebuttal testimonies, the evidentiary hearing, post-hearing briefs and reply briefs, analysis of the Administrative Law Judges' Proposed Order, briefs and reply briefs on exceptions, preparation and participation in oral argument, analysis of the final Commission Order, and preparation of a compliance filing. The amounts originally estimated reflected prudent and reasonable budgets for the work of the outside consultants, the outside legal counsel, and applicable IBS personnel on the preparation and prosecution of these rate cases. These expenses were the subject of voluminous ongoing discovery, and they were updated and reduced by Staff in rebuttal (including supplemental rebuttal) and then by the Utilities in surrebuttal. NS Ex. 6.0 at 16-17; NS Ex. 6.2; PGL Ex. 6.0 at 16-17; PGL Ex. 6.2; NS-PGL Ex. 22.0 2 Corr. at 9-16; Staff Ex. 11.0 Corr. at 4–7 and Scheds. 11.1N, 11.1P Corr.; Staff Ex. 20.0 at 2–3 and Scheds. 201.N, 20.1P; NS-PGL Ex. 39.0 at 7–10; NS-PGL Exs. 30.4N, 39.4P, 39.9N (Public/Conf.), 39.9P (Public/Conf.).

Other Parties

[Insert]

North Shore and Peoples Gas Response

Staff's Proposed Adjustments. There is no dispute between Staff and the Utilities regarding the rate cases expenses of the instance cases, with one limited exception. Staff presented proposed adjustments based on updating in its rebuttal, and the Utilities accepted those adjustments, with some further updating that further slightly reduced the expenses, in their surrebuttal. Staff Ex. 20.0 at 2–3 and Scheds. 20.1N, 20.1P; NS-PGL Ex. 39.0 at 7–10; NS-PGL Exs. 39.4N, 39.4P.

The sole open item with respect to Staff's position is that Staff also proposed to disallow $39,000 as to North Shore and $54,000 as to Peoples Gas that reflected incentive compensation amounts relating to the Non-Executive Incentive Compensation program included in the amounts relating to IBS personnel. Staff Ex. 20.0 at 2–3 and Scheds. 20.1N, p. 2, line 9, col. (g), and Sched. 20.1P, p. 2, line 9, col. (g). To simplify the issues, the Utilities agreed that, to the extent the Commission agrees with Staff's proposed disallowances relating to the Non-executive Incentive Compensation program, discussed in Section V.C.1, then to the same extent the aggregate $93,000 at issue here should be removed. The Commission's conclusion with respect to this issue is addressed in Section V.C.1, *supra*.

GCI's Proposed Adjustments. GCI's witness proposed no adjustment to any particular rate case expenses. GCI's witness, Mr. Morgan, in his direct testimony, indicated that he needed additional information on the subject, noting some particular areas where he had potential concerns but not proposing any adjustments, but, as the Utilities understand his rebuttal testimony, he was satisfied by the information he later received. GCI Ex. 1.0 at 21; GCI Ex. 6.0 at 5.

Instead, GCI's witness, for the first time in his rebuttal, proposed a "50/50 sharing" of rate case expenses between the Utilities and customers, *i.e.,* to disallow 50% of the expenses. GCI Ex. 6.0 at 7. He offers two grounds: (1) rate increases benefit shareholders and (2) sharing provides an incentive for controlling rate case expenses. *Id*. Mr. Morgan's proposal is inappropriate, for several reasons.

First, rate case expenses are a cost of doing business that the Utilities are entitled to recover. The Utilities have a legal right to rates that allow them the opportunity to recover fully their prudent and reasonable costs of service, and rates are required to be just and reasonable for the Utilities and their shareholders as well as customers. Customers do not have a right to rates set below the utility's cost of service. The reality, however, is that the Utilities have not been recovering fully their costs of services, as shown by the rate increases approved in the 2009 rate cases and by the facts that even after those rate increases the Utilities still have recovered less than their approved ROEs and they face much worse cost recovery shortfalls in the 2012 test year, all of which means the filing of these rate cases was appropriate and consistent with the Illinois ratemaking process. *Peoples 2009*, pp. 273-276; NS-PGL Ex. 39.0 Corr. at 14; NS Ex. 1.0 at 4; PGL Ex. 1.0 at 4. Rate cases filed by a utility are the primary means by which rates are revised to meet with the above legal requirements. While the timing of rate cases is intermittent and unpredictable, when they occur they are a normal cost of doing business for a utility. NS-PGL Ex. 39.0 Corr. at 11. The Illinois Supreme Court has rejected requiring a utility to "share" reasonable amounts incurred in light of legal requirements. *CUB*, 166 Ill. 2d 111, 121, 651 N.E.2d 1089, 1095 (1995) (reversing Commission Order directing the sharing of costs incurred by utilities under environmental laws).

Second, the Utilities have ample incentives to control rate case expenses, such as the fact that they bear in the first instance but recover no carrying costs on these expenses, and the uncontradicted evidence shows they did manage these expenses in these cases, as discussed above and as reflected in the decrease from the levels proposed and allowed in their 2009 rate cases that GCI's witness himself noted. NS-PGL Ex. 39.0 Corr. at 10, 11; *see* GCI Ex. 1.0 at 16.

Finally, Section 9-229 does not alter the foregoing legal and factual points. (Nor does the GCI witness claim that Section 9-229 supports his belated proposal.) Section 9-229 does not provide for or support any "sharing" of rate case expenses. The Commission rejected GCI's proposal for a 50/50 sharing of charitable contributions in ComEd's 2010 rate case as contrary to Section 9-227 of the Act, 220 ILCS 5/9-227. *ComEd 2010* at 109. While Sections 9-227 and 9-229 differ in various respects, they each relate to recovery of a particular kind of expense, and neither provides for any "sharing" of that expense. Indeed, the Utilities' rate cases expenses in their 2009 rate cases were found just and reasonable, with the Commission referencing Section 9-229. *Peoples 2009*, p. 43. The Commission also has approved rate case expenses in numerous cases, including at least ten other rate cases in which it has approved rate case expenses and referenced Section 9-229. *MidAmerican Energy Co.*, ICC Docket No. 09-0312 (Order Mar. 24, 2010), p. 43; *Illinois-American Water Co.*, ICC Docket No. 09-0319 (Order Apr. 13, 2010), p. 80; *Central Illinois Light Co., et al.*, ICC Docket Nos. 09-0306 Cons. (Order Apr. 29, 2010), p. 70; *Apple Canyon Utility Co., et al.*, ICC Docket Nos. 09-0548 (Order Sept. 9, 2010) , pp. 20-21; *Consumers Gas Co.*, ICC Docket No. 10-0276 (Order Oct. 6, 2010), p. 4; *Whispering Hills Water Co.*, ICC Docket No. 10-0110 (Order Oct. 26, 2010), p. 10; *Aqua Illinois, Inc.*, ICC Docket No. 10-0194 (Order Dec. 2, 2010), pp. 13-14; *Galena Territory Utilities, Inc.*, ICC Docket No. 10-0280

(Order Dec. 15, 2010), pp. 5-6; *Northern Hills Water and Sewer Co.*, ICC Docket No. 10-0298 (Order Jan. 20, 2011), pp. 5-6; *Commonwealth Edison Co.*, ICC Docket No. 10-0467 (Order May 24, 2011), pp. 65-92 (also providing for a later rulemaking).

GCI's Initial Brief untimely and improperly reverted to the approach of GCI's witness' direct testimony, citing it and certain other documentary exhibits for the proposition that the Utilities had not supplied sufficient support for their rate case expenses. GCI's discussion was not only untimely and improper, but it was extremely inaccurate with regard to its claims about information supposedly not produced that in fact was produced and made part of the evidentiary record. The Utilities were not fairly allowed to respond in testimony, but, notwithstanding that, the evidence they provided and Staff's analysis more than sufficiently support the updated rate case expenses presented in the Utilities'' surrebuttal.

Commission Analysis and Conclusion

The Commission finds that the amounts of compensation for attorneys and technical experts to prepare and litigate this proceeding, as adjusted by Staff and updated in the Utilities' surrebuttal, are just and reasonable pursuant to Section 9-229 of the Act (220 ILCS 5/9-229). The Commission finds that the Utilities have provided sufficient support for all of their rate case expenses, as adjusted and updated. The expenses in question are a proper cost of doing business of a utility, and utilities have ample incentive to control them in a prudent and reasonable manner. Therefore, the Commission approves the Utilities' rate case expenses as revised in their surrebuttal and rejects GCI's unsupported "sharing" proposal.

(ii) Amortization of Rate Case Expenses Associated <u>With Docket Nos. 09-0166/0167 (cons)</u>

North Shore and Peoples Gas

North Shore and Peoples Gas proposed to amortize the remaining unamortized rate case expenses of their 2009 rate cases as of 2012 over a two year amortization period to avoid over-recovery in the rates being set in the instant cases. NS Ex. 6.0 at 13; PGL Ex. 6.0 at 13.

Other Parties

[Insert]

North Shore and Peoples Gas Response

Staff proposed that the calculation of the amount of 2009 rate case expenses to be amortized through the rates set in the instant case should be based on actual costs but capped by the level approved by the Commission in the 2009 rate cases, and also should exclude costs related to rehearing and appeals. The Utilities, in the interests of narrowing the issues, have agreed to the first of those two premises (as reflected in the

Utilities' figures), but disagree with the exclusion of rehearing and appeal costs. NS-PGL Ex. 39.0 Corr. at 6, 7. Staff's proposal to exclude rehearing and appeal costs should not be adopted because: rehearing and appeal processes are a common part of litigation of a general rate case filing, as exemplified by the facts that there are pending appeals in the Utilities' 2007 and 2009 rate cases and there were appeals from ComEd's 1999, 2001, 2005, 2007, and 2010 rate cases Orders. *Id.* at 6. Moreover, the Utilities are aware of no legal or ratemaking principle that bars or supports barring recovery of these costs.

GCI wrongly proposed (inconsistently with its normalization proposal) that even though the expenses in question were approved for recovery in the 2009 rate cases, recovery now should be barred on the theory that recovery somehow constitutes retroactive and single issue ratemaking. NS-PGL Ex. 39.0 Corr. at 5–6. Amortization of the 2009 rate cases expenses already was approved by the Commission's Order in those cases. *Peoples 2009*, pp. 42-43. The unamortized amount to be recovered through the rates being set here does not exceed what was approved then, as noted above. Illinois utilities in past rate case proceedings have been allowed by the Commission to recover remaining unamortized prior rate case expenses while seeking approval to recover new rate case expenses. This situation was addressed in ComEd's 2010 rate case, in which the Commission approved recovery of unamortized approved rate case expenses from ComEd's prior (2007) rate case as well as that 2010 case (and provided for the subject of rate case expenses to be addressed in a rulemaking process, as noted earlier). *ComEd 2010* at 59, 68; NS-PGL Ex. 39.0 Corr. at 6. Similarly, in ComEd's 2007 rate case, the Commission allowed recovery of unamortized approved rate case expenses from ComEd's prior (2005) rate case as well as that 2007 case, rejecting Mr. Effron's claim that the unamortized 2005 case expenses should be disallowed. *ComEd 2007* at 70-74. There is no basis for a different result here.

Commission Analysis and Conclusion

The Commission finds reasonable the agreement between the Utilities and Staff to calculate the amount of 2009 rate case expenses to be amortized through the rates set in the instant case based on actual costs but capped by the level approved by the Commission in the 2009 rate cases and recognizes that the Utilities' figures reflect this agreement. The Commission agrees with the Utilities that rehearing and appeal processes are a common part of litigation of a general rate case filing and, further, that there is no legal or ratemaking principle that bars or supports barring recovery of rehearing and appeal costs. Therefore, the Commission rejects Staff's proposal to exclude these costs. The Commission also rejects GCI's proposal to bar recovery of the expenses in question as it is inconsistent with Commission orders in past rate case proceedings that have allowed such recovery. Therefore, the Commission approves the Utilities' recovery of remaining unamortized 2009 rate cases expenses as modified per the Utilities' agreement with Staff.

(iii) Normalization of Rate Case Expenses

Other Parties

[Insert]

North Shore and Peoples Gas Response

GCI has never provided any valid basis for its proposal to "normalize" rate case expenses, which is inconsistent with its "50/50 sharing" proposal. Normalization can lead to over- or under-recovery just like the Commission's accepted amortization method, and the proposal seems premature in light of the rulemaking ordered in *ComEd 2010*, and thus both Staff and the Utilities oppose GCI's proposal. Staff Ex. 11.0 Corr. at 12–14; NS-PGL Ex. 22.0 2 Corr. at 15–16.

Commission Analysis and Conclusion

The Commission agrees with Staff and the Utilities that GCI's proposal is premature and, therefore, declines to normalize rate case expenses.

d. Gas Transportation Administrative Costs

The subject of Gas Transportation administrative charges is addressed in Section XI.C, XI.D.1, and XI.E.1.

e. Solicitation Expense

Staff

[Insert]

North Shore and Peoples Gas Response

The Utilities have reflected appropriate and reasonable cost-based figures for the IBS solicitation revenues relating to the Pipeline Protection Program ("PPP") offered by affiliate Peoples Energy Home Services ("PEHS") in their forecasts for the 2012 test year, a total of $16,572, so no adjustment is proper or necessary. NS-PGL Ex. 38.0 at 7–8, 9. Any errors made by IBS in prior years by not billing PEHS the right amounts do not alter the correctness of the 2012 test year figures. *Id*. at 9. Contrary to Staff's proposal to calculate the figures based on an estimate of the market value of the solicitation services provided by IBS to PEHS, the correct calculation is cost-based under the Master Non-Regulated Affiliated Interest Agreement. NS-PGL Ex. 38.0 at 7, 8.

Commission Analysis and Conclusion

The Commission finds that the Utilities' cost-based figures for the IBS solicitation revenues at issue are appropriate and reasonable. Therefore, the Commission rejects Staff's proposal to calculate the figures based on an estimate of the market value of these solicitation services.

7. Depreciation

a. Depreciation Expense on Forecasted Additions

As discussed in Section IV.C.1.a, the Utilities, in the interests of narrowing the issues, accepted Staff's proposed adjustment related to forecasted plant additions. There were errors in Staff's figures for the derivative impacts on depreciation expense of that plant additions adjustment, but the errors were corrected in the Utilities' corrected surrebuttal. NS-PGL Ex. 39.0 Corr. at 5. The Utilities believe that the corrected figures for the derivative impacts are not contested.

Commission Analysis and Conclusion

The Commission resolves the final figures for derivative impacts on depreciation expense of Staff's adjustment related to forecasted plant additions in accordance with the Commission's ruling on that adjustment discussed elsewhere in this Order.

b. Derivative Adjustments from Contested Adjustments

Setting aside the corrections discussed in Section V.C.7.a, *supra*, which the Utilities understand to have been resolved, the Utilities do not believe that there are any disputes over the correct calculation of depreciation expense impacts of contested plant adjustments. When the Utilities do contest a plant adjustment, then, of course, they also oppose the associated derivative impacts, including the impact on depreciation expense.

Commission Analysis and Conclusion

The Commission resolves the derivative impacts on depreciation expense in accordance with the Commission's rulings on the applicable contested adjustments discussed elsewhere in this Order.

8. Revenues

a. Repair Revenues

Other Parties

[Insert]

North Shore and Peoples Gas Response

Staff's proposal is incorrect. Under the Commission-approved Services and Transfers Agreement, which applies here, the Utilities are to bill PEHS at the Fully Distributed Cost (the "FDC") of providing the repair service. NS-PGL Ex. 38.0 at 10. The Utilities provided support for the FDC calculation. *Id.* at 10.

In 2008-2010, the Utilities missed billings totaling $7,174 for Peoples Gas and $910 for North Shore, and they originally did not include this item in their forecasted 2012 test year figures, but the Utilities' revised revenue requirements in surrebuttal reflect the correct amounts. NS-PGL Ex. 38.0 at 10. The Utilities are required to charge PEHS the FDC, and are not required to charge the same amount charged to customers. *Id*. at 11.

Commission Analysis and Conclusion

The Commission finds that the Utilities correctly charge PEHS the FDC for repair service in accordance with the Services and Transfers Agreement. Therefore, the Commission rejects Staff's proposed adjustments to the Utilities' repair revenues.

b. Other Issues Relating to PEHS and PPP, Including Staff Request for Investigation

Staff

[Insert]

North Shore and Peoples Gas Response

Staff's proposal for further Commission investigation of the PPP offered by PEHS is unwarranted. The amounts involved do not justify the burdens and costs of such steps. The impact of the 2012 test year solicitation revenues, properly calculated, on the Utilities' forecasts are just $16,572, as noted above. The missed billings for repairs in 2008 to 2010 were just a total of $7,174 for Peoples Gas and $910 for North Shore, as noted above. Larger amounts potentially would be at stake if the solicitation and repairs amounts were to be calculated as Staff proposes, but, as discussed earlier, Staff's proposals are incorrect.

Commission Analysis and Conclusion

The Commission agrees with the Utilities that no further investigation of the PPP offered by PEHS is warranted, especially given that Staff's proposals are based upon incorrect calculations of the solicitation and repairs amounts at issue. Therefore, the Commission declines to adopt Staff's proposal for a separate proceeding relating to the PPP.

c. Warranty Products (Revenue and Non-Revenue)

Other Parties

[Insert]

North Shore and Peoples Gas Response

IGS' proposal was untimely and lacks a valid legal basis as well as a sound factual basis. The Utilities made no proposal on this subject, nor did any party do so in their direct testimony. The proposal was made by IGS in rebuttal for the first time and the Utilities did not have a reasonable and fair time to analyze and respond in the five business days within which their surrebuttal was due. In addition, IGS has not made a convincing case for its proposal, which would impose obligations on the Utilities in relation to unaffiliated parties. Even if such a proposal were to be proper in some circumstance, it was untimely, the record is insufficient, and these cases are not a proper vehicle to address the proposal.

Commission Analysis and Conclusion

The Commission agrees with the Utilities that the IGS proposal was untimely, is problematic, and that the record is very insufficient for consideration of the proposal. The proposal is not adopted.

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

The Utilities do not believe that there is any contested proposal related to Taxes Other Than Income Taxes, except to the extent contested proposals on other subjects have a derivative impact here. When the Utilities do contest an adjustment elsewhere, then, of course, they also oppose the associated derivative impacts, including any impact here. The Commission resolves the derivative impacts on Taxes Other Than Income Taxes in accordance with the Commission's rulings on the applicable contested adjustments discussed elsewhere in this Order.

E. Income Taxes (Including Interest Synchronization) (Uncontested Except for Derivative Adjustments from Contested Adjustments)

The Utilities do not believe that there is any contested proposal related to Income Taxes, except to the extent contested proposals on other subjects have a derivative impact here. When the Utilities do contest an adjustment elsewhere, then, of course, they also oppose the associated derivative impacts, including any impact here. The Commission resolves the derivative impacts on Income Taxes in accordance with the Commission's rulings on the applicable contested adjustments discussed elsewhere in this Order.

F. Gross Revenue Conversion Factor

1. Uncollectible Rate

North Shore and Peoples Gas

The Utilities correctly have used the Gross Revenue Conversion Factor ("GRCF") of 1.711941 for North Shore and 1.744262 for Peoples Gas (as revised as of surrebuttal). NS-PGL Ex. 39.0 Corr. at 13.

Other Parties

[Insert]

North Shore and Peoples Gas Response

Staff's proposed net write-off method for uncollectibles expense would affect the uncollectibles rate portion of the GRCF calculations for the Utilities, NS-PGL Ex. 39.0 Corr. at 13, but the Utilities have demonstrated that Staff's proposal should not be adopted. *See* Section V.C.5, *supra*.

Commission Analysis and Conclusion

Because the Commission rejects Staff's proposed net write-off method for uncollectibles expense and the Commission finds the Utilities' Gross Revenue Conversion Factors to be appropriate, they are approved.

2. Derivative Adjustments from Contested Adjustments

The Utilities do not believe that, apart from the subject noted in Section V.F.1, *supra*, there is any other contested proposal related to the GRCF as such. Contested revenue requirement adjustments affect the level of revenues to which the GRCF is to be applied, but there is no issue as to the method of that calculation. The Commission resolves the derivative impacts on the GRCF in accordance with the Commission's rulings on the applicable contested adjustments discussed elsewhere in this Order.

VI. RATE OF RETURN

A. Overview

Peoples Gas proposes a rate of return on rate base of 8.11% based on a capital structure containing 56% common equity at a cost (a rate of return on common equity or "ROE") of 10.85% and 44% long-term debt at a cost of 4.62%. North Shore proposes a rate of return on rate base of 8.50% based on a capital structure containing 56% common equity at an ROE of 10.85% and 44% long-term debt at a cost of 5.51%.

Staff and GCI propose far lower rates of return of return on rate base, including lower rates of return on common equity. Staff proposes that Peoples Gas' authorized ROE be reduced from its current 10.23% to 8.75%, and that North Shore's authorized return be reduced from its current 10.33% to 8.75%. For its part, GCI recommends a range of ROEs for each Utility with a mid-point that is even lower than Staff proposes – 8.02%. Furthermore, Staff proposes to impute an artificial capital structure for the Utilities that includes short-term debt and reduces the amount of common equity. The capital structure proposed by Staff for Peoples Gas is 49% common equity, 48.4% long-term debt and 2.6% short-term debt. The capital structure proposed by Staff for North Shore is 50% common equity, 46.1% long-term debt and 3.9% short-term debt.

The legal standards governing a public utility's entitlement to a fair and reasonable return on its investment are well established and familiar. The Commission summarized these standards in the Utilities' last rate case thus:

> 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 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.' The authorized return on equity 'should be commensurate with returns on investments in other enterprises having corresponding risks. That return, however, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.'

Peoples 2009, pp. 89-90 (citations omitted).

B. <u>Capital Structure</u>

1. <u>North Shore</u> and 2. <u>Peoples Gas</u> (Combined Discussion)

North Shore and Peoples Gas

According to Utilities witness Ms. Gast, a strong capital structure benefits the Utilities' customers by maintaining ready access to capital in all market conditions, maintaining strong credit ratings and reducing their cost of debt. NS Ex. 2.0 at 6-7; PGL Ex. 2.0 at 6-7; NS-PGL Ex. 18.0 at 3. Accordingly, the Utilities each proposed a capital structure of 56% common equity and 44% long-term debt. NS Ex. 2.0 at 6; PGL Ex. 2.0 at 6. This capital structure is consistent with their currently authorized capital structures. *Peoples 2007*, p. 73; *Peoples 2009*, p. 93. It also approximates the Utilities' actual fiscal 2010 year-end capital structures, as well as their actual average structures over the past several years. NS Ex. 2.0 at 7-8; PGL Ex. 2.0 at 7-8. The Utilities' proposed capital structures also are comparable to those of the proxy group developed by the Utilities for developing their return on equity recommendations. NS Ex. 2.0 at 8; PGL Ex. 2.0 at 8. The Utilities propose no changes to their traditional practice of using short-term debt only to finance seasonal cash needs, particularly for purchased gas costs and short-term construction work in progress, and not as a permanent source of financing rate base investments. NS-PGL Ex. 18.0 at 12.

Staff

[Insert]

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities oppose Staff's proposal to impute artificial capital structures. The Utilities point to past Commission orders to argue that replacing a utility's actual forecasted capital structure with an imputed one is an extraordinary measure that the Commission takes only upon a convincing demonstration that the utility's customers would otherwise be unfairly burdened. "[I]mputing a hypothetical capital structure for ratemaking purposes to determine a utility's rates is a serious adjustment, and should only be adopted when a utility's actual capital structure is found to be unreasonable, imprudent, or unduly affected by such circumstances as double leverage so as to unfairly burden the utility's customers." *Illinois Commerce Comm'n v. Northern Ill. Gas Co.,* ICC Docket No. 87-0032, 1988 WL 1533285 at *23 (Order Jan. 20, 1988); *see also Northern Ill. Gas Co.,* ICC Docket 08-0363 (Order on Rehearing Oct. 7, 2009), at 12.

The Utilities state that Staff's proposal would weaken their capital structures in two different ways – by imputing short-term debt in their capital structures and by reducing the amount of equity in their capital structures. These changes would weaken the Utilities' actual structures because they will manage their capital structures to those authorized; otherwise, their shareholders will bear the cost of maintaining stronger capital structures. NS-PGL Ex. 35.0 at 7-8. Weakening their current and authorized capital structures, structures which have allowed them to maintain reasonably strong credit ratings, "could put downward pressure on the Utilities' current credit ratings." NS-PGL Ex. 20.0 at 15. Staff's proposal is unnecessary, harmful to shareholders and customers alike, and unsupported by the evidence.

The Utilities' proposed exclusion of short-term debt from their capital structures is consistent with this Commission's regulation of them over the past 20 plus years, and their planned use of short-term debt is consistent with their past practice that served as a basis for the Commission's decisions over that period. NS-PGL Ex. 18.0 at 11-12; NS-PGL Ex. 35.0 at 3-5. They emphasize that they issue short-debt debt only temporarily to manage short-term cash flows at certain times of the year, typically at year-end when higher winter revenues have not been collected and seasonal cash requirements are at their highest, and in the late summer months when revenues are at their lowest. NS-PGL Ex. 18.0 at 12; NS-PGL Ex. 35.0 at 4. Moreover, the Utilities point out that Staff did not dispute the Utilities' evidence that they use short-term debt exactly as they did prior to their last rate case. NS-PGL Ex. 18.0 at 12. Thus, the evidence demonstrates that they do not use short-term debt to fund rate base.

Therefore, the Utilities argue, the evidence fails to satisfy the burden established in our decision in *Northern Illinois Gas Company d/b/a Nicor Gas Company,* ICC Docket No. 04-0779 (Order Sept. 30, 2005), at 70-72, that a material change in circumstances since a utility's previous rate case order must be demonstrated to support the inclusion of short-term debt. Moreover, the Utilities rely upon the Commission's conclusion in their previous rate cases in which it approved the same capital structure which they propose in here, and the Commission's statement that: "Just as significant, only two years ago, the Commission approved the same capital structure that the Utilities propose in this case; the record shows no difference between how the Utilities use short term debt today and how they used it at that time." *Peoples 2009*, p. 93. The Utilities urge that the Commission to adopt the same logic in these rate cases.

The Utilities also oppose Staff's proposal to significantly decrease the proportion of equity to debt in their capital structures. The Utilities argue that the adoption of this adjustment to their capital structures would seriously impact their financial strength and essentially is a proposal to downgrade their credit ratings. The Utilities currently hold relatively strong credit ratings, with BBB+ "issuer" ratings and A/A- "issuance" ratings from S&P and A1 "issuance" ratings from Moody's. NS Ex. 2.4; PGL Ex. 2.4; NS-PGL Ex. 18.0 at 6. Further, S&P's rating outlook for the Utilities is "positive," which indicates that they are trending toward credit rating upgrades. NS-PGL Ex. 18.0 at 4. The Utilities assert that Staff's proposal to increase the leverage and risk in their capital structures would put them into S&P's "Aggressive" financial risk profile. NS-PGL Ex. 18.0 at 6. Combined with the Utilities' "Excellent" business risk profile, this level of financial risk would put the Utilities' in line for an issuer credit rating of BBB, which is lower than the Utilities' current BBB+ issuer rating and just one step above the lowest investment-grade rating of BBB-. *Id.*; NS-PGL Ex. 20.0 at 6. A credit rating downgrade would increase the Utilities' risk, capital costs and, ultimately, the rates that their customers must pay, making Staff's proposal contrary to customer interests. NS-PGL Ex. 20.0 at 7.

The Utilities further argue that Staff's proposal suffers from numerous methodological and factual flaws. First, Staff improperly used the ROE proxy Gas Group as a basis to impute capital, as a proxy is not needed to set a utility's capital structure because their capital structures can be derived from the Utilities' financial statements and their test year capital structures can be reliably forecast. NS-PGL Ex. 18.0 at 10. Second, misused the S&P financial risk matrix in making its comparison to the Gas Group in several ways, such as, for example, comparing the Utilities' forecasted financial performance with historical data pertaining to the Gas Group and ignoring that the Utilities' proposed capital structure falls within the range of current and forecasted capital structures of the Gas Group. NS-PGL Ex. 36.0 at 10. The Utilities point out that the Gas Group's forecasted long-term debt-to-permanent capital ratio of 42% is actually lower than the Utilities' current and proposed ratio of 44%. NS Ex. 2.0 at 7-8; PGL Ex. 2.0 at 8; NS Ex. 3.0 REV at 9-10; PGL Ex. 3.0 REV at 9. Moreover, the comparison Staff offered on rebuttal of the Utilities' financial ratios at different capital structures under Staff's proposed revenue requirement is invalid, because capital components and costs Staff used to develop the ratios were inconsistent with those that Staff used to develop its revenue requirements. Third, Staff fails to adjust its ROE recommendations based upon the change it proposes in their capital structure. The Utilities demonstrated that if Staff applied its financial risk adjustment methodology from their last two rate cases, the increased financial risk associated with the difference between the two ratings would require an increase in the Utilities' authorized ROE by 23 basis points. NS-PGL Ex. 18.0 at 6-7.

Commission Analysis and Conclusions

The Commission finds Utilities have satisfied their burden by a preponderance of the evidence that they will not use short-term debt to finance rate base in the test year. The Utilities propose to use short-term debt no differently than they have for at least the last 20 years, namely to borrow funds temporarily at times in the year when net cash balances and/or revenues are low. The same logic applies here as it did in *Peoples 2009*: only two years ago, the Commission approved the same capital structure that the Utilities propose in this case; the record shows no difference between how the Utilities use short term debt today and how they used it at that time. The Commission has repeatedly held that such use of short-term debt does not constitute the use of short-term debt to finance rate base, and Staff has not provided a compelling reason for the Commission to depart from its long-standing approach.

The Commission further finds that Staff has not adequately supported its position on significantly decreasing the ratio of equity to debt in the Utilities' capital structures. It does not appear that Staff has ever presented a "financial risk" analysis to establish the capital structure of a large electric or natural gas utility. In addition to the various methodological and data input issues raised by the Utilities pertaining to this non-standard analysis, we find that the resulting changes Staff proposes to the Utilities' capital structures would increase their risk and could lead to a downgrade of the their credit ratings, which would unnecessarily increase their capital costs and rates.

The Commission finds that the Utilities' proposed capital structures are in line with their actual capital structures, and we see no reason to depart from these capital structures that were approved in the Utilities' previous two rate cases. The Commission, therefore, approves the Utilities' proposed capital structures of 56% common equity and 44% long-term debt.

C. Cost of Long-Term Debt

1. North Shore (Uncontested)

North Shore accepted the Staff-adjusted average cost of long-term debt in 2012 for ratemaking purposes of 5.51%. Staff Ex. 4.3N; NS-PGL Ex. 18.0 at 13.

The Commission approves the North Shore figure as appropriate and uncontested.

2. Peoples Gas

Peoples Gas

Peoples Gas originally proposed a long-term debt cost of 4.97%. PGL Ex. 2.0 at 8-9. Staff agreed to remove Peoples Gas' Series OO long-term debt from its capital structure, as the debt was retired on August 18, 2011. Staff Ex. 13.0 at 2; NS-PGL Ex. 35.0 at 8. Peoples Gas accepted certain of Staff's adjustments to its long-term taxable debt, for a final proposal of 4.62% for the long-term debt cost for Peoples Gas. NS-PGL Ex. 35.0 at 9.

Staff

[Insert]

Other Parties

[Insert]

Peoples Gas Response

Peoples Gas opposes Staff's position that Peoples Gas' Series PP long-term debt continue to be included in the balance of its long-term debt unless and until the Commission enters an Order in Docket No. 11-0476 approving the purchase of the tax-exempt securities backed by Series PP. Staff's position fails to acknowledge that Peoples Gas did not need Commission approval to retire the Series PP bonds and that they were in fact retired in 2008. NS-PGL Ex. 35.0 at 8.

It is merely the "investment" (holding open the option of issuing tax-exempt debt in the future) that is awaiting Commission approval in Docket No. 11-0476. *Id*. Staff's position should be rejected because the Series PP long-term debt does not exist, and including it in Peoples Gas' long-term debt balances and costs for a 2012 test year would create an arbitrary disconnect between actual and forecasted long-term debt balances and related costs.

Commission Analysis and Conclusion

The Commission finds that Peoples Gas' proposed treatment of its Series PP long-term debt is reasonable in light of the fact that this long-term debt actually was retired and removed from long-term debt on Peoples Gas' balance sheet. The Commission agrees that its approval was not needed to retire the Series PP bonds, and that the exclusion of these bonds from Peoples Gas' cost of long-term debt will result in a more accurate outstanding debt balance for Peoples Gas for the 2012 test year. As adjusted, Peoples Gas' average cost of long-term debt in 2012 for ratemaking purposes is 4.62%. NS-PGL Ex. 35.0 at 9.

D. Cost of Short-Term Debt

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

The Commission finds, as stated above, that short-term debt should not be included in the Utilities' capital structures. Accordingly, this Order need not address the evidentiary record regarding the Utilities' costs of short-term debt.

E. Cost of Common Equity

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

a. Overview

Because the Utilities' common stock is not publicly traded, their cost of equity must be estimated using capital market and financial data relied on by investors to assess the relative risk of other natural gas utilities.

North Shore's and Peoples Gas' Overall Position

Utilities witness Mr. Moul presented three "market" measures of the Utilities' return on equity ("ROE") based on a proxy group of natural gas utilities. Mr. Moul found that the proxy group actually had lower overall investment risk than the Utilities, and recommended that this fact be taken into account when analyzing the results of these measures. NS Ex. 3.0 REV and PGL Ex. 3.0 REV, at 12-13. Mr. Moul applied the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM") and the Risk Premium model. Mr. Moul presented initial and updated results as follows:

Model	February	July
DCF	9.67%	9.03%
CAPM	11.21%	11.56%
Risk Premium	11.25%	11.25%

PGL Ex. 3.0 REV at 45 (table); NS-PGL Ex. 19.0 REV at 7 (table). Recommending that the DCF results be discounted or excluded, but recognizing the decline in that measure, Mr. Moul's updated ROE recommendation for each Utility was 10.85%. NS-PGL Ex. 19.0 REV at 7.

The Utilities state that Mr. Moul's recommended ROE is also supported by the "general context" in which the Commission must determine their cost of equity. The

Utilities urge the Commission to consider information beyond the traditional mathematical models used to estimate the market cost of equity, because each model relies on different assumptions and has its own limitations. PGL Ex. 3.0 REV at 2-3. The Utilities point to the Commission's recognition in their last rate cases of the need to check the results of these models against financial market information to ensure that the Commission's decisions on a utility's ROE is consistent with "real world conditions." *Peoples 2009*, p. 23.

Utilities witness Steven Fetter, a former chair of the Michigan commission and former officer of the Fitch credit rating agency, described the unique risks that affect a utility's capital costs. A natural gas utility's business is naturally capital-intensive and its duty to serve requires it to go to the financial markets to raise capital for investment in its system and procure sufficient gas supply regardless of the state of the financial or natural gas markets. Non-regulated companies have much better ability to defer investment and spending decisions in response to unfavorable market conditions. NS-PGL Ex. 20.0 at 7-8. These are not theoretical concerns. The Utilities were required to access the capital markets three years ago when the markets almost shut down in the wake of the financial crisis, and were able to do so due to their financial strength and relatively strong credit ratings. *Id.* at 10; NS-PGL Ex. 18.0 at 3.

Mr. Fetter also explained the increasing importance of this Commission's ratemaking decisions on the Utilities' ability to maintain investment grade credit ratings and reasonable capital costs. The quality and direction of regulation, in particular the ability to recover costs and earn a reasonable return, are among the most important considerations when a credit rating agency assesses utility credit quality and assigns credit ratings. NS-PGL Ex. 20.0 at 8-9. It is also a key consideration in investors' decisions about whether to invest in utilities as opposed to other industries. "Utility investors understand and accept the role of pervasive regulation, but they seek from the regulatory process decision-making that is fair, with a significant degree of predictability." *Id.* at 9. The financial markets' focus on the quality and direction of regulation has sharpened following the 2008 credit crisis and the volatility in credit access and cost that has ensued. *Id.* at 10-11. Mr. Fetter concluded that if ROEs "anywhere near" those recommended by Staff or GCI were adopted, the Utilities' currently strong credit ratings would be jeopardized. *Id*. at 13-14.

Further, the Utilities presented evidence establishing that state commissions play a very real part in "making the market" for utility capital, as the quality and direction of regulation affect the utility's investment risk. NS-PGL Ex. 20.0 at 11-13; NS-PGL Ex. 37.0 at 2-3. The Utilities' current (10.33% North Shore and 10.23% Peoples Gas) and proposed (10.85%) ROEs are well within the range of utility ROEs recently authorized by this Commission and other state commissions throughout the country. NS-PGL Ex. 20.0 at 13-14; NS-PGL Ex. 19.0 REV at 3; NS-PGL Exs. 20.2 and 20.3. The evidence demonstrated that the average return that was set for energy utilities nationally in 2009-2010 was 10.32%. NS-PGL Ex. 19.0 REV at 2-3; NS-PGL Ex. 19.1.

By contrast, the Utilities point out that Staff and GCI proposed ROEs would be lower than any ROE this Commission has authorized for any natural gas utility since at least 1972. NS-PGL Ex. 17.0 at 6. The Utilities further show that Staff and GCI proposed ROEs would be lower than any ROE authorized anywhere in the country in the last two years, and there has been only one (in Connecticut, the state rated the absolute lowest for regulatory quality) as low as Staff's 8.75% proposal and none near the mid-point of GCI's proposals in the last five years. NS-PGL Ex. 19.0 REV at 3; NS-PGL Ex. 19.1; NS-PGL Ex. 20.0 at 13-14; NS-PGL Ex. 20.2. Even over the last twenty years, there have been no ROEs near GCI's level and only the lone Connecticut return at the level of Staff's proposal. NS-PGL Ex. 20.0 at 14; NS-PGL Ex. 20.3.

The Utilities argue that all of these considerations support an increase of the Utilities' cost of equity to the 10.85% level calculated by Mr. Moul.

Staff's Overall Position

[Insert]

GCI's Overall Position

[Insert]

b. <u>Proxy Group Analysis</u>

North Shore and Peoples Gas

Because the Utilities' stock is not publicly traded, in order to estimate their market cost of equity mathematical models must be applied to a proxy group of publicly-traded companies with an investment risk profile similar to the Utilities. NS Ex. 3.0 REV & PGL Ex. 3.0 REV at 3. As in the Utilities' last two rate cases, Utilities witness Mr. Moul assembled a group of publicly-traded natural gas utilities to serve as the "Gas Group." Using the same methodology, Mr. Moul conducted a "fundamental risk analysis" to determine whether the investment risk of the Gas Group and the Utilities was similar. NS Ex. 3.0 REV at 6- 12; PGL Ex. 3.0 REV at 6-12; NS Exs. 3.2 – 3.5; PGL Exs. 3.2 – 3.5. Based on this thorough analysis, Mr. Moul concluded that the Gas Group had lower overall investment risk than the Utilities. NS Ex. 3.0 REV at 12-13; PGL Ex. 3.0 REV at 12-13. But he found it impractical to come up with a group with similar risk because of the very small number of candidate gas utilities. Therefore, he recommended that the ROEs set for the Utilities should recognize their "higher risk characteristics." NS Ex. 3.0 REV & PGL Ex. 3.0 REV at 13.

The ROE witnesses for Staff and GCI relied on Mr. Moul's Gas Group to run their models. In his direct testimony, Staff witness Mr. McNally testified that he "adopted the same group of gas utility companies that Companies' witness Moul used in his estimate of the return on common equity for North Shore and Peoples Gas. I believe that Mr. Moul's sample companies provide reasonable proxies for the operating risk of North Shore and Peoples Gas." Staff Ex. 5.0 at 2. GCI witness Mr. Thomas questioned Mr.

Moul's finding that all companies in the Gas Group had some form of decoupling but offered no evidence to contradict it, and relied on Mr. Moul's models to derive GCI's ROE proposal. GCI Ex. 5.0 at 3, 9.

Staff

[Insert]

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities contend that Mr. McNally's position in his rebuttal testimony that the investment risk of the Gas Group was higher than the Utilities was an untimely change in position that was based on a newly produced "principal components analysis." Staff's principal components analysis should be disregarded or stricken because of a failure by Staff to disclose sufficient information concerning how the analysis was performed and the data used, as well as a number of problems with the data itself and the methodology used by Staff. *See* NS-PGL Init. Br. at 106-110. Thus, the Utilities urge the Commission to adopt the conclusion of Mr. Moul that the Gas Group has lower risk than the Utilities and use that conclusion in guiding the Commission's evaluation of the financial models and other evidence pertaining to the Utilities' cost of equity.

c. <u>DCF</u>

North Shore and Peoples Gas

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. NS Ex. 3.0 REV & PGL Ex. 3.0 REV at 14-15. Mr. Moul estimated the dividend yield for the Gas Group by calculating its six-month average dividend yield, adjusting that average by three generally accepted methods to reflect investors' expected cash flows, and the averaging the three adjusted values. *Id*. at 15. For the investor-expected growth rate, Mr. Moul evaluated an array of historical and forecast growth data from sources that are publicly available to, and relied upon by, investors and analysts. *Id*. at 21-22. He focused on forecasts of earnings per share growth because empirical evidence supports it and because that they are most relevant to investors' total return expectations. *Id*. at 21. He selected 5.00%, the approximate mid-point for the Gas Group. *Id*. at 22. Mr. Moul then applied a financial leverage adjustment to his DCF results because they are based on market prices of the Gas Group's stock, which imply a capital structure with more equity and less financial risk, but are applied to utility book values, which imply a capital structure with less equity and more financial risk. *Id*. at 23-28.

Mr. Moul demonstrated that unique circumstances at play in today's unsettled economy are causing the DCF model to generate unreliably low measures of the Gas Group's equity cost. Growth prospects for natural gas utilities have eroded significantly due to the economic recession and dividend yields among the Gas Group remain low due to the low interest rate environment. NS Ex. 3.0 REV & PGL Ex. 3.0 REV at 5. While the Gas Group's growth rates have fallen 32% on average since the Utilities' last rate cases, their stock prices have increased by 36% on average. Growth in stock prices while growth rates are falling is an anomalous situation that cannot be sustained. NS-PGL Ex. 19.0 REV at 16-17.

Mr. Moul tested his conclusion by running his models on a gas and electric utility combination proxy group (the "Combination Group") and found that the DCF yielded a cost of equity of 11.22% in February and of 10.48% in July:

Combination Group Financial Model Results

Model	February	July
DCF	11.22	10.48%
CAPM	11.45%	11.71%
Risk Premium	11.25%	11.25%

Id. at 7. In each case, the Combination Group DCF results are higher and much closer to the CAPM and Risk Premium results for the Gas Group. NS Ex. 3.0 REV at 5-6; NS-PGL Ex. 19.0 REV at 9. The Utilities argue that these results confirm Mr. Moul's opinion that contradictory and anomalous trends unique to the natural gas industry – stock price growth and growth rate decline – make the DCF model currently an unreliable measure of equity cost for the Gas Group.

Staff

[Insert]

Other Parties

[Insert]

North Shore and Peoples Gas Response

As they did in their last rate case, the Utilities urge the Commission to reject Staff's use of single-day spot data, arguing that it invites subjectivity and error. The day, obviously, can be selected by the analyst and this can lead to gamesmanship. In addition, the results based on the day's data can be erroneous because there is evidence that short-term inefficiencies exist in stock prices, especially in periods of high volatility. NS-PGL Ex. 19.0 REV at 11-12. Here, the day from several months ago chosen by Staff (May 12, 2011) generated a DCF result of only 8.50%, which is over 100 basis points below the ROEs the Commission set for the Utilities in January 2010.

The Utilities further argue that Staff failed to meet the conditions the Commission has put on the use of spot data. In the Utilities' 2007 rate cases, the Commission rejected Staff's DCF result because it generated "anomalous" results, and instructed that a low result should lead Staff to "check" its results by "the use of an alternative sample date or an average across a six-month, or other, period…." *Peoples 2007,* p. 92. In the Utilities' last rate case, the Commission directed that parties relying on spot data make the following showing:

> The Utilities argue that spot data is exposed to inefficiencies from a number of sources and that Staff's reliance on such data without considering what it represents is itself arbitrary. We agree that it would be useful for the Commission to be told the conditions or financial climate of the spot day and whether any of these might cause material market inefficiencies. And, more importantly, we would expect the expert to be acutely attuned to that environment in making a selection. The choice of a spot day may be random or informed and we prefer some reasonable combination of both.

Peoples 2009, pp. 125-126. The Utilities assert that Staff met none of these requirements in presenting its extremely low 8.50% DCF result.

The Utilities further argue that the unreliability of using spot data, especially in a volatile market, is proven by the fact that Staff's DCF result increased by 48 basis points between its direct and rebuttal, likely due to the decrease in the Gas Group companies' stock prices during that period. Staff Ex. 14.0 at 9-10; Staff Ex. 14.0 at 9-10; NS-PGL Ex. 19.0 REV at 12-13. at 12-13. The Utilities also highlight that while Staff admits to using different sources of growth rates on different days, Staff fails to explain or justify this variation. Staff Ex. 14.0 at 10, fn. 20.

The Utilities assert that Mr. Moul's growth rates are sustainable and refute Staff's criticisms of Mr. Moul's growth rates. With respect to Mr. Moul's selection of a Morningstar growth rate as one of four sources he consulted, Mr. Moul demonstrated that the Morningstar rate was "entirely consistent with the (b x r) plus (s x v) formulation of sustainable growth." NS-PGL Ex. 19.0 REV at 18. In further response to Staff's criticism that Mr. Moul wrongly assumed that all new stock is issued at market price, the Utilities presented evidence showing that stock and stock options issued as part of compensation are issued at market price. NS-PGL Ex. 35.0 at 10-11. Moreover, Mr. Moul's growth rate analysis reflected only stock shares expected to be issued and did not include stock options that are not subsequently exercised in the future. NS-PGL Ex. 36.0 at 6; NS-PGL Ex. 19.12.

Staff and GCI oppose Mr. Moul's financial leverage adjustment, and although the Utilities acknowledge that the Commission rejected Mr. Moul's adjustment in the

Utilities' last two rate cases, they assert that this adjustment is fundamentally different than a "market-to-book" adjustment because it is not intended to maintain any given market-to-book ratio. Rather, Mr. Moul's financial leverage adjustment is intended to reflect the market's evaluation of risk associated with capital structure by correcting the error involved in applying a market-based cost of equity to a book value capital structure. NS-PGL Init. Br. at 118-120. The Utilities argue that a simple example demonstrates the need for Mr. Moul's financial leverage adjustment. If a utility's market value equity is worth $1000, with a capital structure of $600 equity and $400 debt, but based on book valuation the equity has only $500 in value. The company's market cost of equity based on its market value capital structure is 10%, implying a total dollar cost of equity of $60, but with the book value of equity being only $500, a rate of 12% would be needed to generate the $60 expected by the market. Thus, only by adjusting the utility's authorized return to 12% can the utility generate an adequate amount of earnings on its book value capital structure. NS-PGL Init. Br. at 119. The Utilities argue that the leverage adjustment is needed simply to correct their under-recovery of total dollar cost of equity because their market cost of equity based on their market value capital structures are applied to their book value capital structures. *Id*. at 120.

Additionally, the Utilities argue that the large differences between the Utility and Staff DCF results in the instant cases and those in the Utilities' last rate cases demonstrates that the DCF model is not producing reliable results. NS-PGL Init. Br. at 116-117. The Utilities posit that the 326-basis point drop in Staff's results in two years' time shown by this analysis cannot be explained and thus, Staff's results in this case are too disparate to represent the products of a valid model, and is additional proof that results from the DCF models should not be considered here.

d. <u>CAPM</u>

North Shore and Peoples Gas

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. 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. For the risk-free rate of return, Mr. Moul used historical and forecast yields on 20-year Treasury bonds and selected a mid-point of 4.25% based on recent historical trends and current forecast. NS Ex. 3.0 REV & PGL Ex. 3.0 REV at 37-38. For the beta measurement of systematic risk, he used the average *Value Line* beta for the Gas Group, adjusted using the Hamada formula to reflect the application of this market-based measurement to the utility's book value capital structure used in ratemaking. *Id*. at 36-37. Mr. Moul developed his market premium by averaging forecast data from *Value Line* and the S&P 500 Composite and historical data from Ibbotson Associates, all of which are sources routinely used by investors, analysts and academics. *Id*. at 39-40. Mr. Moul also adjusted his CAPM result for the relatively small size of the Gas Group, correcting a tendency of the CAPM to understate the cost of equity of smaller companies. *Id*. at 40-41.

Staff

[Insert]

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities showed that Staff's CAPM betas are biased on the low side. There are numerous published sources that provide calculated betas on firms, sources that are readily available to and relied on by investors and analysts. Staff relied on two of them, Value Line and Zacks. Staff Ex. 5.0 at 13. Staff, however, also calculated its own "regression beta" and then "adjusted the raw beta to produce a more accurate forward-looking beta estimate." *Id.,* 14-16. Given that the object of the exercise is to determine the investor required return on equity, the Utilities assert that separately calculated betas are not necessary as no investor could possibly rely on them. More important, Mr. Moul testified that in his experience there is a downward bias in Staff's betas, "which have always been lower than Value Line betas." NS-PGL Ex. 19.0 REV at 20. In his rebuttal, Mr. McNally did not dispute Mr. Moul's characterization.

GCI's use of lower betas (GCI Ex. 5.0 at 33 (Table 4)) was inappropriate because they are based on sources that do not publish their methodologies and data sources, and are therefore not as reliable as Value Line. Moul Tr. 8/31/11 491- 492.

There are also problems with Staff's spot day quotes of the risk-free rate for its CAPM model. Staff's quotes were inconsistent with Blue Chip and Global Insight forecasts of Treasury yields, which both indicate such rates increasing in the future beginning in 2012. NS-PGL Ex. 19.0 REV at 19- 20. Even the newer interest rate forecasts that Staff was allowed to introduce through Mr. Moul at the hearing (dated as late as August 29, 2011, the day the hearing started) were higher than the May 2011 rates Staff relied on. Moul Tr. 8/31/11 at 489-491 (5.0% forecast for 30-year Treasury bonds); Staff Cross Ex. 6; *compare* Staff Ex. 5.0 at 10 (4.42% current yield for 30-year Treasury bonds). The forecast information is by definition a more reliable basis on which to establish the Utilities' rates for a future test year, and that Staff's refusal even to consider how data from a single day over four months ago might change in the future is by definition arbitrary.

Further, while Staff and GCI witness Mr. Thomas deletes Mr. Moul's size adjustment from his CAPM analysis, Mr. Moul identified in detail the theory and literature supporting the general proposition that the smaller the firm, the greater its risk. NS Ex. 3.0 REV & PGL Ex. 3.0 REV. Moreover, Mr. Moul's adjustment is unique to the CAPM because it can significantly understate the cost of equity of smaller firms, including utilities. *Id.*

e. Risk Premium

North Shore and Peoples Gas

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. *See* NS Ex. 3.0 REV & PGL Ex. 3.0 REV at 29-30. Mr. Moul estimated a 5.75% prospective yield on A-rated utility bonds based on historical and forecasted yields. *Id*. at 30-32. Mr. Moul determined a risk premium of 5.50% by analyzing results for S&P Public Utilities and then adjusting those results based upon the results of his fundamental risk analysis in comparing the results for the S&P Public Utilities to the Gas Group. *Id*. at 32-35. Mr. Moul's risk premium analysis thus provided a cost of equity of 11.25%. *Id*. at 35.

Staff

[Insert]

Other Parties

[Insert]

North Shore and Peoples Gas Response

Staff criticizes Mr. Moul's use of historical data in his analyses, in particular in developing his equity premium estimate. Staff argues that using such data "falsely assumes that market data will revert to a mean," which is an inappropriate measure for the "random walk" of returns. Staff Ex. 5.0 at 23-24. Mr. Moul explained that he tailored his risk premium to the market fundamentals most likely to exist in the future, and thus he gave the greatest emphasis to more recent data. *Id*. at 21. Also, the Utilities argued that Mr. Moul took a balanced approach by using a premium for the S&P Public Utilities which is between the lowest premium and the highest premium. *Id*. The evidence also demonstrated that the differences in composition of the companies that comprise the S&P Public Utilities and the Gas Group support Mr. Moul's determination of a 5.50% risk premium for the Gas Group. *Id*. at 22. The Utilities emphasize that, contrary to Mr. McNally's characterization, Mr. Moul's model is not based exclusively on historical data and even when he used such data he evaluated its reasonableness under current market conditions. *See* NS-PGL Ex. 19.0 REV at 20-22.

f. Effect of Riders UEA and ICR

Staff

[Insert]

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities oppose Mr. McNally's recommendation to make a 10-basis point adjustment for Rider UEA. The Utilities argue that this additional adjustment is unnecessary because in their last rate cases, the Commission already made a 20 basis point adjustment for the fact that the legislation authorizing Rider UEA was enacted. *Peoples 2009*, pp. 128-129. Because Rider UEA has been in effect for the Utilities, there can be no change in their risk since their last rate cases. NS-PGL Ex. 19.0 REV at 24.

The Utilities also challenge Mr. McNally's proposed 183-basis point adjustment for Peoples Gas' Rider ICR. As demonstrated by Mr. Moul, this would result in Rider ICR providing virtually no spread over public utility bond yields, and the absence of a meaningful spread proves that the proposed adjustment is not credible. NS-PGL Ex. 19.0 REV at 24-25. Moreover, Peoples Gas argues that recovery under Rider ICR is not entirely automatic, given that it only covers incremental costs above a baseline, has an earnings cap, has a guaranteed savings amount, and has a reconciliation provision that includes prudence review. *Id*.

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

(i) <u>The Context</u>

Traditionally, the Commission has established rates of return on common equity for utilities by employing mathematical models designed to quantify the likely cost of attracting capital investment during the time rates are expected to be in effect. In virtually all cases, we have relied on the DCF and CAPM models. In their last rate cases, the Utilities urged the Commission also to consider the ROEs approved in previous cases by this and other commissions for purposes of understanding the real world impact our decision as to the Utilities' ROE might have, such as a change to their credit ratings.

While we adhere to the position that the Commission does not base utility returns on those approved for other utilities, in Illinois or elsewhere, we do agree that we have an obligation to consider how our decisions will be perceived by the financial markets and what impact that might have on the Utilities, and thus, ultimately their customers. The Utilities have provided convincing evidence that the Commission should take notice, through verifiable and well regarded sources, of general market conditions and trends because this information affects directly the decisions that investors make in the market. This information is relevant to our ROE decisions because we determine what investors demand and that requires consideration of the full array of information that investors consider when they effectively set the real cost of capital for a utility. *See Illinois Bell Tel. Co.,* ICC Docket Nos. 92-0448, 93-0239 (Cons.), at 103 (Order Oct. 11, 1994). It is also important that we are apprised of current market conditions because our decisions affect at least in part the capital costs that the market sets for the Utilities, in particular through the credit rating agencies' evaluation of regulation quality and direction. We would be remiss if we ignored altogether, as Staff and GCI urge, the potential market reactions to our cost of capital decisions.

The question that remains is what we should do with that information. We find that Utilities witnesses Messrs. Moul and Fetter provide a reasonable approach, namely that we consider general market conditions and trends, including returns recently approved by this and other commissions, in evaluating the various cost of equity analyses presented by the various analysts in our cases. We will assume that analyst recommendations that appear to be outside the range of what investors would expect are methodologically flawed, the product of unreasonable subjectivity, or both. Our decision here expands upon the principle that we enunciated in one of the Utilities' previous rate cases, when we rejected Staff's DCF analysis on the finding that it strayed "from a zone of reasonableness to the degree where it offers an unreliable estimate of the appropriate ROE." *Peoples 2007*, p. 92. Accordingly, we will endeavor to base our ROE decisions on financial model results that fall within a reasonable range of investor expectations as indicated by contextual evidence of "real world" conditions, such as general market conditions and returns recently approved by this Commission and others.

In these cases, we find the information on general market conditions and trends provided by the Utilities to be useful – but not determinative – in our consideration of various financial model results presented. We find the observations of Utilities witness Mr. Fetter particularly useful in placing our decision in a context informed by both market and regulatory realities. We reject the countervailing views of GCI witness Mr. Thomas, whose overemphasis on "objectivity" and "subjectivity" belies the extreme bias reflected in his observations of general market conditions and trends.

(ii) <u>The DCF Model</u>

In reviewing the results from the DCF model as performed by the Utilities, Staff and GCI, the Commission agrees with Mr. Moul that the results currently being generated by this model for natural gas utilities do not reliably measure the cost of equity for the Gas Group, and thus, the Utilities. This is shown not only in comparing the results from the DCF and other models in this case, but also in the disparity in the results from the DCF model in this case and from the Utilities' last rate cases a mere two years ago. It is clear that this model is producing results that diverge from real world financial conditions. Accordingly, the Commission will exclude the results of the DCF models in determining the Utilities' ROEs in these cases. This conclusion is further supported by the evidence presented by Mr. Moul that the investment risk of the Utilities is even higher than that of the Gas Group, which supports making such an adjustment.

In the alternative, if the Commission does NOT exclude the DCF model:

Staff's DCF analysis is based in large part on the stock prices for the utilities in the Gas Group on a single day in May of this year. The Utilities argue that such "spot" data is too exposed to inefficiencies caused by any number of causes, and that Staff's blind reliance on such data without considering its representativeness in light of general market conditions and trends is arbitrary. The Utilities rely on our decisions in their last two rate cases as establishing a standard for the use of such spot data.

The Commission hereby confirms what it stated in *Peoples 2007* and *Peoples 2009* concerning the use of spot data in a DCF model analysis. In those decisions, we made it abundantly clear that if the use of spot data produces a DCF result that is "anomalous," it must be checked. *Peoples 2007*, p. 92. Moreover, we stated that the Commission would expect to be told the conditions or financial climate of the spot day and whether any of these might cause material market inefficiencies, and that the expert be acutely attuned to that environment in making a selection. *Peoples 2009*, pp. 125-126. Here, Staff's DCF model analysis resulted in a proposed ROE of 8.50%, which, as shown in the evidence presented by the Utilities, is lower than any ROE authorized by this Commission since at least 1972, and lower than any ROE authorized anywhere in the country in the last five years. It is also over 300 basis points lower than Staff's DCF model result in the Utilities' last rate cases just two years ago. Yet, Staff failed to perform the type of check we stated was necessary in such a scenario in *Peoples 2007*. Nor did Staff provide the information we deemed necessary in *Peoples 2009*. Accordingly, as in *Peoples 2007*, the Commission determines that the result from Staff's DCF is too anomalous, in the absence of a check or other supporting information concerning the conditions and financial climate surrounding the data used, upon which to base a decision for the Utilities' ROEs.

In reviewing Mr. Moul's DCF model analysis, although we acknowledge that analysts might disagree as to different variants and ways in which a model might be constructed, we deem his methodology to be reasoned and sound. The Commission also finds that Mr. Moul presented sufficient evidence to establish that his growth rates are reasonable.

Turning to Mr. Moul's financial leverage adjustment to his DCF result, we note that we rejected Mr. Moul's financial leverage adjustment in the Utilities' last rate cases, finding that the Utilities' failed to differentiate this adjustment from the "market-to-book" adjustment that the Commission has repeatedly rejected. The record in the present cases, however, demonstrates that this is not the case. We find a fundamental difference in the two types of adjustments, and therefore that the Utilities' proposed financial leverage adjustment is not only supported by cost of equity theory but also the basic legal principle that a utility is entitled to an opportunity to earn a reasonable return on its investment.

The financial leverage adjustment is based on the well-accepted, if not irrefutable, economic theory that there is a direct relationship between a firm's risk and the amount of debt in its capital structure. Currently, there is no dispute that the Utilities' market value capital structure has more equity (and therefore less risk) than its book value capital structure. When the financial market models are used, the utility's cost of equity is estimated based on the proxy group's average market value capital structure. In order to make this result relevant to the utility's book value capital structure, an adjustment is required. Otherwise, if the market value cost of equity is applied to the utility's book value capital structure (and all other things are held equal), the utility will not recover its total cost of capital and will not earn its authorized return. NS-PGL Init. Br. at 120. Such a result would be confiscatory and therefore unconstitutional. Using well-accepted formulas, Mr. Moul calculated the Gas Group's ROE with and without a debt component, and determined the ROE of the Gas Group with its average debt ratio to be 51 basis points higher than its ROE with no debt in its capital structure.

Absent any competing calculation of this adjustment, we find that 51 basis points is a reasonable accommodation for the necessity of applying the market-based DCF ROE to a book value capital structure.

While we acknowledge Mr. Moul's recommendation to exclude the result of his DCF analysis as also being too anomalous, the Commission disagrees, and will consider the results of Mr. Moul's DCF analysis, with his leverage adjustment, in determining the Utilities' ROEs.

(iii) <u>The CAPM Model</u>

We find that the Utilities' CAPM analyses present an appropriate basis to determine ROE. For the reasons set forth above, Mr. Moul's consideration of historical information in conjunction with current and forecast data is a reasonable approach for this financial model. We also find persuasive Mr. Moul's justification for relying on *Value Line* betas to the exclusion of other sources. His testimony at the hearing demonstrated that, he has investigated the methodologies and data sources used by *Value Line* and its competitors and found *Value Line* to be the only source of betas that is transparent and replicable. Furthermore, we find that a size adjustment to the CAPM is reasonable though not required adjustment.

(iv) <u>Risk Premium Analysis</u>

We find that the evidence presented by the Utilities as to Mr. Moul's use of historical data and A-rated utility bonds to develop his risk premium analysis ROE recommendation demonstrated that Mr. Moul performed this analysis in a well-reasoned and methodologically sound manner. Thus, the Commission concludes that it is appropriate to include the results from this model in its determination of the Utilities' ROEs.

(v) <u>Adjustments for Riders UEA and ICR</u>

With respect to Rider UEA, the Commission already approved a 20-basis point adjustment based upon the legislation that authorized Rider UEA being enacted. *Peoples 2009*, pp. 128-129. Consequently, the Commission finds that Staff has failed to establish the need for an additional 10-basis point adjustment in these rate cases, and this proposal is not accepted.

As to Rider ICR, the Commission finds that Staff's proposed adjustment for the ROE factor is excessive. Although the Commission agrees that Rider ICR reduces Peoples Gas' risk associated with cash flow, the extent of that risk reduction depends on variables that cannot be accounted for, at least on this record. Therefore, we make no adjustment in Peoples Gas' ROE for Rider ICR.

(vi) Conclusions

Based on the foregoing discussion, the calculation of ROE will be affected by the following conclusions: (1) the DCF analyses performed by the Utilities, Staff and GCI will be excluded in this calculation, based on anomalous nature of this model's results and the comparative risk analysis performed by Mr. Moul [**alternatively,** "the DCF analysis performed by the Utilities will be included in this calculation"]; (2) the CAPM analyses of Staff and the Utilities will be included in this calculation; (3) the Utilities' financial leverage adjustment is approved; (4) Staff's adjustments for Rider UEA and Rider ICR are rejected; (5) these decisions have been informed by evidence regarding general capital market conditions and trends, including ROEs approved by this and other commissions.

Based on its review of the record, and consistent with the conclusions above, the Commission finds that an average of the Utilities' adjusted CAPM and Risk Premium models forms an appropriate basis to determine ROE, which results in 10.85%.

F. Weighted Average Cost of Capital

1. North Shore

Based on the evidence in the record and the applicable legal principles, the Commission approves as just and reasonable an overall rate of return (weighted average cost of capital) for North Shore of 8.50%, calculated as follows:

North Shore Cost of Capital Summary			
Cost of Capital	**Percent of Total**	**Percent Cost**	**Weighted Cost**
Long Term Debt	44.00%	5.51%	2.42%
Common Equity	56.00%	10.85%	6.08%
Total Capital			8.50%

2. Peoples Gas

Based on the evidence in the record and the applicable legal principles, the Commission approves as just and reasonable an overall rate of return (weighted average cost of capital) for Peoples Gas of 8.11%, calculated as follows:

Peoples Gas Cost of Capital Summary			
Cost of Capital	**Percent of Total**	**Percent Cost**	**Weighted Cost**
Long Term Debt	44.00%	4.62%	2.03%
Common Equity	56.00%	10.85%	6.08%
Total Capital			8.11%

VII. WEATHER NORMALIZATION – AVERAGING PERIOD (Uncontested)

The Utilities proposed using the average of the previous twelve years of weather data, ending in 2009, which results in 6,016 heating degree days for non-leap years and 6,036 heating degree days for leap years. PGL Ex. 4.0 at 10; NS Ex. 4.0 at 10. No party disagreed.

The Commission finds that the proposed average is reasonable and appropriate.

VIII. RIDERS – NON-TRANSPORTATION

A. Riders UEA and UEA-GC

North Shore and Peoples Gas

To comply with a Commission-approved Stipulation in Docket Nos. 09-0419/09-0420 (cons.), the Utilities each proposed new Rider UEA-GC, Uncollectible Expense Adjustment-Gas Costs. Utilities witness Ms. Grace explained that this rider would recover gas cost related Account No. 904, Uncollectible Accounts Expense, costs through a factor applied to customers' bills, rather than base rates. The Utilities also proposed changes to Rider UEA, Uncollectible Expense Adjustment, to effect a transition to Rider UEA-GC. NS Ex. 12.0 REV at 52-53; PGL Ex. 12.0 REV at 55-56; NS-PGL Ex. 28.2. Also, effective June 1, 2013, the Utilities proposed elimination of the Incremental Transportation Uncollectible Amount ("ITUA"), which recovers or refunds incremental Account No. 904 amounts related to transportation service. Ms. Grace explained that many transportation accounts are aggregated into pools, and the Utilities receive credit assurances; any uncollectible amounts would be minimal and eliminating the ITUA is appropriate. NS Ex. 12.0 REV at 53-54; PGL Ex. 12.0 REV at 56-57. The factors applied to the gas charge portion of sales customers' bills are derived from the allocation of Account No. 904 costs for each service classification in the embedded cost of service studies ("ECOSSs"). If the Commission approves the rider, amounts that would be recovered under the rider would need to be removed from the Utilities' revenue requirements. Rider UEA-GC adjustments would become effective when the proposed rates take effect. NS Ex. 12.0 REV at 52-53; PGL Ex. 12.0 REV at 55-56.

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities accepted certain of Staff witness Mr. Kahle's proposed revisions to the riders but opposed his recommended use of the net write-off method to determine uncollectible expense. Ms. Grace provided revised versions of both riders, which include new language linking the riders more clearly and addressing Commission oversight. NS-PGL Ex. 28.0 at 35-38; NS-PGL Exs. 28.2, 28.3.

The net write-off method is addressed in Section V.C.5, *supra*.

Commission Analysis and Conclusions

Rider UEA-GC, with the modifications proposed by the Utilities in response to Staff, is consistent with the Stipulation in Docket Nos. 09-0419/09-0420 (cons.) and Section 19-145 of the Act. Together with the proposed modifications to Rider UEA, it properly recovers incremental Account No. 904 costs. The Commission finds that the modifications proposed at Staff's suggestion more clearly link the two riders and better define the Commission's oversight. For the reasons stated in Section V.C.5, *supra*, the Commission rejects the proposed net write-off method. The Commission approves the Utilities' changes to their Rider UEA and their proposed UEA-GC, as modified in the Utilities' rebuttal testimony. The Commission directs the Utilities in their compliance filings to remove from their revenue requirements amounts that would be recovered under Rider UEA-GC.

B. Rider VBA

North Shore and Peoples Gas

The Commission approved Rider VBA, Volume Balancing Adjustment, as a four-year pilot program in the 2007 rate case, applicable to S.C. Nos. 1 and 2. Rider VBA is a symmetrical full decoupling mechanism. The Commission concluded that "a general rate case needs to be filed if Rider VBA is to become effective upon the conclusion of the pilot program." *Peoples 2007*, p. 152. In this case, the Utilities proposed to implement Rider VBA on a permanent basis, and they proposed revisions to the rider both in their direct testimony and, in response to Staff witness Ms. Ebrey, in their rebuttal testimony. Over the pilot period, Ms. Grace stated that Rider VBA operated effectively to provide customers refunds when distribution revenues (Actual Margin) per customer were greater than Commission-approved per customer levels (Rate Case Margin) and charges when Actual Margin was less than Rate Case Margin. The Utilities have each also filed two annual reconciliation statements with the Commission for which the accuracy of the calculations was not contested.[3] NS Ex. 12.0 REV at 48-50; PGL Ex. 12.0 REV at 51-53.

Ms. Grace stated that Rider VBA remains appropriate because, under the Utilities' rate design proposals, a substantial amount of fixed costs (30% for North Shore and 36% for Peoples Gas) would continue to be recovered through variable charges. This level of recovery: (1) is not aligned with the nature of the Utilities' fixed cost delivery service; (2) ensures that the Utilities either under or over recover their Commission approved revenue requirements; (3) ensures that customers will pay more or less than their share of Commission-approved distribution costs; and (4) exceeds the 20% recovery that the Commission approved for Ameren and Nicor.[4] NS Ex. 12.0 REV at 49; PGL Ex. 12.0 REV at 52.

During the pilot period, the Utilities have provided net refunds to customers. Ms. Grace explained that this means that, absent the rider, customers would have paid more than their share of the Commission-approved distribution revenues. Ms. Grace stated that, as the amounts represent net refunds over time, the Utilities benefitted from amounts that were recovered from customers when their usage and related distribution revenue were less than at Commission-approved levels. NS Ex. 12.0 REV at 50; PGL Ex. 12.0 REV at 53.

In addition to making Rider VBA permanent, the Utilities proposed to change the mechanism to an annual, rather than a monthly, adjustment. Ms. Grace explained that a monthly mechanism was intended to provide near real-time adjustments to customers. The Utilities proposed an annual adjustment to smooth out the monthly adjustments on customers' bills and to streamline the filing process. They would determine the annual Rider VBA adjustments using the same formula used for the monthly filing and substituting annual data for monthly data. The Utilities proposed a transition period to move from a monthly to an annual process. Ms. Grace stated that the Percentage of Fixed Costs would be set at 100% to reflect the Utilities' test year costs, which are all fixed. NS Ex. 12.0 REV at 49-51; PGL Ex. 12.0 REV at 52-54.

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[3] *North Shore Gas Co.,* ICC Docket No. 09-0123 (Order Feb. 10, 2010); *The Peoples Gas Light and Coke Co.,* ICC Docket No. 09-0124 (Order Feb. 10, 2010); *North Shore Gas Co., et al.,* ICC Docket Nos. 10-0237/10-0238 (Cons.) (Order Mar. 9, 2011).

[4] *In re Central Illinois Light Co., Central Illinois Public Serv. Co. and Illinois Power Co.,* ICC Docket Nos. 07-0588, 07-0589 and 07-0590 (Cons.), at 237 (Order, Sept. 24, 2008); *In re Northern Illinois Gas Company d/b/a Nicor Gas Company*, ICC Docket No. 08-0363, at 91 (Order Mar. 25, 2009).

Other Parties

[Insert]

North Shore and Peoples Gas Response

In response to Staff witness Dr. Brightwell, Ms. Grace explained that SFV rates (recovery of 100% of fixed costs through fixed charges) are a reasonable alternative for S.C. No. 1 if the Commission does not approve Rider VBA on a permanent basis. Although an SFV rate may be higher than the gas cost commodity amount on certain bills for certain low usage customers, the SFV rate would accurately reflect the fixed cost nature of the Utilities' delivery service and the gas cost commodity portion would reflect the variable market affected costs of the gas commodity. NS-PGL Ex. 28.0 at 7.

The Utilities agreed to most of Staff witness Ms. Ebrey's proposed changes to Rider VBA. Specifically, the Utilities agreed, with minor modifications to which Ms. Ebrey did not object, (1) to replace the word "margin" throughout the tariff with the word "revenue" (Staff Ex. 3.0 at 35-37), if the definitions clearly link the wording to the approved revenue requirement. NS-PGL Ex. 28.0 at 19-20; Staff Ex. 12.0 at 26; (2) to modify the annual internal audit requirements, Staff Ex. 3.0 at 42-43; NS-PGL Ex. 28.0 at 24-26; Staff Ex. 12.0 at 26; and (3) to require a compliance filing as new values to be used in the calculations are determined in a rate case proceeding. Staff Ex. 3.0 at 43; NS-PGL Ex. 28.0 at 26; NS-PGL Ex. 45.5; Staff Ex. 12.0 at 26.

The Utilities disputed Ms. Ebrey's proposal to change the calculations so that "total revenues" rather than "per customer revenues" are used to determine adjustments. Staff Ex. 3.0 at 37-42. Ms. Grace explained that the proposal is flawed because the Utilities incur costs to add new customers to their systems and the proposed customer charges, except for North Shore's S.C. No. 1, would recover less than 100% of fixed customer costs. The proposal means that additional distribution revenues received by the Utilities that would recover some of the cost to connect new customers to their systems would be refunded to customers. However, the Utilities offered an alternative that would address some of the problems posed by Ms. Ebrey's proposal. NS-PGL Ex. 28.0 at 21. For S. C. No. 1, Ms. Grace explained that Peoples Gas has proposed to recover 90% of its S.C. No. 1 fixed customer costs through the customer charge and North Shore has proposed to recover 100%. If the Commission approves these proposals, the Utilities would not oppose Ms. Ebrey's proposal for S.C. No. 1. For S.C. No. 2, the problem is substantial because the Utilities would recover lesser percentages of fixed costs through the customer charge (40% for Peoples Gas and 59% North Shore). Appropriate cost recovery for S.C. No. 2 would additionally be problematic due to the potential for customers to switch service to and from S.C. No. 2. Ms. Grace explained that, if larger S.C. No. 2 customers' usage were to increase such that they would no longer be eligible for S.C. No. 2 and transferred to S.C. No. 4 (S.C. No. 3 for North Shore), total actual S.C. No. 2 revenues would decline due to customer migration, resulting in likely charges to customers when compared to the baseline Rate Case Revenue amount for S.C. No. 2, which included the usage and related distribution charge revenue for the customers who transfer. Conversely, if larger S.C. No. 3 (North Shore) and S.C. No. 4 (Peoples Gas) customers' usage were to decrease such they would become eligible for S.C. No. 2 in a future period when they were not included in the S.C. No. 2 Rate Case Revenue amount, total actual distribution charge revenues would increase due to customer migration, likely resulting in refunds to customers and a loss in the revenue requirement for the Utilities that would be associated with migration rather than an increase in customers. To address this problem, the Utilities proposed specific wording to exclude revenues from the actual or rate case revenue calculation, as appropriate, to prevent over- or under-collection associated with customer switching. NS-PGL Ex. 28.0 at 21; NS-PGL Ex. 45.5.

In response to Ms. Ebrey's opposition to the proposal, the Utilities provided additional support by showing, in detail, how the migration and factors causing it affected Rider VBA historically, and absent the Utilities proposal, could adversely affect customers and the Utilities under Ms. Ebrey's proposal. NS-PGL Ex. 45.0 at 21-25.

In response to GCI witness Dr. Dismukes' opposition to Rider VBA, the Utilities stated that the fundamental problems with his criticisms are: Rider VBA is a full decoupling mechanism and not conditioned on the Utilities increasing their support of energy efficiency initiatives; his "lost revenue" arguments and questionable calculations are a distraction because Rider VBA is not a "lost revenue" mechanism; he and GCI witness Mr. Rubin inaccurately define "fixed costs," when, in fact, 100% of the Utilities' costs are fixed; decoupling is consistent with providing rate certainty to customers, although SFV rates would also achieve that goal; he does not dispute the Utilities' sales forecast showing declining load. NS-PGL Ex. 28.0 at 26-34; NS-PGL Ex. 45.0 at 19-23. Also, from May 2008 through August 2011, Ms. Grace stated that Peoples Gas has refunded about $22.9 million and North Shore has refunded about $4.7 million to S.C. Nos. 1 and 2 customers. NS-PGL Ex. 28.0 at 30.

Ms. Grace explained that a full decoupling mechanism is one that would compute adjustments for any changes in usage (including, for example, weather) and related distribution charge revenues per customer above and below a per customer distribution charge revenue baseline arising from the Commission- approved revenue requirement. The Commission's order did not condition approval of Rider VBA on the Utilities' energy efficiency efforts and did not reflect any special provisions for tracking usage changes or lost revenues associated with energy efficiency. NS-PGL Ex. 28.0 at 27. Ms. Grace stated that decoupling charges assure that customers appropriately pay for the service that they receive from their utility, whose fixed costs do not vary with the volume of gas that customers consume. On the other hand, decoupling credits help to supplement any savings achieved by customers. Also, as Rider VBA adjustments are applied on a per-therm of usage basis, those customers who consume less through energy efficiency efforts will pay a lesser charge amount on their reduced usage. NS-PGL Ex. 28.0 at 29-30.

Ms. Grace also noted that the Commission's approval of decoupling is consistent with national trends and making the rider permanent would reflect that dynamic. In

2007, decoupling had been approved for 17 utilities in 10 states. In 4 years, that number has grown significantly with decoupling being approved for 46 utilities in 20 states. NS-PGL Ex. 45.0 at 22.

Finally, Ms. Grace pointed out that GCI witnesses Dr. Dismukes' proposal to eliminate Rider VBA and Mr. Rubin's proposal to reduce fixed cost recovery through the customer charge and front block of the distribution charge must be considered jointly, as together they would assure that the Utilities would either over- or-under-recover the distribution revenues arising from the Commission's order in this proceeding and that customers would thus under- or over-pay. *Id*.

Commission Analysis and Conclusions

The Commission agrees with Dr. Brightwell that Rider VBA has operated as the Commission intended. The annual reconciliation proceedings have disclosed no issues with the rider's operation. The Commission also agrees with Dr. Brightwell and the Utilities that Rider VBA stabilizes the Utilities' revenues and ensures that the S.C. Nos. 1 and 2 customers neither over- nor under-pay the approved revenue requirements. While the Commission supports increased recovery of fixed costs through fixed charges, it prefers, at this time, decoupling rather than a switch to an SFV rate design -- whether the 100% fixed cost recovery proposed by the Utilities as an alternative or the 80% fixed cost recovery discussed by Dr. Brightwell and approved by the Commission for the Ameren gas utilities and Nicor Gas. We also note that the Utilities supported SFV rates as an alternative only for S.C. No. 1 while decoupling applies to S.C. No. 2 as well. Rider VBA addresses both service classifications. GCI witness Dr. Dismukes' criticisms, centered on whether decoupling has or will prompt the Utilities to spend more on energy efficiency programs, are misplaced. The Commission did not link its approval of Rider VBA to energy efficiency, nor is energy efficiency the only reason to have a decoupling mechanism. For example, weather affects customer usage and decoupling means that the customers do not overpay when weather is colder than normal or underpay when weather is warmer than normal. However, decoupling also addresses load changes, including declining load attributable to energy efficiency. Whether Rider VBA prompts the Utilities to spend more on energy efficiency than required by the Act is immaterial. The facts are that energy efficiency is occurring. The Utilities' forecast showed declining load on their systems. Section 8-104 of the Act requires them to offer energy efficiency programs to meet ever-increasing, mandated load reductions. Decoupling will take the effects of energy efficiency into account together with other factors, notably weather, that affect load variations and promote distribution rate stability for customers and the Utilities.

The Utilities proposed one significant change to Rider VBA, namely making it an annual rather than a monthly adjustment mechanism. Staff witness Ms. Ebrey proposed several other changes to Rider VBA, many of which the Utilities accepted in full or with modifications. Only one of the modifications is at issue. The Utilities disputed Ms. Ebrey's proposal to change the calculations so that "total revenues" rather than "per customer revenues" are used to determine adjustments. The Commission approves Ms. Ebrey's proposed change in the calculation and is sensitive to Ms. Ebrey's concerns about adding complexity to the rider. However, the Utilities offered a reasonable solution to a problem that could arise from Ms. Ebrey's proposal and could easily result in over- or under-recovery of the approved revenue requirements. As preventing such over- or under-recovery is the essential attribute of decoupling, the Commission supports taking reasonable steps to avoid that result, and, therefore, the Commission approves as reasonable the Utilities' proposal to implement Ms. Ebrey's change. The Commission also finds that each of the Utilities' proposals to set their percentage of fixed costs at 100% is fully supported and it is approved.

For these reasons, the Commission approves Rider VBA on a permanent basis, as modified by the Utilities and presented as an exhibit in their surrebuttal testimony.

C. Rider ICR

In connection with the introduction of new riders to implement its storage unbundling program, Peoples Gas proposed to revise Rider ICR to add Riders FST-T, SBS and P-T to the definition of Excluded Revenues. PGL Ex. 12.0 REV at 51.

1. Accumulated Deferred Income Taxes

Other Parties

[Insert]

North Shore and Peoples Gas Response

Ms. Grace stated that Mr. Effron's proposal is inconsistent with Rider ICR's design. Peoples Gas modeled Rider ICR on Commission rules applicable to water and sewer investments (83 Ill. Admin. Code Part 656). Accumulated deferred income taxes ("ADIT") are not part of those rules. NS-PGL Ex. 28.0 at 41. If ADIT is included in the rider, Mr. Stabile stated that actions must be taken to avoid violation of the normalization rules. The normalization rules are complex, and the repercussions of violating them are severe. To highlight one complexity, Mr. Stabile explained that, as a practical matter, the tax normalization rules preclude the consideration of an economic benefit related to accelerated depreciation (including bonus depreciation) in the aggregate set of estimates and projections that are used to set cost of service rates. For example, Mr. Stabile stated that, if the Rider ICR calculation considers a deferred tax liability for accelerated depreciation deductions, but does not consider the fact that the taxpayer net operating loss carry forward position has increased due to those same accelerated depreciation deductions, then the taxpayer would be in violation of the normalization requirements due to imputing an economic benefit that is greater than the utility has realized. NS-PGL Ex. 26.0 at 23-26.

Commission Analysis and Conclusions

The Commission rejects Mr. Effron's proposal to include ADIT in Rider ICR. This would be inconsistent with other, similar riders, including the water and sewer rules on which Rider ICR is modeled, and it raises potential problems involving compliance with normalization rules. The Commission approves the Utilities' proposed modifications as appropriate given our approval of the Utilities' unbundling proposal.

IX. COST OF SERVICE

A. Overview

North Shore and Peoples Gas

Only the Utilities prepared ECOSSs that they used to develop their rate design proposals. NS Ex. 13.0 at 1 and NS Exs. 13.1 - 13.8; PGL Ex. 13.0 at 1 and PGL Exs. 13.1 - 13.8.

Other Parties

[Insert]

B. Embedded Cost of Service Study

North Shore and Peoples Gas

Utilities witness Ms. Hoffman Malueg explained that 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. NS Ex. 13.0 at 7-9; PGL Ex. 13.0 at 7-9.

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. NS Ex. 13.0 at 8-25; PGL Ex. 13.0 at 8-27.

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	6.20%	8.96%
S. C. No. 2 General Service	4.75%	8.32%
S. C. No. 3 Large Volume Demand Service	7.75%	7.66%
System average	5.93%	8.72%

NS Ex. 13.0 at 33-34.

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	1.40%	8.66%
S. C. No. 2 General Service	5.89%	8.78%
S. C. No. 4 Large Volume Demand Service	6.45%	5.41%
S. C. No. 8 Compressed Natural Gas Service	3.64%	9.52%
System average	3.29%	8.49%

PGL Ex. 13.0 at 35-36.

Other Parties

[Insert]

1. Uncontested Issues

a. Sufficiency of ECOSS for Rate Design

The Utilities stated that their 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. NS Ex. 13.0 at 35; PGL Ex. 13.0 at 36. Staff reviewed the Utilities' ECOSSs and concluded that each was an acceptable guidance tool for setting rates. Staff Ex. 7.0 at 8; Staff Ex. 16.0 at 3.

Neither Staff nor any party contested the sufficiency of the Utilities' ECOSSs to develop rates in this proceeding. The Utilities' ECOSSs are complete, they systematically functionalize, classify and allocate costs, and they comport with the cost causation principles for preparing such studies that the Commission has approved in many other rate cases. The Commission finds that the Utilities' ECOSSs are sufficient and reasonable for developing rate designs in this proceeding.

2. Contested Issues

a. Classification of Uncollectible Accounts Expenses Account No. 904

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities classify Account No. 904 costs as customer-related. NS Ex. 13.0 at 8; PGL Ex. 13.0 at 8; NS-PGL 29.0 at 4. The Utilities allocate Account No. 904 costs to the customer classes using the Bad Debt allocation methodology. Ms. Hoffman Malueg explained that this methodology takes the average historical bad debt net write-offs per customer by customer class as of the 12 months ending June 30, 2010, and applies that average to the customer counts by customer class for the future test year ending December 31, 2012. NS Ex. 13.0 at 18; PGL Ex. 13.0 at 19; NS-PGL 29.0 at 4. The classification and allocation methods are appropriately based on cost-causation. Moreover, the Commission approved these methods in the Utilities' last rate cases. NS-PGL Ex. 29.0 at 2; *Peoples 2009*, p. 209.

Utilities witness Ms. Hoffman Malueg explained that cost allocation and cost recovery are distinct issues, the former falling under the ECOSSs and the latter being a rate design decision. NS-PGL Ex. 29.0 at 8. Ms. Hoffman Malueg stated that she found Mr. Rubin's terminology confusing and unclear as to whether his concerns were related to the ECOSSs or the rate design, although, in his rebuttal testimony, Mr. Rubin contends that his testimony was limited to rate design, and he made no changes to the ECOSSs. GCI Ex. 8.0 at 11.

Commission Analysis and Conclusions

The Commission concludes that Mr. Rubin's testimony about Account No. 904 costs is limited to the Utilities' rate design decisions and he has not raised issues about their classification in the ECOSSs. Rate design issues are discussed in Sec. X, *infra*. The Utilities' classification of these costs as customer related is appropriate and consistent with our decision in the Utilities' 2009 rate cases. *Peoples 2009*, p. 209.

b. <u>Classification of A&G Related to O&M</u>

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities use "Total O&M, Not Including A&G" as the classification method for A&G related to O&M expense. NS Ex. 13.0 at 19; PGL Ex. 13.0 at 20-21. Utilities witness Ms. Hoffman Malueg testified that this classification method is appropriate based on cost-causation, is recommended by the American Gas Association ("AGA") and the National Association of Regulatory Utility Commissioners ("NARUC"), and was uncontested in the Utilities' 2009 rate cases. NS-PGL Ex. 29.0 at 2, 9.

Ms. Hoffman Malueg stated that GCI witness Mr. Rubin appears to suggest that Account No. 904 costs should be excluded from the classification method for A&G related to O&M expense. GCI Ex. 3.0 at 15. She stated that it was unclear if Mr. Rubin is addressing the ECOSSs or rate design, as he contends that his testimony was limited to rate design, and he made no changes to the ECOSSs. GCI Ex. 8.0 at 11. However, she explained that A&G related to O&M Expense consists of FERC Primary Account Nos. 920-923 and 927-931, which are for expenses such as salaries, office supplies expense, and miscellaneous general expense. The Utilities incur these costs to administer their business. Uncollectibles Expense is part of their day-to-day operations and should be included in these accounts' classification method. She cited AGA's Gas Rate Fundamentals and NARUC's Gas Distribution Rate Design Manual in support of the Utilities' approach. She stated that these references specifically exclude gas costs from the classification method, but neither recommends excluding Account No. 904. NS-PGL Ex. 29.0 at 10. A classification method comprising all O&M accounts, excluding gas costs, is used because one singular activity, or O&M account, cannot be representative of the activities for which expenses are booked to the A&G accounts. The classification method encompasses all of the potential relations to activities thereby being the most representative of the activities for which expenses are booked to the A&G accounts. NS-PGL Ex. 29.0 at 11-12.

Commission Analysis and Conclusions

The Commission concludes that Mr. Rubin's testimony about A&G related to O&M expense is limited to the Utilities' rate design decisions and he has not raised issues about its classification in the ECOSSs. Rate design issues are discussed in Sec. X, *infra*. For the reasons described by Ms. Hoffman Malueg, the Utilities' use of "Total O&M, Not Including A&G" as the classification method is reasonable and is approved.

c. Classification of Fixed Costs

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities classify costs based on how they incur the costs. The three classifications are: commodity, demand, and customer. Commodity classified costs are costs that vary with the gas sold to, or transported for, customers. Demand classified costs are incurred to serve the system peak demand and do not directly vary with the number of customers and their usage; they vary with the quantity or size of plant and equipment required to service the system peak demand. Customer classified costs are incurred to extend service and attach a customer to the distribution system, meter gas usage, and maintain the customers' accounts. Typically, customer classified costs are those types of costs that vary with the number and density of customers; they do not vary with customers' consumption. Once costs are classified, changes in the customer count would not be a reason to change the classification. For example, meter costs are classified to customer. If Peoples Gas' number of customers increased from 818,000 to 835,000, that would not affect whether the classification of meter costs to customer is still appropriate. NS-PGL Ex. 29.4; NS-PGL Ex. 29.0 at 13-17.

Ms. Hoffman Malueg stated that GCI witness Mr. Rubin incorrectly concluded that the Utilities "improperly identified essentially all of their costs as being 'fixed' in nature" (GCI Ex. 3.0 at 3). While customer classified costs are sometimes referred to as "fixed costs," that does not mean they are a utility's only fixed costs. Also, while demand classified costs are classified as such based on how the costs are incurred by the peak demands placed upon a Utilities' systems, that does not mean they are not considered fixed costs. Finally, Ms. Hoffman Malueg stated that, simply because demand classified costs are allocated to service classifications using a volumetric-based allocation method, such as the Average & Peak demand allocation, does not mean the costs are not fixed in nature. NS-PGL Ex. 29.0 at 14.

Ms. Hoffman Malueg provided an example of demand classified costs, using Account 378: Measuring & Regulation Equipment, to illustrate the Utilities' position. She stated that these costs are classified to demand in the ECOSSs, because they are incurred based on peak system demand requirements. This Account is allocated to the service classifications using the Average & Peak demand allocation method, which is a volumetric-based allocation method, because each service classification's allocated share of the costs is caused by its demands placed upon the system. For example, S.C. No. 1 customers' measuring and regulating equipment would most likely be smaller in size than the S.C. No. 4 customers', because their demands are typically less than the S.C. No. 4 customers. Therefore, an allocation method that takes into account each service classification's demands is most appropriate. Yet, the costs associated with the physical assets of Measuring and Regulating Equipment are fixed in nature. Even though they have been sized to meet customers' demands, once the assets are put in place, they are essentially a fixed asset of the Utilities. Plus, once these physical assets have been put in place, their costs do not change or vary from year to year based upon customer's volumetric usage. NS-PGL Ex. 29.0 at 14.

Commission Analysis and Conclusions

Fixed costs are costs that do not vary with a customer's gas usage. The dispute in this proceeding is limited to demand classified costs, as it appears no party disagrees that commodity classified costs are not fixed and customer classified costs are fixed. Demand classified costs are costs incurred to serve customers on the system peak. Ms. Hoffman Malueg's example of measuring and regulating equipment costs aptly illustrates why demand classified costs are properly considered fixed costs. The Commission concludes that the Utilities correctly defined and classified fixed costs in their ECOSSs. How the Utilities propose to recover those costs is addressed in Section X, *infra*.

X. RATE DESIGN

A. Overview

The Utilities' proposed rate designs were intended to and would accomplish the following eight major objectives: (1) recover the Utilities' revenue requirements; (2) better align revenues with underlying costs; (3) send the proper price signals; (4) provide more equity between and within rate classes; (5) maintain rate design continuity; (6) reflect gradualism; (7) retain customers on the Utilities' systems; and (8) effectively and fairly unbundle costs and charges for standby and storage services. NS Ex. 12.0 REV at 7; PGL Ex. 12.0 REV at 7.

Other Parties

[Insert]

B. General Rate Design

1. Allocation of Rate Increase

Coupled with the Utilities' ECOSSs, the Utilities stated that the descriptions of their 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.

The Commission finds that the Utilities' ECOSSs should be used, together with the rate designs and revenue requirements we approve in this Order, to determine rates.

2. Uniform Numbering of Service Classifications

Staff witness Ms. Harden recommended that the Utilities analyze implementing uniform service classification numbering in future rate cases. Staff Ex. 7.0 at 4. The Utilities agreed to undertake this review. NS-PGL Ex. 28.0 at 6.

The Commission finds that the Utilities should analyze implementing uniform service classification numbering and, in their next rate cases, either implement uniform numbering or explain why it is not feasible.

C. Service Classification Rate Design

1. Uncontested Issues

a. North Shore Service Classification No. 2

The Record

North Shore allocated to each meter class customer-related costs based on the investment in meters and regulators and demand-related costs based on peak day demand. It proposed to recover all customer costs and a portion of non-storage related demand costs through the customer charge to minimize intra-class subsidies. The proposed customer charges for meter classes 1, 2 and 3 recover 95%, 20% and 10% of their respective non-storage related demand costs. With proposed Rider UEA-GC, the customer charge would be the same for sales and transportation customers; absent Rider UEA-GC, the sales customer charge would be higher due to recovery of gas cost related Account No. 904 costs in the customer charge. North Shore proposed to maintain the three declining block distribution charge and allocate the remaining costs to the blocks. Under North Shore's proposals, 58.6% of the S.C. No. 2 revenue requirement would be recovered through fixed charges. North Shore proposed to recover all storage related demand costs through proposed Rider SSC, Storage Service Charge. About 2.5% of fixed costs would be recovered through the rider. Thus, about 38.9% of fixed costs would continue to be recovered through volumetric distribution charges. NS Ex. 12.0 REV at 18-20; NS Ex. 12.1 at 6-7; NS Ex. 12.7. Staff witness Ms. Harden recommended approval of North Shore's proposed S.C. No. 2 rate design (Staff Ex. 7.0 at 13-16).

Commission Analysis and Conclusions

The Commission finds that North Shore's proposals are reasonable and consistent with the objectives of rate design continuity. The Commission is approving Rider UEA-GC, so the customer charges for sales and transportation customers should be the same. The Commission approves North Shore's S.C. No. 2 rate design, and North Shore should use its ECOSS and the approved revenue requirement to set rates for this class.

b. North Shore Service Classification No. 3

The Record

North Shore proposed that the S.C. No. 3 customer charge be set at cost and be the same for sales and transportation customers. The demand charge would recover 67% of non-storage related demand costs. The monthly standby service charge would be eliminated if the Commission approves proposed Rider SSC. The distribution charge would recover remaining non-storage related demand costs. NS Ex. 12.0 REV at 20; NS Ex. 12.1 at 8. Staff witness Ms. Harden recommended approval of North Shore's proposed S.C. No. 3 rate design (Staff Ex. 7.0 at 16-18).

Commission Analysis and Conclusions

The Commission finds that North Shore's proposals are reasonable and consistent with the objectives of rate design continuity. The Commission approves North Shore's S.C. No. 3 rate design, and North Shore should use its ECOSS and the approved revenue requirement to set rates for this class.

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

The Record

Peoples Gas proposed to set S.C. Nos. 4 and 8 at cost. After moving S.C. Nos. 4 and 8 to cost, it proposed to apportion the remaining revenues to be recovered from S.C. Nos. 1 and 2 using the equal percentage of embedded cost method ("EPECM"). Peoples Gas proposed, and the Commission approved, the EPECM in its last four rate cases (Docket Nos. 91-0586, 95-0032, the 2007 rate case, and the 2009 rate case). Peoples Gas testified that the EPECM provides a gradual movement toward equalizing rates of return by allocating the increase portion of the total revenue requirement on a cost of service basis. PGL Ex. 12.0 REV at 8-9; PGL Ex. 12.3.

Under Peoples Gas' proposal, S.C. No. 1 would be at 98.6% of cost. This compares with 89.9% (Docket 95-0032), 92.3% (2007 rate case) and 94.7% (2009 rate case) of cost under final rates. Peoples Gas explained that it is not applying the EPECM to all embedded costs. Under the storage unbundling proposal, it would recover storage costs from all applicable service classifications at cost. PGL Ex. 12.0 REV at 9-11. Staff witness Ms. Harden recommended approval of the EPECM (Staff Ex. 7.0 at 7-8).

Commission Analysis and Conclusions

The Commission finds that Peoples Gas' use of the EPECM continues to be an appropriate means of gradually moving S.C. Nos. 1 and 2 closer to cost of service. The Commission approves Peoples Gas' use of the EPECM and, Peoples Gas should use the EPECM together with the ECOSS, the approved rate designs and the approved revenue requirements to set rates for S.C. Nos. 1 and 2.

d. Peoples Gas Service Classification No. 2

The Record

Peoples Gas allocated to each meter class customer-related costs based on the investment in meters and regulators and demand-related costs based on peak day demand. It proposed to recover all customer costs and a portion of non-storage related demand costs through the customer charge to minimize intra-class subsidies. The proposed customer charges for meter classes 1 and 2 recover 50% and 15% of their respective non-storage related demand costs, but, in the interest of gradualism, no demand costs are recovered through the proposed meter class 3 customer charge. With proposed Rider UEA-GC, the customer charge would be the same for sales and transportation customers; absent Rider UEA-GC, the sales customer charge would be higher due to recovery of gas cost related Account No. 904 costs in the customer charge. Peoples Gas proposed to maintain the three declining block distribution charge and allocate the remaining costs to the blocks. Under Peoples Gas' proposals, 40% of the S.C. No. 2 revenue requirement would be recovered through fixed charges. Peoples Gas proposed to recover all storage related demand costs through proposed Rider SSC, Storage Service Charge. About 11% of fixed costs would be recovered through the rider. Thus, about 49% of fixed costs would continue to be recovered through volumetric distribution charges. PGL Ex. 12.0 REV at 20-21; PGL Ex. 12.1 at 6-7; PGL Ex. 12.7. Staff witness Ms. Harden recommended approval of Peoples Gas' proposed S.C. No. 2 rate design (Staff Ex. 7.0 at 13-16).

Commission Analysis and Conclusions

The Commission finds that Peoples Gas' proposals are reasonable and consistent with the objectives of rate design continuity. The Commission is approving Rider UEA-GC, so the customer charges for sales and transportation customers should be the same. The Commission approves Peoples Gas' S.C. No. 2 rate design, and Peoples Gas should use its ECOSS and the approved revenue requirement to set rates for this class.

e. Peoples Gas Service Classification No. 4

The Record

Peoples Gas proposed that the S.C. No. 4 customer charge be set at cost and be the same for sales and transportation customers. The demand charge would recover 56% of non-storage related demand costs. The monthly standby service charge would be eliminated if the Commission approves proposed Rider SSC. The distribution charge would recover remaining non-storage related demand costs. PGL Ex. 12.0 REV at 22-23; PGL Ex. 12.1 at 8. Staff witness Ms. Harden recommended approval of Peoples Gas proposed S.C. No. 4 rate design (Staff Ex. 7.0 at 16-18).

Commission Analysis and Conclusions

The Commission finds that Peoples Gas' proposals are reasonable and consistent with the objectives of rate design continuity. The Commission approves Peoples Gas' S.C. No. 4 rate design, and Peoples Gas should use its ECOSS and the approved revenue requirement to set rates for this class.

f. Peoples Gas Service Classification No. 8

The Record

Peoples Gas proposes to set S.C. No. 8 at cost. The monthly customer charge and the distribution charge would each be increased. PGL Ex. 12.0 REV at 23; PGL Ex. 12.1 at 9. Staff witness Ms. Harden recommended approval of Peoples Gas' proposed S.C. No. 8 rate design (Staff Ex. 7.0 at 19).

Commission Analysis and Conclusions

The Commission finds that Peoples Gas' proposals are reasonable and consistent with the objectives of rate design continuity. The Commission approves Peoples Gas' S.C. No. 8 rate design, and Peoples Gas should use its ECOSS and the approved revenue requirement to set rates for this class.

2. Contested Issues – North Shore and Peoples Gas

a. Service Classification No. 1

North Shore and Peoples Gas

The Utilities each proposed that its S.C. No. 1 monthly customer charges would increase and both blocks of the distribution charge would decrease. NS Ex. 12.0 REV at 11; PGL Ex. 12.0 REV at 12.

Peoples Gas proposed recovering 90% of its customer related costs, excluding gas cost related Account No. 904 costs and transportation administrative costs, through the customer charge. For North Shore, it is 100%. NS Ex. 12.0 REV at 12; PGL Ex. 12.0 REV at 14.

With proposed Rider UEA-GC, the customer charge would be the same for sales and transportation customers; absent Rider UEA-GC, the sales customer charge would be higher due to recovery of gas cost related Account No. 904 costs in the customer charge. NS Ex. 12.0 REV at 12-13, NS Ex. 12.1 at 5; PGL Ex. 12.0 REV at 14-15, PGL Ex. 12.1 at 5.

Ms. Grace stated that, in the interest of gradualism, Peoples Gas proposed setting the S.C. No. 1 customer charges below its embedded and allocated fixed costs. (Embedded costs arise from the ECOSS and allocated costs arise from applying the EPECM to embedded costs.) North Shore proposed setting the charges at embedded costs. (North Shore is proposing to set all its service classifications at cost, and, therefore, only embedded costs are relevant.) NS Ex. 12.0 REV at 13; PGL Ex. 12.0 REV at 15-16.

Ms. Grace stated that, in the interest of rate design continuity, the Utilities each proposed to recover all non-storage related demand costs through volumetric distribution rates rather than a fixed charge such as the customer charge. This results, for Peoples Gas, in only 62% of S.C. No. 1 fixed costs being recovered through fixed customer charges and, for North Shore, only 69%. The Utilities each proposed to recover all storage related demand costs through proposed Rider SSC. Ms. Grace stated that 7% (Peoples Gas) and about 2% (North Shore) of fixed costs would be recovered through the rider. Thus, Ms. Grace stated that for Peoples Gas, about 31% of fixed costs would continue to be recovered through volumetric distribution charges and for North Shore the amount is 29%. NS Ex. 12.0 REV at 13-14; PGL Ex. 12.0 REV at 16.

The front block charge (0 - 50 therms) of the declining block rate structure reflects about 65% of remaining customer, non-storage related demand and commodity costs, which is consistent with the percentage allocated in the 2009 rate case. For North Shore, it is 67%. The remainder of the S.C. No. 1 revenue requirement would be collected through an end block (over 50 therms) distribution charge. NS Ex. 12.0 REV at 14, NS Ex. 12.1 at 5; PGL Ex. 12.0 REV at 16, PGL Ex. 12.1 at 5.

Ms. Grace explained that increasing the percentage of fixed costs recovered through fixed charges is appropriate as a matter of cost causation and Commission policy. In Docket No. 95-0032 the Commission urged Peoples Gas to increase the customer charge in future rate proceedings to move it closer to cost. In the Utilities' 2007 rate case, the Commission found it appropriate that rates reflect a greater recovery of fixed costs in customer charges. In a Union Electric rate case (Docket No. 03-0009), the Commission endorsed the utility's efforts to recover all of a utility's fixed customer related costs of serving residential customers through the customer charge component of rates as well as a gradualism approach to doing so. The Commission has allowed the Ameren gas utilities and Nicor to recover, for their residential and small commercial rate classes, 80% of their fixed costs through the customer charge. Lastly, in the Utilities' 2009 rate case, the Commission stated that: "The Utilities are correct that the Commission has been increasing the proportion of fixed costs recovered through the customer charge in other proceedings. [citations omitted]. The Commission notes that the Utilities' proposal does not approach the level of fixed costs approved in those dockets. … Moreover, in the event that Rider VBA is not renewed, the slight increase proposed by the Utilities here would be a benefit in the long run." (*Peoples 2009*, p. 218). NS Ex. 12.0 REV at 15-16; PGL Ex. 12.0 REV at 17-18.

If the Commission does not permanently approve Rider VBA, Ms. Grace stated that the S.C. No. 1 customer charges would be well below their embedded fixed cost. Grace Dir., NS Ex. 12.0 REV at 15; PGL Ex. 12.0 REV at 17. With Rider VBA in place, increasing fixed cost recovery through fixed charges is sound rate design policy, but, if the Commission declines to make Rider VBA permanent, it is appropriate that SFV rates be adopted, *i.e*., recovery of 100% of fixed costs in the customer charge.

Ms. Grace explained that the Utilities consider SFV rates the most appropriate rate design to best align revenue recovery with its mostly fixed costs. An SFV rate would be equivalent to putting customers on a budget plan for the delivery service portion of their bill but without any need for a true-up. Customers would pay a fixed monthly charge and the delivery portion of their bill would be unaffected by variations in weather or other conditions. As a result, they would not over or under pay for the services that they receive. Ms. Grace explained that an SFV rate would also lower the delivery charge portion of a customer's bills during the winter period when gas usage and market commodity prices are typically at their highest. The largest portion of a small residential customer's bill, the cost of gas, would continue to send the proper signal that higher usage would result in a higher bill due to a greater consumption of gas, the price of which is largely affected by market forces. NS Ex. 12.0 REV at 16-17; PGL Ex. 12.0 REV at 18-19.

The Utilities' proposed S.C. No. 1 rate design, including making Rider VBA permanent, should be approved. If the Commission does not make Rider VBA permanent, then SFV rates are appropriate.

Other Parties

[Insert]

North Shore and Peoples Gas Response

GCI witness Mr. Rubin's principal issues concerning S.C. No. 1 rate design focus on defining fixed costs and determining how to recover those costs. Ms. Grace stated that the Utilities recognize that there are disagreements on how to allocate and recover fixed costs. Citing NARUC's Gas Distribution Rate Design Manual, she stated that the Manual confirms that demand-related costs are fixed, and that there are a few acceptable methodologies for recovering such costs. Ms. Grace stated that, absent a fixed demand charge, it is appropriate that such fixed costs be recovered through a fixed charge such as the customer charge, or spread between the customer and commodity charges. However, the Utilities have chosen to recover S.C. No. 1 demand costs through the distribution charges in a manner that the Commission previously approved. NS-PGL Ex. 28.0 at 8-9.

Ms. Grace also pointed out flaws in Mr. Rubin's analysis. For example, he did not consider the Utilities' storage unbundling proposals, which strips out storage and production demand costs as appropriate for recovery under proposed Rider SSC, and his computed demand costs per therm are overstated; and he did not consider Peoples Gas' proposed EPECM, so the demand costs per therm he calculated are further overstated. *Id*. at 9-10.

Ms. Grace testified that, contrary to Mr. Rubin's criticism, the Utilities' recovery of Account No. 904 costs through the customer charge is appropriate. It is consistent with the cost causation and classification principles discussed and the Commission order in the Utilities' 2009 rate cases and in the Uncollectible Accounts Expense rider mechanisms proceedings for the Utilities, Ameren and Nicor. The Utilities' Rider UEA-GC proposal does not suggest that collecting Account No. 904 costs on a per customer basis is improper. Ms. Grace stated that it simply applies the uncollectible accounts expense factor to the applicable bill amount, gas charge revenues. She stated that the Commission rejected recovery of Account No. 904 costs through the distribution charge when it approved recovery through the customer charge in the Utilities' 2009 rate cases. *Id*. at 10-12.

Ms. Grace also stated that Mr. Rubin's use of his reallocated A&G and O&M for rate design purposes is flawed. The reallocation ignores the Utilities' storage unbundling proposals and does not consider nor explain how his proposed reallocations, which include storage and production expenses, would affect the unbundling proposals or service classifications other than S.C. No. 1. *Id*. at 12-13.

Finally, Ms. Grace notes that Mr. Rubin's proposals do not consider the impact on other service classifications or recent Commission decisions.

Commission Analysis and Conclusions

The Commission is approving the Utilities' proposal to make Rider VBA permanent, and, therefore, does not need to consider the Utilities SFV proposal. The Utilities have properly defined the costs on their systems that are "fixed." The Commission's policy is that utilities should recover fixed costs through fixed charges, and we find that the Utilities' continued movement towards increasing the amount of fixed costs through the S.C. No. 1 customer charge is appropriate. GCI's proposals included errors that made them unreliable and GCI's general approach is inconsistent with cost causation principles. The Commission approves the Utilities' proposed S.C. No. 1 rate designs.

D. Tariffs – Other Non-Transportation Tariff Issues

1. Uncontested Issues - North Shore and Peoples Gas

a. Terms and Conditions of Service

The Utilities proposed to move, but not change, the definition of Critical Days from Rider SST to the Terms and Conditions of Service. The Utilities also proposed a new definition, Operational Flow Order ("OFO") Day, that would be included in the Terms and Conditions of Service. NS Ex. 12.0 REV at 27-28; PGL Ex. 12.0 REV at 30.

The Commission approves as reasonable the definition of the term "OFO" and it finds that proposal to move certain terms from the transportation riders to the Terms and Conditions of Service is reasonable and approves those changes.

b. Service Activation Charges

The Utilities each proposed to increase its Service Activation Charges, which recover a portion of the costs for initiating gas service. The charges apply to customers moving into or within the service territory. The Utilities perform two types of service activations, a succession turn-on for which only a meter reading is taken, and a straight turn-on for which gas has to be turned on and appliances have to be relit. The Utilities' proposed charges would collect a greater percentage of, but not all, costs from customers causing their incurrence. For Peoples Gas, the proposed charges are: $18 for a succession turn-on, $30 for a straight turn-on, and $10 charge for relighting each appliance over four. For North Shore, the proposed charges are: $20 for a succession turn-on, $42 for a straight turn-on, and $10 charge for relighting each appliance over four. NS Ex. 12.0 REV at 21-22; NS Ex. 12.9; PGL Ex. 12.0 REV at 24-25; PGL Ex. 12.9. Staff witness Ms. Harden recommended approval of the proposed charges. Staff Ex. 7.0 at 37.

The Commission finds that the Utilities' proposed charges appropriately recover a greater amount, although not all, of the costs associated with service activations. The proposed charges and movement towards full cost recovery are appropriate and are approved.

c. Service Reconnection Charges

The Utilities assess a Service Reconnection Charge to a customer whose gas has been turned off. Each customer is granted a waiver of one reconnection charge each year, except when the customer voluntarily disconnects and then requests reconnection within twelve months or when service is disconnected at the main. The Utilities analyzed the costs for: basic reconnections that only require a meter turn-on, reconnections that require setting a new meter, and reconnections that involve excavating at the main. The Utilities each proposed to increase each charge to collect a higher percentage of, but not all, the costs from the customers creating the costs. North Shore and Peoples Gas each proposed: $75 for a basic reconnection; $150 when the meter has to be reset; and $425 when service has to be reconnected at the main. The charge for relighting each appliance over four would be increased from $5 to $10, as with the Service Activation Charge. NS Ex. 12.0 REV at 22-23, NS Ex. 12.9; PGL Ex. 12.0 REV at 25-26, PGL Ex. 12.9. Staff witness Ms. Harden recommended approval of the proposed charges. Staff Ex. 7.0 at 37.

As with the service activation charges, the Commission finds that the Utilities' proposed charges appropriately recover a greater amount, although not all, of the costs associated with service activations. The proposed charges and movement towards full cost recovery are appropriate and are approved.

d. Rider 2

The Utilities proposed revising Rider 2 to add a new Storage Gas Charge, to recover gas cost related storage costs, applicable to certain transportation riders. For Riders FST and FST-T, which remain bundled services, customers would continue to pay for gas charge related storage and standby service through the Standby Demand Charge, but without the application of a Diversity Factor. NS Ex. 12.0 REV at 46-48; PGL Ex. 12.0 REV at 49-51. The Utilities proposed to simplify certain language addressing gas that they buy and sell under the transportation riders. NS Ex. 12.0 REV at 48; PGL Ex. 12.0 REV at 51.

The Commission finds that the proposed changes to Rider 2 are consistent with the Utilities' unbundling proposals and also simplify the applicable tariff language. The Commission approves the changes to Rider 2.

e. Rider 9

The Utilities proposed to add language to Rider 9 to define the charges for unauthorized use of gas service in conjunction with their transportation proposals. NS Ex. 12.0 REV at 48; PGL Ex. 12.0 REV at 51.

The Commission finds that the proposed changes to Rider 9 are consistent with the Utilities' unbundling proposals. The Commission approves the changes to Rider 9.

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. The Utilities' proposed rate designs and resulting bill impacts are consistent with the objectives of continuity and gradualism. NS Ex. 12.0 REV at 21; NS Ex. 12.8; PGL Ex. 12.0 REV at 23; PGL Ex. 12.8. Staff witness Ms. Harden concluded that the Utilities' and Staff's proposed revenue requirements would not produce undue bill impacts for the average residential ratepayers. Staff Ex. 7.0 at 23.

The Commission finds that the bill impacts of the revenue requirements it is adopting are reasonable.

XI. TRANSPORTATION ISSUES

A. Overview

The Utilities offer small volume and large volume transportation programs. North Shore's and Peoples Gas' programs are substantially identical. The large volume program is Rider FST, Full Standby Transportation Service, and Rider SST, Selected Standby Transportation Service. Alternative gas suppliers may pool customers under Rider P, Pooling Service. The large volume transportation ("LVT") program is available to North Shore's S.C. Nos. 2 and 3 customers and Peoples Gas' S.C. Nos. 2, 4 and 8 customers. The small volume program is known as Choices For You[sm] and offered under Rider CFY. Alternative gas suppliers aggregate Rider CFY customers under Rider AGG, Aggregation Service. The small volume transportation ("SVT") program is available to North Shore's S.C. Nos. 1 and 2 customers and Peoples Gas' S.C. Nos. 1, 2 and 8 customers. NS Ex. 15.0 at 3; PGL Ex. 15.0 at 3.

For the LVT program, the Commission, in the 2009 rate case order, concluded that:

> The Commission agrees that it is reasonable for the Utilities to work with Staff and all other interested stakeholders to develop reasonable proposals for unbundling storage service. The Commission finds that the Utilities should file any agreed upon proposals in their next rate cases. To the extent Staff, participating stakeholders and the Utilities do not reach agreement, the Utilities should address this matter in those rate cases.

"Unbundling," as used by the Commission in this context, refers to Rider SST, which currently links all or part of the storage service a customer receives to the customer's selection of standby service. *Peoples 2009*, p. 235. The Commission, for the SVT program, directed the Utilities to participate in workshops to address specified aspects, notably including "Allocation of and Access to Company-owned Assets," of that program. *Id*. at 253.

In response to the 2009 rate case Order, the Utilities witness Mr. Connery stated that the Utilities conducted two primary analyses modeling the capabilities of their assets -- one modeling the daily injection and withdrawal rights and another modeling the month-end storage inventory target levels. NS Ex. 14.0 at 6; PGL Ex. 14.0 at 6. Based on those analyses and adjustments made during the workshop process, the Utilities filed changes to the SVT program that took effect in March 2011. NS Ex. 14.0 at 5, 13; PGL Ex. 14.0 at 5, 12-13. Mr. Connery stated that these analyses provided the framework for addressing the Commission's directive that the Utilities develop proposals to unbundle the LVT program storage service. The unbundling proposal consists of: the replacement of Rider SST with a stand-alone storage service, called Rider SBS, Storage Banking Service; the elimination of standby service from Rider SBS; the inclusion of monthly and daily operating parameters governing the use of Rider SBS storage; and to the extent applicable, the inclusion of storage operating parameters in Rider FST, which remains a bundled service. NS Ex. 14.0 at 2-3; PGL Ex. 14.0 at 2-3.

B. <u>Uncontested Issues</u>

1. <u>Allowable Bank (AB) Calculation</u>

Each of the Utilities would determine available bank days by dividing its total storage capacity by its design peak day ("DPD"). They would not distinguish "base rate" days and "gas charge" days of bank. NS Ex. 12.0 REV at 41; NS Ex. 12.13; PGL Ex. 12.0 REV at 44; PGL Ex. 12.13.

The Commission approves each of the Utilities' use of its DPD to determine the amount of storage capacity (Allowable Bank) available to customers.

2. Rider CFY

Rider CFY customers currently pay for base rate storage costs through bundled storage costs in their service classifications. Under the unbundling proposal, they would pay for those costs through the Storage Banking Charge under proposed Rider SSC. They would pay for gas charge related storage costs through the Storage Gas Charge under Rider 2. The hub credit gas charge, which is a credit against the ABGC for Peoples Gas customers, will be billed as a separate line item. NS Ex. 12.0 REV at 40; PGL Ex. 12.0 REV at 42-43.

The Commission approves the Utilities' proposed modifications to Rider CFY as reasonable to accommodate the LVT unbundling and new Rider SSC.

3. Rider AGG (except Aggregation Charge)

Currently, the Utilities file a report for the number of days of bank for Rider AGG suppliers. The Utilities proposed to eliminate this report and, in coordination with a comparable LVT report, have the bank filing occur on April 1, to be effective May 1. NS Ex. 12.0 REV at 40-41; PGL Ex. 12.0 REV at 43.

The Commission approves the Utilities' proposed modifications to Rider AGG as reasonable to accommodate the Rider CFY changes and to simplify the number of filings.

4. Rider SBO

Rider SBO, Supplier Bill Option Service, allows SVT suppliers to issue their own bills to customers for their services and the Utilities' delivery service. The suppliers receive a credit. The Utilities proposed to increase the credit from $0.35 to $0.46 per bill per month. NS Ex. 12.0 REV at 25; NS Ex. 12.11; PGL Ex. 12.0 REV at 27; PGL Ex. 12.11.

The Commission approves the proposed increase in the Rider SBO credit. It is supported by a cost study and is uncontested.

C. Administrative Charges

North Shore and Peoples Gas

Utilities witness Mr. McKendry explained that the Utilities have a Gas Transportation Services ("GTS") department. The department's purpose is managing gas transportation-related contracts, nominations, billing and support work related to customers, their accounts and gas metering equipment. It also provides certain services, billing, and support to alternative gas suppliers participating in the SVT and LVT programs. NS Ex. 15.0 at 4; PGL Ex. 15.0 at 4. As the Utilities' tariffs show, they apply administrative charges to the contract and pool level accounts to recover the costs of activities that GTS performs. NS Ex. 12.1 at 48; PGL Ex. 12.1 at 49. Proposed Rider SBS would likewise have an Administrative Charge assessed per account. NS Ex. 12.1 at 96; PGL Ex. 12.1 at 97. An alternative gas supplier may have a pool comprised of as many as 300 customer accounts under Rider P and an unlimited amount under Rider AGG. That supplier pays a Pooling Charge (Rider P) or an Aggregation Charge (Rider AGG), consisting of a monthly charge plus a charge for each account in the pool. NS Ex. 12.1 at 71, 82; PGL Ex. 12.1 at 70, 82. NS Ex. 15.0 at 4; PGL Ex. 15.0 at 4. Rider CFY customers must be in pools, and all GTS administrative costs associated with the SVT program are assessed to suppliers and not customers. NS Ex. 12.1 at 77-78, 82; PGL Ex. 12.1 at 76-78.

As in prior rate proceedings, Mr. McKendry stated that the per account charges are based on a cost study. NS Ex. 15.0 at 2; PGL Ex. 15.0 at 2. That study identifies the three significant categories of costs (GTS labor, GTS other (*i.e.*, non-labor), and IT (Information Technology)). The costs in those categories are allocated to Rider FST (not pooled), Rider SST/SBS (not pooled), Rider P, and Rider AGG. Additionally, the study includes credits for LVT program imbalance trade charges, SVT billing service (called the "LDC Billing Option"), and the "per pool" administrative charge. (The Utilities explained that the supplier pays an administrative charge that is a fixed amount per month per pool ($200) plus a per account charge. The purpose of the cost study is to develop the per account charges, so the fixed pool charge is backed out through a credit.) Importantly, Mr. McKendry stated that the study includes only costs that directly support the transportation programs. Thus, for any planned activity by GTS that is not transportation-related work, the study removes those costs. As examples, these activities would include work for customer accounts that are not currently active on one of the transportation programs. Most often this would occur when a transportation customer has additional accounts that are not on a transportation program or when GTS performs complex billing transactions, such as special metering and instruments or special billing, for non-transportation customers. NS Ex. 15.0 at 5; NS Ex. 15.1; PGL Ex. 15.0 at 5; PGL Ex. 15.1. Also addressing the fact that some GTS work does not support transportation services, the cost study assumes 15 GTS employees (McKendry Tr. 09/01/11 at 673) even though the department has 17 employees (NS Ex. 15.0 at 3; PGL Ex. 15.0 at 3).

Other Parties

[Insert]

North Shore and Peoples Gas Response

Utilities witness Mr. McKendry stated that Staff witness Mr. Sackett's proposed downward adjustments based on what he considered over-budgeting (Staff Ex. 9.0 at 7) should be rejected. Mr. McKendry stated that the budget used to develop the test year costs is based upon the best available information at the time regarding future enrollment and GTS and IT costs required in support of the programs. If historical budgets exceeded actual costs in the three years that Mr. Sackett reviewed, this does not mean the budget process is flawed. Many variables, especially unanticipated events, affect actual costs. For example, Mr. McKendry explained that, in two of the three years that Mr. Sackett reviewed (2008 and 2009), the Utilities were in the midst of merger-related activity. While the budget included two additional positions for GTS, a hiring freeze occurred and those two positions were never filled. In 2008, three employees retired and one more moved into another position within the company. Later, GTS replaced a few of those experienced employees with newer employees. Changes in the level of program participation is another external variable for which GTS attempts to plan. Supplier marketing efforts, a factor outside the Utilities' control, also affect enrollment. NS-PGL Ex. 31.0 at 3. Also, Mr. McKendry stated that the proposed administration charges, except for Peoples Gas' Rider P per account charge, are lower than the current charges. In fact, the test year forecast is significantly (8%) lower than the actual 2010 costs. NS-PGL Ex. 31.0 at 3; NS-PGL Ex. 31.1.

Mr. McKendry testified that Mr. Sackett's approach of reducing the test year budget by calculating a factor by which cost categories in prior years' budgets exceeded actual costs (Staff Ex. 9.0 at 7-8; Staff Ex. 18.0 at 4-5) assumes that unexpected events that caused costs to be lower than forecast would occur again. For example, to the extent an unplanned and unexpected merger-related reduction in projected and actual employee count caused past actual results to differ from the past budgets, applying a factor to reduce the 2012 budget because of the impact of that past event, in effect, assumes a reduction in employee count that is not projected to occur. NS-PGL Ex. 47.0 at 3. Mr. Sackett has not identified specific flaws with the current budget (*e.g.*, he presented no evidence that the GTS employee complement is over-stated or that events such as a merger were expected to affect the GTS budget). Instead, Mr. McKendry explained, his recommended reduction is based on applying a factor derived from recent years' data, which, given the specific sorts of events identified by the Utilities as affecting those years' data (notably the merger), is not a reasonable approach.

Commission Analysis and Conclusions

The Commission finds that the cost study on which the Utilities based their various administrative charges is reasonable. It properly excludes costs associated with services for sales customers and divides costs between North Shore and Peoples Gas and among the different programs. While Staff showed that recent years' budgets have been higher than actual costs for those years, the Utilities demonstrated that significant unexpected events, notably their merger, affected those years. There is no evidence that an event of that magnitude and with that expected impact on the GTS costs is likely to occur during the test year. The Commission approves the Utilities' proposed administrative charges.

IGS witness Mr. Parisi argues that the SVT administrative charges be assessed to all customers eligible for the program. This recommendation is addressed in Section XI.E.1, *infra*.

D. Large Volume Transportation Program

1. Administrative Charges

Staff witness Mr. Sackett recommended a reduction in the forecast costs underlying the administrative charges applicable to the LVT and SVT programs. This recommendation is addressed in Section XI.C, *supra*.

2. Transportation Storage – Issues

North Shore and Peoples Gas

In its 2009 rate case order, the Commission directed "the Utilities to work with Staff and all other interested stakeholders to develop reasonable proposals for unbundling storage service." The Utilities proposed Rider SBS to meet this directive and allow LVT customers to select the amount of storage service they wish to receive. The Utilities stated that the analysis that supported this rider prompted changes to Rider FST and corresponding changes to Rider P, the pooling service applicable to these riders. Proposed Rider SSC is the cost recovery mechanism that ensures that customers pay only for the storage that they receive. The Utilities proposed to implement these changes on August 1, 2012, thus allowing the Utilities, customers and suppliers a transition period to prepare for the new programs; accordingly, the Utilities have also proposed transition riders for existing services to provide a bridge to the new services. Utilities witness Mr. Connery stated that the Utilities' proposals fairly allocate available storage-related assets to all customers who use those assets, namely sales customers, SVT customers and their suppliers, and LVT customers and their suppliers. Mr. Connery stated that the proposals accomplish the unbundling sought by the Commission and align the LVT programs with the changes to the SVT programs that the Commission required. By unbundling storage service, the Commission meant proposals to allow Rider SST customers to receive storage service not tied to standby service. *Peoples 2009*, p. 235. Ms. Grace explained that, currently, all or part of the storage capacity (called "Allowable Bank" or "AB") that a Rider SST customer receives may be based on its election of standby service. Rider SST customers served under the Utilities' S.C. No. 2 and Peoples Gas' S.C. No. 8 (where storage costs are currently bundled in rates for both rate classes) receive the full amount of base rate storage bank even if they choose zero standby service. If an S.C. No. 2 customer or Peoples Gas S.C. No. 8 customer takes Rider SST service, that customer's selection of standby service will provide for additional storage capacity in the form of gas charge days. The storage capacity that an S.C. No. 3 (North Shore) or 4 (Peoples Gas) receives is wholly determined by the amount of standby service the customer selects. NS-PGL Ex. 28.0 at 16; *also see* NS 12.1 at 55; PGL Ex. 12.1 at 56. Mr. Connery stated that standby service allows an LVT customer to buy gas from the Utilities up to an amount that the customer selects. If the customer's own gas deliveries, including what it may take from storage, are insufficient to meet its requirements, it would buy the difference from the Utilities up to its standby rights. The customer does not nominate the amount of standby gas it wants to buy; the purchase happens automatically as an after-the-fact part of the order of deliveries to the customer. In other words, it is a "no-notice" service. NS Ex. 14.0 at 21; PGL Ex. 14.0 at 21.

Mr. Connery explained that, in response to the Commission's requirement that they change the allocation of and access to storage rights for the SVT program, the Utilities analyzed their gas supply-related assets that support storage services. He said that the SVT changes and, more importantly, the analyses underlying those changes, provided much of the framework for the proposed changes to the LVT programs. Many of the SVT storage-related terms and conditions translate directly to the large volume program. NS Ex. 14.0 at 7; PGL Ex. 14.0 at 7. This is because the storage asset pool for the LVT program is, like that for the SVT program, the aggregation of all the Utilities' storage-related assets. The model developing access to and the equitable allocation of storage applies to all customer classes, including the LVT customers. NS Ex. 14.0 at 22; PGL Ex. 14.0 at 21-22.

From this analysis, the Utilities developed an unbundling proposal that includes: (1) a stand-alone storage service (Rider SBS) under which customers select the amount of storage capacity that they wish; (2) monthly inventory targets (minimum and maximum) for all months with monthly cashouts to the extent a customer falls outside the ranges; (3) daily injection and withdrawal limits, with appropriate distinctions for Critical Days and OFO Days, with daily cashouts to the extent a customer falls outside the ranges; (4) a daily tolerance around the daily ranges as part of the transition to the new service; and (5) elimination of the no-notice standby service because it requires the storage assets that are fully allocated to the storage service. NS Ex. 14.0 at 18-19; PGL Ex. 14.0 at 18.

Mr. Connery stated that Rider SBS, like Rider SST, would be a daily measurement service. Customers would continue to be able to transfer their contracts to a supplier to manage in a pool, and the pool supplier would be able to aggregate many contracts' ABs to take advantage of possible diversity within the pool to stay within monthly and daily requirements. Existing nomination flexibility and AB trading rights remain intact. NS Ex. 14.0 at 19; PGL Ex. 14.0 at 18-19.

While the Utilities derived the Rider SBS terms and conditions from their analysis of underlying assets, Mr. Connery stated that those terms and conditions are substantially more generous than the tariff and operational limitations of those assets. NS Ex. 14.4; PGL Ex. 14.4.

The Utilities' thorough analysis for their SVT program and how they applied it to the LVT program is addressed at length in Utilities witness Mr. Connery's direct testimony and exhibits. In summary, each of the Utilities reviewed its purchased storage, company-owned storage (Peoples Gas only), transportation, and peaking (*e.g.*, liquid propane ("LP") gasification for North Shore and Liquefied Natural Gas gasification ("LNG") for Peoples Gas) assets to determine which are storage-related. The Utilities determined that all purchased storage services (and, for Peoples Gas, its company-owned field, Manlove Field), all peaking assets, and some storage-related transportation assets (*i.e.*, transportation capacity needed to deliver gas to storage for injections or deliver storage withdrawals to the citygate) are storage-related. Each of the Utilities used its Design Peak Day Supply portfolio ("DPDS") as a guide for this analysis (*see* NS Ex. 14.1; PGL Ex. 14.1) to ensure that all parties receive a fair allocation of storage deliverability on a peak day and that all of the storage attributes and capabilities (*e.g.*, capacity, daily balancing and peaking) are fairly allocated based on a peak day allocation methodology. The DPDS is the collection of resources available on a DPD to serve customers. NS Ex. 14.0 at 7-8; PGL Ex. 14.0 at 7-8.

Mr. Connery stated that the analysis included all storage assets and considered them in the aggregate. This is appropriate even though each storage asset has unique operating capabilities and requirements, generally including daily injection and withdrawal capabilities, peaking capability, and operating guidelines and tariff parameters, that must be followed. The Utilities use the storage assets in aggregate to meet daily balancing needs and varying seasonal peak sendout expectations. Mr. Connery stated that the storage assets' ability to complement each other in meeting system demands is influenced by dispatch order. For example, Peoples Gas' Manlove Field delivers significant early winter peaking capability and the pipeline storage assets provide coverage of the late winter peaking needs, as the Manlove Field peaking capability diminishes. On a daily basis, the Utilities reserve some no-notice pipeline storage balancing capabilities to accommodate changes to sendout and transportation program deliveries subsequent to pipeline nomination deadlines. Extreme intraday changes and larger changes that occur over weekends and holidays are addressed with variations to the Manlove Field dispatch plans. (North Shore does not own a storage field. However, it purchases a storage service from Peoples Gas that is supported by Peoples Gas' Manlove Field and the operational features of that field affect North Shore's service. NS Ex. 14.0 at 9.) The timing of the dispatch of the set-aside asset capabilities is critical in determining the daily storage injection and withdrawal rights available to the transportation programs. Similarly, Mr. Connery stated that the peaking capability of Manlove Field, LNG (Peoples Gas), and the LP facility (North Shore) is designed to meet a very limited number of extreme sendout days and is not available to meet normal daily swing needs. As such, the daily swing and peaking capabilities of the individual elements of the storage portfolios cannot simply be tallied up to determine an appropriate level of daily injection and withdrawal rights available to the transportation programs. Rather, those rights need to be determined considering how the specific contribution and dispatch timing of the storage assets function in aggregate to meet system demands. NS Ex. 14.0 at 8-10; PGL Ex. 14.0 at 8-10.

Mr. Connery stated that the parameters, such as month-end storage inventory target levels and daily injection and withdrawal rates, developed from this analysis, which supported the SVT program changes that are already in effect, apply directly to the LVT program. NS Ex. 14.0 at 22; PGL Ex. 14.0 at 22.

Mr. Connery stated that the daily delivery ranges developed for the SVT program do not have a Rider SST parallel because that concept applies to non-daily read customers. Rider SST customers must have a daily demand measurement device, and Rider SBS customers would likewise have such a device. However, using the daily injection and withdrawal rate schedule from the SVT program represents an equitable allocation of access to storage for Rider SBS. NS Ex. 14.0 at 22-23; PGL Ex. 14.0 at 22-23. To ease the transition to the new daily rights and obligations, the Utilities proposed a Daily Balancing Tolerance band about the daily injection and withdrawal rights to provide additional storage injection and withdrawal flexibility under Rider SBS. NS Ex. 14.0 at 26-27; NS Ex. 14.6; PGL Ex. 14.0 at 25-27; PGL Ex. 14.6.

Rider SBS would not include a standby service. Mr. Connery explained that the assets needed to support this service are fully allocated and available to the unbundled storage service. NS Ex. 14.0 at 25; PGL Ex. 14.0 at 24-25.

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities stated that the principal criticisms of their proposals are that the Utilities have not demonstrated a need (*e.g.*, compromised system integrity or economic harm to sales customers) to change the LVT programs beyond simply making storage available without a link to standby service. The fundamental flaw with those criticisms is that Staff and intervenors would perpetuate inter-class subsidies resulting from all classes of customers (sales, SVT and LVT) relying on the same storage assets but receiving different access rights.

In response to Staff witness Mr. Sackett, Mr. Connery stated that the Utilities did not try to quantify whether “net” economic harm occurs to sales customers. However, the Utilities oppose a rate design concept premised on net activity by one group of customers (LVT customers in this case) over some undefined period potentially being neutral or beneficial to other groups of customers (in this case, sales customers). Specifically, they oppose the transportation customers having the latitude to operate with wide discretion (altering or not altering deliveries for any reason(s)), to which the sales customers’ purchases are altered to compensate, potentially economically harming the sales customers, and for which they may be compensated by some potential future opportunity -- again provided at the transportation customers’ discretion -- and to which such opportunity the sales customers are to react. NS-PGL Ex. 46.0 at 4.

Moreover, in response to Mr. Gorman, the Utilities showed that under the current tariff parameters the sales customers' purchases are modified extensively to manage day over day changes in sendout. For example, in aggregate for the period January 2008 to March 2011, the large and small volume transportation programs' deliveries did not vary in anticipation of usage variations. After using storage swing availability, very large adjustments to the purchases for sales customers were required. The Utilities showed, graphically and statistically, the large fluctuations in sales purchases necessary to meet sendout and the unresponsiveness of the transportation program deliveries to that sendout. The ability of the transportation customers to not vary deliveries with sendout results from the current LVT tariffs' ineffectiveness in limiting transportation program use of sales customer's equitable share of daily injection and withdrawal rights. NS-PGL Ex. 46.0 at 11-13. Forcing sales customers to bear the burden of day-to-day balancing when transportation customers have the latitude to choose to not respond to sendout changes is unfair to sales customers. It is particularly inappropriate since many transporters' load patterns are comparable to sales customers', *i.e*., they use gas at a similar load factor and ought to use storage similarly. NS-PGL Ex. 30.0 at 8.

Mr. Connery explained that, based on a request received during the LVT collaborative process, the Utilities expanded the width of the month-end ranges (*i.e*., the difference between the high and low balance targets). The Utilities based the range expansion on updated model parameters and diversity considerations. NS Ex. 14.0 at 23; NS Ex. 14.5; PGL Ex. 14.0 at 23; PGL Ex. 14.5. In addition, in response to CNE witness Mr. Kawczynski's testimony, the Utilities agreed to offer "super pooling" for the monthly target levels, to be implemented twelve months after the Commission issues its final Order in this proceeding. Mr. McKendry explained that super pooling is the aggregation of a supplier's contracts for purposes of determining if certain tariff requirements are met. NS-PGL Ex. 31.0 at 6. The Utilities proposed that this super pooling would be similar to the service in place for the current November end of month storage balance requirement. Each supplier participating in pooling service would have a super pool for Riders FST and SBS and separate super pools for Peoples Gas and North Shore. NS-PGL Ex. 47.0 at 4.

Reflecting the substantial flexibility under their proposals, the Utilities explained that the proposals allow for 100% cycling of storage; at the other extreme, the proposal imposes no cycling requirement for North Shore and only 32% cycling for Peoples Gas. In other words, there are months when a transportation customer may have a storage balance at 0% of capacity and other months when the balance may be 100% of capacity; at no time can the Utilities have aggregate storage balances at those extremes, *i.e*., the proposed rights exceed the capabilities of the underlying assets. NS-PGL Ex. 30.0 at 12, 15. This fully meets IIEC/CNE witness Mr. Gorman's stated benefit of storage providing a physical hedge. IIEC/CNE Ex. 1.0 at 12. As another example, on a peak day, a transportation customer can meet a substantial portion of its usage (75% of its MDQ for Peoples Gas and 64% of its MDQ for North Shore) from storage. NS-PGL Ex. 30.0 at 11. This flexibility contrasts sharply with Mr. Gorman's comment that storage has "virtually no value" under the Utilities proposal. IIEC/CNE Ex. 1.0 at 17.

In response to Staff and intervenors, the Utilities agreed to use an average daily price (*i.e.*, the Midpoint) as the basis of the daily cashout charge rather that the proposed Daily Index Common High and Daily Index Common Low. NS-PGL Ex. 46.0 at 10-11.

Commission Analysis and Conclusions

The Commission finds that the Utilities' approach to developing an unbundling proposal for their LVT programs, namely, use of the modeling developed to revise their SVT program, is reasonable. It is uncontested that the same assets support the storage service to LVT customers as supports services to SVT and sales customers. The rights and obligations of that storage should be equitably distributed to the different customer classes. The fact that customers may use or want to use storage differently does not change the capabilities of the assets supporting the service. The Utilities have properly considered the assets in the aggregate, as the service they provide is based on the combined capabilities of the assets. It is also appropriate that the Utilities are offering more expansive rights than the physical or contractual limits on the assets would support because all parties recognize that there is diversity among customers. Finally, the availability of super pooling for the monthly storage requirements further accommodates diversity, and the Commission orders the Utilities to make super pooling available, for the monthly requirements, 12 months after their new tariffs become effective.

No party requested that the Utilities continue to offer standby service, other than as part of the bundled service (Rider FST) that is still available and the Commission therefore approves the elimination of standby service from the unbundled rider.

The Commission agrees with Staff and intervenors that the daily cashout pricing should be based on an average price and not the published high or low price. If the Utilities believe that different pricing is needed to create proper incentives, then they may file and support such a proposal in another proceeding.

The Commission approves the Utilities' unbundling proposal, including the elimination of standby service, the changes to storage availability on a monthly and daily basis, the availability of super pooling for monthly requirements, and the change to the daily cashout pricing. The proposal addresses the Commission's unbundling directive from the 2009 rate case and properly aligns the service with the SVT program and with the assets that support the Utilities' service to their sales customers.

3. Associated Rider Modifications

a. Rider SBS/SST

Rider SBS sets forth the specific storage rights and obligations necessary to implement the proposal described in Section XI.D.2, *supra*. Rider SST, as described in Section XI.D.3.e, *infra*, would take the form of a transition rider and remain in effect only through July 31, 2012.

Ms. Grace explained that Rider SBS sets forth in detail the terms and conditions of the service, particularly the proposed daily and monthly storage requirements and the storage subscription process. Compared with Rider SST, which it replaces, the Rider SBS proposal required new definitions and rates, and the elimination of standby service requires changes. NS Ex. 12.0 REV at 31-34; PGL Ex. 12.0 REV at 33-37.

The Utilities stated that customers would receive AB days with no distinction between base rate and gas charge days. Available bank days would be determined by dividing total storage capacity by its DPD. Rider SBS customers would select their storage quantity and other customers (sales, SVT, and Rider FST) would receive the full number of available days. Rider SBS customers would select from one day of storage up to the maximum amount of days, in full day increments, and, if it is not fully subscribed, may request additional capacity. Sales customers would use any unsubscribed capacity. NS Ex. 12.0 REV at 32; PGL Ex. 12.0 REV at 34-35; NS Ex. 15.0 at 6-8; PGL Ex. 15.0 at 6-8.

Riders SST/SBS include a cost-based charge for the daily demand measurement device, which would continue to be required for customers taking service under these riders. NS Ex. 12.0 at 25; NS Ex. 12.10; PGL Ex. 12.0 at 27; PGL Ex. 12.10.

Other Parties

[Insert]

North Shore and Peoples Gas Response

See Section XI.D.2, *supra*.

Commission Analysis and Conclusions

As stated above, the Commission approves the Utilities' unbundling proposal and, therefore, approves, Rider SBS. However, the Utilities must modify the rider to include super pooling and the change to the daily cashout pricing.

b. <u>Rider FST</u>

North Shore and Peoples Gas

Rider FST sets forth the specific storage rights and obligations necessary to implement the unbundling proposal. Mr. Connery explained that Rider FST would continue to be a bundled service, *i.e*., would still include standby service and a full complement of AB days, and those customers would receive the standby service they have today, with limited exceptions. The exceptions being that customers must deliver some gas on OFO and Critical Supply Shortage Days (39% (North Shore) and 27% (Peoples Gas) of the customer's MDQ). The limit results from the analyses defining access to the capabilities of storage assets that reflects the storages capabilities relative to the overall company portfolio and equitably allocating those capabilities to that group. The delivery requirement represents the non-storage component of the design day portfolio. NS Ex. 14.0 at 25, 31; NS Ex. 14.1; PGL Ex. 14.0 at 25, 31; PGL Ex. 14.1.

Ms. Grace described the tariff changes to effectuate the proposal. NS Ex. 12.0 REV at 36-37; PGL Ex. 12.0 REV at 39-40.

Other Parties

[Insert]

North Shore and Peoples Gas Response

Recognizing that the delivery requirement on certain days is new and this means that standby gas will not be available at the generally applicable price diminishes the service, the Utilities propose to reduce the charge for reserving standby service. Mr. Connery stated that standby availability is expected to exceed 95%, but given the introductory nature of the delivery obligation, the Utilities proposed to apply a 20% discount to the firm transportation costs in calculating the Demand Gas Charge. NS-PGL Ex. 46.0 at 10.

As to other Rider FST proposals, the Utilities stated that the changes are fully supported by the modeling that underlies the current SVT program and proposed Rider SBS. Just as it is appropriate to remove subsidies from sales customers to transportation customers, it is important that the different LVT riders operate under the same equitable access to storage parameters.

Commission Analysis and Conclusions

As stated above, the Commission approves the Utilities' unbundling proposal and, therefore, approves, Rider FST, with the modification to the charge that the Utilities proposed in surrebuttal. The Utilities must modify Rider 2 to address their proposed discount to the Demand Gas Charge.

c. Rider P

North Shore and Peoples Gas

The Utilities stated that Rider P is available to suppliers who deliver gas to the Utilities' LVT customers. The Utilities proposed to revise Rider P to address changes to Rider FST and proposed Rider SBS. The changes align the terminology, parameters and the operations of the rider with Riders FST and SBS and remove language which no longer applies. NS Ex. 12.0 REV at 38-39; PGL Ex. 12.0 REV at 41.

Other Parties

[Insert]

North Shore and Peoples Gas Response

See Section XI.D.2, *supra*.

Commission Analysis and Conclusions

As stated above, the Commission approves the Utilities' unbundling proposal and, therefore, approves, Rider P. However, the Utilities must modify the rider as needed to be consistent with changes we are requiring to the unbundling proposal.

d. Rider SSC

North Shore and Peoples Gas

The Utilities each proposed Rider SSC, Storage Service Charge, to accommodate their storage unbundling proposals. Storage costs are stripped out of the revenue requirement so that such costs are recovered separately. Initial charges would be set when proposed rates take effect. The Utilities would determine subsequent charges in an annual filing. NS Ex. 12.0 REV at 42-43; PGL Ex. 12.0 REV at 45-46.

Ms. Grace explained that Rider SSC sets a Storage Banking Charge for transportation customers and a Storage Service Charge for sales customers. The Storage Banking Charge applies to transportation customers on each therm of AB or MSQ storage capacity, and the Storage Service Charge applies to sales customers on each therm of delivered gas. NS Ex. 12.0 REV at 43-44; PGL Ex. 12.0 REV at 46-47.

Ms. Grace stated that the Storage Banking Charge recovers the production and storage related revenue requirements, excluding the carrying cost of investment in top gas storage. The initial Storage Service Charge would be determined at currently subscribed transportation storage levels. If transportation customers subscribe for capacity in excess of the currently subscribed levels, the charge to sales customers would decrease, and *vice versa*. As the carrying cost of top gas in storage is not included in the Storage Banking Charge, a separately billed storage credit is not necessary as it is currently provided. NS Ex. 12.0 REV at 44; PGL Ex. 12.0 REV at 47-48.

Other Parties

[Insert]

North Shore and Peoples Gas Response

In response to intervenors, Ms. Grace explained that proposed Rider SSC provides for cost recovery of on-system storage costs and ensures cost recovery for unsubscribed storage. In other words, Rider SSC is only the storage cost recovery component of the Utilities' unbundling proposal. It is not the Utilities' overall unbundling proposal. The intervenors' criticisms about the unbundling proposal did not pertain to the cost recovery mechanism. NS-PGL Ex. 28.0 at 17.

Commission Analysis and Conclusions

The Commission approves the Utilities' proposal to unbundle standby and storage services and therefore, approves, Rider SSC to recover unbundled storage costs which are part of the Utilities revenue requirement. No other party has made a proposal to recover such costs. As demonstrated by the Utilities and agreed to by Staff, the rider properly recovers the cost of storage from the different customers that use that storage.

e. <u>Transition Riders</u>

The Utilities proposed that Rider SBS be effective on August 1, 2012, to allow Rider SST customers time to transition from their current service to Rider SBS. This would also allow the Utilities time to develop and implement the technical programming that would be needed to integrate the new service into the their nomination and billing systems. This implementation date would provide additional time to fully develop the appropriate supporting processes and to effectively educate customers, suppliers and employees about the new service. NS Ex. 12.0 REV at 34-35; PGL Ex. 12.0 REV at 37-38.

Rider SST would remain in effect until Rider SBS becomes effective. Until then, the rider would operate as it does today with a few exceptions and clarifications that Utilities witness Ms. Grace described in detail and that are set forth in proposed Rider SST. NS Ex. 12.0 REV at 35-36; PGL Ex. 12.0 REV at 38-39.

The revised Rider FST would take effect August 1, 2012, and, until then, a transition rider, Rider FST-T would be in effect. Proposed Rider FST-T would be similar to current Rider FST but with a few exceptions similar to the transitional version of Rider SST. NS Ex. 12.0 REV at 37-38; PGL Ex. 12.0 REV at 40-41.

Rider P-T provides interim pooling service for suppliers who deliver gas to Riders SST and FST-T customers, until both terminate on July 31, 2012. Language in Rider P-T has also been revised to align it with the changes proposed for Riders SST and FST-T. NS Ex. 12.0 REV at 39; PGL Ex. 12.0 REV at 42.

The Utilities stated that the transition riders are necessary to effectuate a smooth transition to the new services. Even if the Commission does not adopt the Utilities' proposal in full, a transition period is appropriate and consistent with how the Utilities have previously implemented changes to their LVT program. *See e.g.*, *Peoples 2009*, p. 231.

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Staff's and intervenors' issues with the unbundling proposal did not include specific proposed changes to the transition riders.

Commission Analysis and Conclusions

As stated above, the Commission approves the Utilities' unbundling proposal and, therefore, approves, the transition riders. For the reasons stated by the Utilities, it makes sense to delay the implementation of the new programs and allow all affected parties time to prepare for their implementation.

E. Small Volume Transportation Program (Choices for You[SM] or "CFY")

1. Aggregation Charge

North Shore and Peoples Gas

The Rider AGG Aggregation Charge is a monthly charge ($200 per pool) plus a charge for each account in the pool. The Rider AGG Aggregation Charge applies to alternative gas suppliers and not customers. NS Ex. 12.1 at 82; PGL Ex. 12.1 at 82. Utilities witness Ms. Grace explained that this is consistent with cost causation principles. It is clear that GTS' current services and the proposed new storage subscription process have been and would be provided to transportation customers and suppliers. Accordingly, it is clear who is causing the costs that have been or would be incurred. For these reasons, the Utilities proposed that the administrative charges for their Riders AGG, FST, FST-T, SST, and P continue to be assessed to transportation customers and suppliers who take service under the transportation riders. NS Ex. 12.0 REV at 24; PGL Ex. 12.0 REV at 26-27.

Other Parties

[Insert]

North Shore and Peoples Gas Response

The Utilities stated that IGS witness Mr. Parisi's proposal to allocate SVT administrative costs to all eligible customers should be rejected, and his contention that the Utilities are improperly recovering certain costs from SVT suppliers is incorrect.

The Utilities stated that the costs underlying the SVT program are specifically associated with providing services to the suppliers and customers who participate in that program. As sales customers do not cause the costs that are incurred by the GTS department and related IT costs, they should not be assessed any of the costs. NS-PGL Ex. 28.0 at 41. Ms. Grace stated that Mr. Parisi's attempt to compare the Utilities' call center costs, recovered from all customers, with GTS costs recovered from SVT suppliers (IGS Ex. 1.0 at 34) is flawed. She stated that sales customers do not call GTS for service and do not pay GTS costs. Suppliers do call GTS (*see* IGS Ex. 1.0 at 35), and suppliers pay the costs associated with the services that GTS provides to suppliers. In contrast, both sales customers and transportation customers may call the call center, which serves all customers. Cost causation principles properly result in GTS costs associated with the SVT program being recovered from SVT suppliers and costs such as Call Center costs being recovered from all customers who may use that service. NS-PGL Ex. 28.0 at 41. Sales customers pay these administrative costs for the services they receive through their service classification base rate charges. Suppliers are not customers under a service classification and, thus, do not pay the administrative costs for the types of services they do not receive.

Ms. Grace also stated that IGS witness Mr. Parisi is incorrect that SVT customers are paying twice for certain costs. Although SVT customers buy their gas from alternative suppliers, the Utilities continue to provide delivery service and storage and balancing services so that the transportation programs can exist. As examples, Ms. Grace cited functions associated with initiating service to a customer (such as the credit review related to deposit requirements) and terminating service, which apply to all customers; credit reporting applies to all customers because customers owe the Utilities for delivery service charges and those amounts may become uncollectible expenses; and gas supply personnel provide support for securing and managing the services and assets that underlie storage and balancing services. NS-PGL Ex. 28.0 at 42.

Commission Analysis and Conclusions

The Commission agrees with that the Utilities' proposal to continue to recover administrative costs associated with their GTS department and certain transportation-related IT functions from transportation customers and suppliers is supported by cost causation principles and does not result in double recovery of costs from these classes of customers. Indeed, suppliers, who are responsible for the SVT program's

Aggregation Charge, pay no administrative costs under the Utilities' service classifications. The Commission approves the Utilities' proposed aggregation charge applicable to the SVT suppliers.

2. Purchase of Receivables (withdrawn)

The Record

IGS witness Mr. Parisi recommended that the Utilities implement a purchase of receivables program. Parisi Dir., IGS Ex. 1.0 at 6-30. The Utilities opposed the proposal. NS-PGL Ex. 17.0 at 22-25; NS-PGL Ex. 31.0 at 4-6. Staff witness Dr. Rearden opposed the proposal. Staff Ex. 19.0 at 2-3. Mr. Parisi withdrew his proposal. IGS Ex. 2.0 at 4-14.

Commission Analysis and Conclusions

The proposal has been withdrawn and there is no issue for the Commission to decide.

XII. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) Peoples Gas is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the Act;

(2) North Shore is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the Act;

(3) the Commission has jurisdiction over the parties and the subject matter herein;

(4) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; the Appendices attached hereto provide supporting calculations;

(5) the test year for the determination of the rates herein is found to be just and reasonable should be the 12 months ending December 31, 2012; such test year is appropriate for purposes of this proceeding;

(6) the $411,643,000 original cost of plant for North Shore at December 31, 2009, and the $2,667,949,000 original cost of plant for Peoples Gas at

December 31, 2009, reflected on each Utility's Schedule B-5, Page 1 of 2, are unconditionally approved as the original costs of plant;

(7) for the test year ending December 31, 2012, and for the purposes of this proceeding, Peoples Gas' original cost rate base with adjustments is $1,472,853,000.

(8) for the test year ending December 31, 2012, and for the purposes of this proceeding, North Shore's original cost rate base with adjustments is $192,652,000;

(9) a just and reasonable return which Peoples Gas should be allowed to earn on its net original cost rate base is 8.11%; this rate of return incorporates a return on common equity of 10.85% and costs of long-term debt of 4.62%, with a just and reasonable capital structure of 56% common equity and 44% long-term debt;

(10) a just and reasonable return which North Shore should be allowed to earn on its net original cost rate base is 8.50%; this rate of return incorporates a return on common equity of 10.85% and costs of long-term debt of 5.51%, with a just and reasonable capital structure of 56% common equity and 44% long-term debt;

(11) Peoples Gas' rate of return set forth in Finding (9) results in approved base rate net operating income of $119,449,000;

(12) North Shore's rate of return set forth in Finding (10) results in approved base rate net operating income of $16,368,000;

(13) Peoples Gas' rates, which are presently in effect, are insufficient to generate the operating income necessary to permit Peoples Gas the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(14) North Shore's rates, which are presently in effect, are insufficient to generate the operating income necessary to permit North Shore the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(15) the specific rates proposed by Peoples Gas in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; Peoples Gas' proposed rates should be permanently canceled and annulled consistent with the findings herein;

(16) the specific rates proposed by North Shore in its initial filing do not reflect various determinations made in this Order regarding revenue requirement,

cost of service allocations, and rate design; North Shore's proposed rates should be permanently canceled and annulled consistent with the findings herein;

(17) Peoples Gas should be authorized to place into effect tariff sheets designed to produce annual revenues of $619,989,000, including base rate and rider and other revenues other than PGA and coal tar revenues, which represents a gross increase of $112,610,000 (which figures include base rate revenues and a base rate revenue increase of $601,055,000 and $110,928,000, respectively); such revenues will provide Peoples Gas with an opportunity to earn the rate of return set forth in Finding (9) above; based on the record in this proceeding, this return is just and reasonable;

(18) North Shore should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $85,074,000, including base rate and rider and other revenues other than PGA and coal tar revenues, which represent a gross increase of $8,347,000 (which figures include base rate revenues and a base rate revenue increase of $83,384,000 and $8,214,000, respectively); such revenues will provide North Shore with an opportunity to earn the rate of return set forth in Finding (10) above; based on the record in this proceeding, this return is just and reasonable;

(19) the determinations regarding cost of service and rate design contained in the prefatory portion of this Order are reasonable for purposes of this proceeding; the tariffs filed by North Shore and Peoples Gas should incorporate the rates and rate design set forth and referred to herein;

(20) as permitted and required in this Order, North Shore and Peoples Gas shall file Rider VBA with such changes as are approved in this Order as a permanent (non-pilot) rider, and the percentage of fixed costs for purposes of computations under Rider VBA shall be 100% for each of North Shore and Peoples Gas;

(21) as permitted and required in this Order, North Shore and Peoples Gas shall file and implement Riders UEA and UEA-GC as proposed and with the inclusion of the recommended language changes proposed by North Shore and Peoples Gas;

(22) North Shore and Peoples Gas shall evaluate the feasibility of uniform service classification numbering and address this in their next rate cases;

(23) as permitted and required in this Order, North Shore and Peoples Gas shall revise their large volume transportation program tariffs to implement the storage unbundling proposals approved above, including Rider SSC,

and shall implement super pooling under Rider SBS for the monthly storage requirements, twelve months after the date of this Order; and

(24) new tariff sheets authorized to be filed by this order should reflect an effective date consistent with the requirements of Section 9-201(b) as amended.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets presently in effect of The Peoples Gas Light and Coke Company and North Shore Gas Company that are the subject of this proceeding are hereby permanently canceled and annulled, effective at such time as the new tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general rate increase, filed by The Peoples Gas Light and Coke Company and North Shore Gas Company on February 15, 2011, are permanently canceled and annulled.

IT IS FURTHER ORDERED that the $411,643,000 original cost of plant for North Shore at December 31, 2009, and the $2,667,949,000 original cost of plant for Peoples Gas at December 31, 2009, reflected on each Utility's Schedule B-5, Page 1 of 2, are unconditionally approved as the original costs of plant.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company are authorized to file new tariff sheets with supporting workpapers in accordance with Findings 17 and 18 of this Order, applicable to service furnished on and after the effective date of said tariff sheets, which date shall be no later than the earlier of four business days after said sheets are filed or January 16, 2012.

IT IS FURTHER ORDERED that North Shore and Peoples Gas shall adopt and implement Rider VBA as proposed and with the inclusion of the recommended language changes proposed by North Shore and Peoples Gas and with the percentage of fixed costs at 100%.

IT IS FURTHER ORDERED that North Shore and Peoples Gas shall adopt and implement Riders UEA and UEA-GC as proposed and with the inclusion of the recommended language changes proposed by North Shore and Peoples Gas.

IT IS FURTHER ORDERED that North Shore and Peoples Gas shall evaluate the feasibility of uniform service classification numbering and address this in their next rate cases.

IT IS FURTHER ORDERED that North Shore and Peoples Gas shall revise their large volume transportation program tariffs to implement the storage unbundling proposals approved above, including Rider SSC, and shall implement super pooling under Rider SBS, for the monthly storage requirements, twelve months after the date of this Order.

IT IS FURTHER ORDERED that any motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this ____ day of _________, 201_.

(SIGNED) DOUGLAS P. SCOTT