REBUTTAL TESTIMONY

of

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Accounting Department
Financial Analysis Division
Illinois Commerce Commission

Proposed General Increase in Rates for Delivery Service

North Shore Gas Company and The Peoples Gas Light and Coke Company

Docket Nos. 12-0511 and 12-0512
(Consolidated)

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SCHEDULES

Witness Identification

Q. Please state your name and business address.

A. My name is Daniel G. Kahle. My business address is 527 East Capitol Avenue, Springfield, Illinois 62701.

Q. Have you previously filed testimony in this proceeding?

A. Yes, my direct testimony was filed as ICC Staff Ex. 2.0 on November 20, 2012.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to:

1. Respond to the rebuttal testimony of Kyle Hoops, John Hengtgen, James F. Schott and Sharon Moy of North Shore Gas Company ("North Shore") and The Peoples Gas Light and Coke Company ("Peoples Gas") (individually, the "Company" and collectively, the "Companies") regarding my proposed adjustments to rate base, Cash Working Capital ("CWC"), Interest Expense related to Customer Deposits and Interest Expense related to Budget Payment Plan Balances;
2. Respond to certain adjustments to rate base and CWC proposed by Attorney General ("AG") witnesses Michael L. Brosch and David J. Effron and Citizens Utility Board/City of Chicago ("CUB/City") witness Ralph C. Smith;
3. To present schedules reflecting adjustments by Staff witness Brett Seagle to projected utility plant-in-service for the Advanced Metering

Infrastructure Project, Calumet System Upgrade, CNG Fueling Station and Accelerated Main Replacement Program; and

4. To recommend a finding regarding an original cost determination for the Companies.

Schedule Identification

Q. Are you sponsoring any schedules as part of your testimony?

A. Yes. I am sponsoring the following schedules, which show data as of, or for the test year ending, December 31, 2013:

<u>ADJUSTMENT SCHEDULES</u>

Schedules 12.01N and P – Average Rate Base Adjustment
Schedule 12.02N – Gross Utility Plant Additions Adjustments
Schedules 12.03N and P – Cash Working Capital Adjustments
Schedules 12.04N and P – Customer Deposits Interest Adjustment
Schedules 12.05N and P – Budget Payment Plan Balances Interest Adjustment
Schedule 12.06N – Alternate Gross Utility Plant Additions Adjustments
Schedule 12.07P – Adjustments Sponsored by Staff Witness Seagle
Schedule 12.08P – Alternate Adjustments Sponsored by Staff Witness Seagle

For purposes of using the same schedule numbers for adjustments common to North Shore and Peoples Gas, I did not renumber schedules if a preceding direct schedule was not repeated in my rebuttal.

Q. Are you sponsoring any attachments as part of your testimony?

A. No.

Q. Please explain the N and P suffixes that appear with your schedule numbers.

A. These suffixes indicate to which of the Companies a particular schedule applies. The N suffix indentifies a schedule that applies to North Shore, and the P suffix indentifies a schedule that applies to Peoples Gas.

Average Rate Base Adjustments

Q. Please describe Schedules 12.01 N and P; Average Rate Base Adjustments.

A. Similar to Schedules 2.01 N and P, Schedules 12.01 N and P present adjustments necessary to present the rate base as an average balance rather than as a year-end balance as proposed by the Companies. Because the Companies have already calculated their depreciation expense on an average rate base, an adjustment to depreciation expense is not necessary. Therefore, my rebuttal Schedules 12.01 N and P correct my direct Schedules and no longer propose an adjustment to depreciation expense. Also, I have revised the adjustment schedules to reflect the Companies' rebuttal rate base position.

Q. Did you review Mr. Hengtgen's rebuttal testimony regarding your proposed adjustment to use an average rate base?

A. Yes. Mr. Hengtgen did not accept my proposal.[1]

Q. Do you agree with Mr. Hengtgen's rationale for rejecting your proposed adjustments?

A. No. Mr. Hengtgen argues that because Peoples Gas had an infrastructure cost recovery rider ("Rider ICR") in effect when the Companies' 2011 rate cases were

[1] NS-PGL Ex. 27.0, p. 5.

filed that provided timely recovery of the accelerated main replacement program investments, the need for a year-end rate base was not as significant.[2] This rationale does not explain why an average rate base would not provide for adequate recovery of plant investments made throughout a future test year. The Company's argument against an average rate base is that timely recovery would not be obtained for additional significant investments beyond the future test year; however, the Companies can file new rate cases in order to recover the costs of projected investments occurring after the future test year. In fact, the Companies are already required to file biennial rate cases in 2014 and 2016 per Section 9-220(h-1) of the Public Utilities Act ("Act").

Furthermore, Rider ICR applies only to Peoples Gas, and does not help justify an average rate base for North Shore. Indeed, Mr. Hengtgen mentions that Peoples Gas has continued significant investment,[3] but does not apply this argument to North Shore. If continued significant investment did support the use of a year-end rate base, North Shore would not qualify for the use of a year-end rate base.

Q. Does Mr. Hengtgen's discussion on the timing of their rate cases change your position?

A. No. Mr. Hengtgen argues that the Companies' last two rate cases were "very different than this case", because they were filed earlier in the year than the current rate case.[4] This point is irrelevant. Regardless of the time of year that a

[2] *Id.*, p. 6.
[3] *Id.*
[4] *Id.*

rate case is filed, the new rates will go into effect shortly after the Commission enters its Final Order. Moreover, the Companies could have selected a future test year with an ending date as far out as July 31, 2014. Instead the Companies chose a future test year ending December 31, 2013. Any perceived disadvantage from this choice that they alone made should not now be cause for the Commission to adopt an improperly measured rate base that is inconsistent with Commission practice.

Q. Do you have any reply to Mr. Hengtgen's testimony regarding the applicability of the formula rate process (NS-PGL Ex. 27.0, p. 6)?

A. No. I did not refer to the formula rate process as support for my position[5]. The formula rate process is governed by Article XVI of the Act, whereas this case is governed by Article IX of the Act. Article XVI cases are subject to protocols that do not impact Article IX cases. Thus, the current rate cases are not subject to the formula rate process.

Q. Do you have any reply to Mr. Hengtgen's response regarding the other rate cases you referenced in your direct testimony supporting the use of an average rate base when a future test year is selected by the utility?

A. Yes. Mr. Hengtgen states that "… they have not shown the facts to be similar and differences in facts, possibly significant, may exist, such as flat rates of plant

[5] Staff Ex. 2.0, pp. 3-11.

investment."[6] Contrary to this unsupported assertion, the rate cases that I referenced in my direct testimony do have similar facts to this case.

Two of the rate cases to which I refer are the Companies' prior rate cases: Docket Nos. 11-0280/0281 (filed February 15, 2011) and 09-0166/0167 (filed February 25, 2009). Both rate cases were filed with a future test year using an average rate base.[7] Both rate cases also had an increasing rate base as demonstrated by PGL Ex. 7.2 and NS Ex. 7.2 showing increasing gross and net plant from 2006 through 2011 for both Peoples Gas and North Shore.

A third rate case referenced in my direct testimony is Docket No. 04-0779, a general rate case for Northern Illinois Gas Company ("Nicor").[8] Nicor also had increasing levels of investment in the test year,[9] and chose a future test year. Nicor's test year ended December 31, 2005 which was approximately 13 months after tariffs were filed on November 4, 2004.[10] Like the Companies, Nicor proposed a year-end rate base contending it a necessity in order to fully recover its investments.[11] The Commission found that utilities have sufficient flexibility in making their rate cases forward-looking and that the Company had not supported the use of a year-end rate base:

> The Company selected a forecasted, future test year that already reflects the Company's increasing investment on a forward-looking basis relative to when the Company filed its case. As Staff noted,

[6] *Id*., p. 7.
[7] Staff Ex. 2.0, p. 9.
[8] *Id*., pp. 7-8.
[9] Docket No. 04-0779, Order, September 20, 2005, p. 8.
[10] *Id*., pp. 1, 3.
[11] *Id*., p. 5.

> the Commission gives utilities sufficient flexibility to make their rate cases forward looking. In light of the forward looking test year selected by the Company, the facts in this case do not support using a year-end rate base with a future test year. The average rate base proposed by Staff more accurately reflects the cost of service for the test year because it better matches the level of rate base during the test year with the revenues and expenses during the test year. The Commission finds that the average rate base proposed by Staff is more appropriate than the year-end rate base proposed by the Company, given the future test year selected by the Company.[12]

A fourth rate case referenced in my direct testimony is Docket No. 90-0072, a rate proceeding for Central Illinois Public Service Co ("CIPS"). This case was also a future test year with a requested year-end rate base. The Commission also ruled that an average rate base should be used because an average rate base generally provides a better matching of test year rate base with operating revenues and expenses. The Commission further concluded that if utilities wanted more "forward looking" rate bases, the utilities have the option of making the rate case filing based on more "forward looking" test years.[13]

Q. Even if the Company's year-end rate base were more forward looking than the average rate base, how should the Commission weigh that against the benefit of matching the rate base to the operating revenues and expenses for the test year?

A. When deciding whether to use an average rate base or a year-end rate base with a particular test year, two important but sometimes competing concerns should be considered. On the one hand, when using a historical test year, a year-end

[12] Order, Docket No. 04-0779, September 20, 2005, p. 8.
[13] Order, Docket No. 90-0072, November 28, 1990, p. 4.

rate base can be more forward looking. On the other hand, an average rate base more accurately reflects the cost of providing service for the test year because it better matches the cost of capital for the rate base during the test year with the other costs incurred during the test year. A future test year is based on financial projections and therefore is already forward looking. Therefore, it is appropriate to give more weight to the matching concern than to the forward looking concern in the case of a future test year.

Q. Would using a year-end rate base be more representative of the rate base that will exist when the proposed rates will be in effect than would an average rate base?

A. No. That position fails to take into account that a future test year is based on financial projections, and therefore, is already forward looking. During a time of increasing investment, a year-end rate base can be more representative of the rate base that will exist when the proposed rates will be in effect than would an average rate base if the test year ends before rates become effective. Because of this, the Commission typically permits the use of a year-end rate base with an historical test year, which is based on historical financial information. However, in this case, the Companies have proposed a future test year in which the test year ends five months after rates from this proceeding will go into effect.

Mr. Hengtgen is correct that the Commission has previously approved year-end rate bases for historical test years. For a historical test year, however, since the test year-end is in the past, new rates would go into effect after the rate base has been put into service. Utilities may add pro forma adjustments that will occur within 12 months of the filing of tariffs. Given the approximately 11-month rate case review process; however, new rates would likely go into effect after pro forma adjustments have been put into service. In this proceeding, rates would become effective around July 1, 2013. Applying Mr. Hengtgen's discussion of when rates go into effect after a historical test-year[14] to this proceeding, the Commission could only consider rate base that has been put into service prior to new rates going into effect. In other words, for the test year, the Commission could only consider an average rate base which represents a level of investment made through mid-test year rather than a year-end rate base which represents a level of investment made through the test year-end.

Q. Do you have any reply to Mr. Hengtgen's argument that there was no indication of which other rate cases proposed an end of year rate base method?

A. Yes. Mr. Hengtgen stated that "…they do not indicate in which of the cases an end of year rate base method was proposed.[15] In my direct testimony, I noted that a year-end rate base had been proposed in two prior rate cases: Docket No. 90-0072, CIPS and Docket No. 04-0779, Nicor. Both rate cases proposed a year-end rate base with a future test year. Both proposals were rejected by the Commission.[16]

[14] NS-PGL Ex. 27.0, p. 8.
[15] *Id.*, p. 7.
[16] Staff Ex. 2.0, pp. 6-8.

Q. Mr. Hengtgen discusses matching in relation to the Companies' proposal to use a year-end rate base. Did his arguments change your position that an average rate base better matches the level of rate base investment with the revenues and expenses for a future test year than does a year-end rate base?

A. No. Mr. Hengtgen tries to first make a point by discussing the use of a year-end rate base with a historical test year.[17] Since the current proceeding is a future test year, this discussion is irrelevant.

Mr. Hengtgen also attempts to dismiss concerns about the mismatch between a year-end rate base and operating expenses by discussing depreciation expense.[18] Mr. Hengtgen overlooks, however, that net operating income is a function of rate base because net operating income is rate base multiplied by the overall rate of return. Uncollectible expenses and State and Federal income taxes are then affected by the level of net operating income. Therefore, Mr. Hengtgen's dismissal of concerns of mismatching rate base and operating expenses is incomplete and incorrect.

Mr. Hengtgen also does not discuss the mismatch of revenues. The Companies' proposed year-end rate base would result in revenues that represent a level of investment for the test year that would not exist until the last day of the test year. An average rate base would result in revenues for the test year that represent a level of investment made throughout the test year.

[17] NS-PGL Ex. 27.0, p. 8.
[18] *Id*., pp. 8-9.

Q. In his rebuttal testimony, Mr. Hengtgen appears to take issue with your testimony stating that year-end rate base is not mentioned in the referenced Commission rules.[19] Do you have a response to his argument?

A. Yes. Mr. Hengtgen included a quote from the Final Order in Docket No. 02-0509 discussing the language of the Commission's rule in 83 Ill. Adm. Code 285.2005(e). Mr. Hengtgen did not, however, rebut my statement that year-end rate base is not mentioned in the referenced Commission rules.

Q. In his rebuttal testimony, Mr. Schott discusses the timing of the Companies' filing and their test year choice. Do you have response to his comments?

A. Mr. Schott discusses the requirement that the Companies file a rate case on or before August 1, 2012 and their choice of a calendar year test year. Mr. Schott also discusses difficulties in choosing a test year other than year-end.[20] While the required filing date speaks for itself, and I cannot comment on the Companies' difficulties in choosing a test year other than year-end, I do note that the Companies could have chosen a test year that ended 24 months after the date the Companies filed the new tariffs. At least one Illinois utility, Illinois American Water Company ("IAWC"), has recently filed rate cases with a test year ending on a date other than the end of its fiscal year. IAWC has a fiscal year ending December 31. IAWC's three most recent rate cases were filed with a future test year ending June 30, 2009 (Docket No. 07-0507); December 31, 2010 (Docket No. 09-0319); and September 30, 2013 (Docket No. 11-0767).

[19] *Id.*, p. 9.
[20] NS-PGL Ex. 22.0, pp. 8-9.

Q. Mr. Schott refers to Staff proposing to remove investments from rate base.[21] Does your proposed average rate base adjustment remove investments from rate base?

A. No. My proposed adjustment to present rate base as an average balance does not remove any investments from rate base. My proposed adjustment causes rate base to appropriately reflect the level of investments made throughout the test year.

Q. Did any other parties propose average rate base adjustments?

A. Yes. Mr. Brosch,[22] Mr. Effron[23] and Mr. Smith[24] all propose that the Companies' use an average rate base in this proceeding. My adjustments proposed in ICC Staff Schedules 12.01 N and P are necessary to present the Companies' rate base as an average balance rather than as a year-end balance and should be adopted by the Commission.

Gross Utility Plant Additions Adjustments

Q. Please describe Schedule 12.02N; Gross Utility Plant Additions Adjustments.

A. These adjustments use the same methodology as my Schedule 2.02N. I withdraw my adjustment to gross utility plant additions for Peoples Gas. Also, I have revised the adjustment schedules to reflect North Shores' rebuttal rate base position and corrected some calculation errors.

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[21] *Id.*, p. 2.
[22] AG Ex. 1.0, pp. 10-13.
[23] AG Ex. 2.0, pp. 4-8.
[24] CUB-City Ex. 1.0, pp. 13-17.

Q. Why did you drop the proposed adjustment for Peoples Gas?

A. The additions that Mr. Seagle reviewed in order to make his recommendations comprise over 96% of Peoples Gas' proposed 2013 additions. An adjustment based on a budget-to-actual analysis for 2013 plant additions would have been almost completely duplicative of Mr. Seagle's adjustments.

Q. Do you continue to propose an adjustment for North Shore?

A. Yes. The adjustment to North Shore is necessary to reflect the Company's inability to forecast for unforeseen changes. Most of Peoples Gas' proposed 2013 additions have been analyzed by Mr. Seagle, and Mr. Seagle has proposed adjustments to reflect the likely level of expenditure. My adjustment to North Shore's proposed 2013 additions is necessary to reflect the proposed additions based on the Company's historical spending pattern.

Q. Did you review Mr. Hoops' rebuttal testimony regarding your proposed adjustments to gross utility plant?

A. Yes. Mr. Hoops did not accept my proposal.

Q. Did you agree with Mr. Hoops' rationale for rejecting your proposed adjustments?

A. No. Mr. Hoops argued that using averages over different periods would produce different results.[25] While that is true, it is not a convincing argument that a three-year period is not appropriate.

[25] NS-PGL Ex. 28.0, p. 3.

While Mr. Hoops primarily discusses Peoples Gas, he applies his conclusions to North Shore as well.

Mr. Hoops also relates that Peoples Gas had budget variances during the same three-year period for the accelerated main replacement program ("AMRP") for various reasons and cushion gas due to difficulties in forecasting gas prices. Mr. Hoops suggests that, since he considers the AMRP variances in 2011 to be an anomaly, 2011 should not be included in the analysis.[26]

Mr. Hoops further notes that North Shore's variance is primarily due to public improvement projects being rescheduled or delayed, which is outside of North Shore's control.[27] In any time period, rescheduled public improvement projects may be outside of North Shore's control, thus public improvement projects should be included in the calculation of the average. Mr. Hoops' testimony merely demonstrates the uncertainty of budgeting capital expenditures as circumstances beyond the control of the Companies can prevent their actual capital expenditures from matching budgeted amounts.

Mr. Hoops notes that if a low year of expenditures like 2011 is "factored out", the results would be positive.[28] Selectively ignoring years with undesired results produces an upwardly biased result that is not reflective of the Company's historical average of expenditures. Years like 2011 exemplify the need for this

[26] *Id*., pp. 3-4.
[27] *Id*., pp. 4-5.
[28] *Id*., p. 3.

adjustment: the Companies cannot control events unknown during their planning process.

Mr. Hoops states that the Companies' historical-based forecasting is accurate allowing for unforeseen external changes.[29] Mr. Hoops refers to non-budgeted and unforeseen increases in costs for AMRP in 2012,[30] but does not suggest that unforeseen events will not occur in the test year. Mr. Hoops states that the price of natural gas is outside of Peoples Gas' control[31], but does not suggest that the price is now within their control. It is this very fact that calls for my adjustment: that the Companies cannot forecast for unforeseen changes. My three-year average of the Companies' spending pattern provides a historical basis on which to adjust planned capital expenditures for changes of plans and/or circumstances beyond the control of the Companies.

Q. Why do you think a three-year period is better than the analyses discussed by Mr. Hoops?

A. The more recent three-year period better represents the Companies' current operations and would provide a more suitable basis on which to predict the Companies' future capital spending.

Q. Have you previously used a three-year period for this type of analysis?

A. Yes. In two recent rate cases, Docket No. 09-0319 - IAWC and 11-0280/0281 – the Companies last rate proceeding, I proposed adjustments to plant-in-service

[29] *Id*., p. 1.
[30] *Id*., p. 3.
[31] *Id*.

based on a three-year history of actual capital spending compared to planned spending. Both IAWC and the Companies accepted my proposed adjustments. IAWC accepted my adjustments for the purpose of that rate case.[32] The Companies accepted my adjustments in order to narrow the number of contested issues.[33]

Q. Why isn't data from 2012 part of your plant analysis?

A. Plant investment data from 2012 was not available for consideration in my direct testimony. Company responses to Staff Data Requests DGK-4.03, 4.04 and 4.05, which request 2012 data when it becomes available, are still outstanding at this time. The Companies have indicated that they will provide this data when it is available. If that information is made available to me, in a timely manner, I intend to revise Schedule 12.02N, page 4 from my rebuttal testimony to include the historical spending pattern for budgeted capital expenditures for 2010, 2011 and 2012 and offer it as part of supplemental rebuttal testimony.

Cash Working Capital Adjustments

Q. Did you review Mr. Hengtgen's rebuttal testimony regarding your proposed adjustments to CWC?

A. Yes. Mr. Hengtgen did not accept my proposal to use zero lag days for pass-through taxes.

[32] Docket No. 09-0319, IAWC Ex. 6.00R1, p. 4.
[33] Docket Nos. 11-0280/0281 (cons.), NS-PGL Ex. 40.0 CORR, pp. 3-4.

Q. Did you agree with Mr. Hengtgen's rationale for rejecting your proposed adjustments to CWC?

A. No.

Pass-Through Taxes Revenue Lag

Q. What were Mr. Hengtgen's rebuttal arguments against using zero lag days for pass-through taxes?

A. Mr. Hengtgen attempted to redefine the nature of pass-through taxes. Mr. Hengtgen attempts to mask the nature of pass-through taxes by explaining how the Companies collect the taxes.[34] Despite Mr. Hengtgen's attempt, the form of the transaction does not change its substance. These taxes are described as "pass-through" because that is what they are. Utilities collect the taxes from ratepayers and pass them through to the taxing authority. Pass-through taxes are not included in utilities' revenue requirements because pass-through taxes are not a part of utility service. Since pass-through taxes are not a payment for utility services, they are not revenue and cannot have a revenue lag. CWC is the amount of funds required from investors to finance a utility's day-to-day operations. Pass-through taxes are not part of utility operations and are provided by ratepayers.

Q. What were Mr. Hengtgen's rebuttal arguments for lead days for pass-through taxes?

[34] NS-PGL Ex. 27.0, p. 16.

A. Mr. Hengtgen discusses the various pass-through tax lead times and is not responsive to the proposal to use zero lag days for pass-through taxes.[35] While Mr. Hengtgen spends considerable time discussing lead times and the number of days the Companies hold pass-through taxes, it does not appear that he is making a proposal to modify pass-through tax lead times. The pass-through tax lead times proposed by Mr. Hengtgen are not contested.

Mr. Hengtgen's rebuttal testimony confirms that, except for the ICC Gas Revenue tax, the Companies collect pass-through taxes, hold them and later remit them.[36]

Mr. Hengtgen also makes a flawed Net Lag Approach analysis of pass-through tax.[37] Mr. Hengtgen arrives at a net lag for each pass-through tax by netting revenue lag days and pass-through tax lead days. Mr. Hengtgen's analysis is flawed since the non-revenue pass-through taxes do not have a revenue lag; it makes no sense to net a revenue lag against the lead days proposed by the Companies.

Q. Did any other parties propose adjustments to pass-through tax lag?

A. Yes. Mr. Brosch proposes a similar adjustment to set lag for pass-through taxes to zero.[38]

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[35] *Id*., pp. 17-24.
[36] *Id*., pp. 19-20.
[37] *Id*., pp. 20-21.
[38] AG Ex. 1.0, pp. 52-54.

Pension and OPEB Expense Lead

Q. Did you review Mr. Hengtgen's rebuttal testimony regarding your proposed lead days for pension and OPEB expense?

A. Yes. Mr. Hengtgen did not accept my proposal to use the expense leads for inter-company billings for pension and OPEB expense.

Q. Did any of Mr. Hengtgen's arguments cause you to change your position regarding your proposed lead days for pension and OPEB expense?

A. No. I still propose using the expense leads for inter-company billings for pension and OPEB expense in the CWC calculation. I reject the Companies' proposal for the same reasons stated in my direct testimony.[39] Amounts included in rate base are items funded by investors on which the investors earn a return, while amounts included in CWC are expenses from the operating statement. Regardless of whether or not an amount for pensions or OPEB is included in rate base, both items also have an operating expense component in the revenue requirement. It is the operating expense component that generates the CWC lead that I propose. I further note that my methodology is consistent with the way the Companies presented CWC with respect to pensions and OPEBs in past rate case proceedings. It is illogical to say that an expense from the operating statement is should be in rate base.

Q. How should operating income or expense component affect the CWC requirement?

[39] Staff Ex. 2.0, pp. 21-22.

A. The CWC requirement should be the amount of funds required from investors to finance the day-to-day operations of the Companies. Generally, a CWC requirement is created by revenue lag and minimized by operating expenses. The CWC requirement may be positive or negative, depending on whether revenues are received, on average, slower or faster than expenses are paid.

The recovery of pension expense, as reflected in the revenue requirement, is an expense of providing utility service. The Company proposes to include the revenue lag associated with pension and OPEB, which increases the CWC requirement, while improperly ignoring the associated pension and OPEB expense that would reduce the CWC requirement. The Commission's practice is to use the operating statement to represent the funds required from investors to finance operations. To make that representation, the operating statement is adjusted to eliminate items not financed by investors such as depreciation and amortization. The Commission has not allowed utilities to pick and choose items from the revenue requirement to include in the CWC calculation. Pension and OPEB expense have an expense lead as evidenced in the Companies' prior rate cases.[40] Including them in the CWC calculation with a zero expense lead has the same affect as excluding them altogether.

Q. How does including an asset or liability in rate base affect the CWC calculation?

A. It does not. The CWC calculation is based on the operating statement component of the revenue requirement. Rate base components like an asset or

[40] *Id*.

liability are typically categorized as balance sheet items. An asset or liability does not equate to operating income or expense. The recovery of pension expense, as reflected in the revenue requirement, is an expense of providing utility service. The CWC calculation should measure the impact the pension expense and OPEB operation expense have on the Companies' CWC requirement for operations.

Q. Did any other parties propose a similar adjustment to pension and OPEB lead days?

A. Yes. Mr. Brosch proposes a similar adjustment but uses the lead days for Other Operations and Maintenance as the lead days for pension and OPEB expense.[41] While I would accept Mr. Brosch's proposal, I believe that the expense lead days for inter-company billings is a better choice because this is the type of lead days the Companies used in their previous rate cases 11-0280/0281.[42]

Q. Did Mr. Brosch make any other proposals regarding pension and OPEB expense in the CWC calculation?

A. Yes. Mr. Brosch offered an alternative proposal for pension and OPEB expense in the CWC calculation. Mr. Brosch proposed to remove an amount equal to the pension and OPEB expense from revenue or assign pension and OPEB expense lead days equal to the revenue lag.[43] While I believe that including all operating items from the revenue requirement with the appropriate lag or lead is the best

[41] AG Ex. 1.0, p. 55.
[42] Staff Ex. 2.0, p. 20.
[43] AG Ex. 1.0, p. 55.

method for calculating the CWC requirement, Mr. Brosch's alternative proposal would provide an acceptable adjustment of the Companies' proposed CWC requirement if the Commission did not adopt either of our proposals to provide for leads days for pension and OPEB expense.

Q. Mr. Hengtgen made reference to your position on a similar issue in a recent ComEd formula rate case, Docket No. 11-0721.[44] Is his point valid?

A. No. In the ComEd proceeding, I prepared a CWC calculation with zero lead days for pension and OPEB expenses (Employee Benefits). In that docket, the Company's initial proposal was to use zero lead days for pension and OPEB expenses. I did not oppose their proposal. Since that case, however, I've had the opportunity to further consider this issue and have set forth my rationale as to why the approach and corresponding adjustments I now make are reasonable. Mr. Hengtgen has not offered any valid argument as to why the rationale I have set forth in this proceeding is untenable.

Other Issues

Q. Mr. Hengtgen points to an omission in a reference you made to Commonwealth Edison Company ("ComEd"). Is he correct?

A. Yes. Mr. Hengtgen refers to my statement that the lag for pass-through taxes had been set to zero for ComEd in the Final Commission Orders entered in Docket Nos. 10-0467 and 11-0721.[45] I made a reference to these ComEd Orders in support of using similar treatment of the lag for similar pass-through

[44] NS-PGL Ex. 27.0, p. 31.
[45] *Id.*, p. 28.

taxes. I failed to note, however, that for two pass-through taxes that ComEd collects but the Companies do not collect, i.e., the Illinois Excise Tax and City of Chicago Infrastructure Maintenance Fee, the lag was not set to zero. The Commission's acceptance of a lag for these two pass-through taxes is relevant to ComEd's electric utility, but not to the Companies who do not collect these two pass-through taxes.

I note that subsequent to the filing of my direct testimony, the Commission has issued Final Orders for a more recent rate case for ComEd[46] and Ameren[47] Illinois Company ("AIC"). Both of these Orders set the lag to zero for the pass-through taxes that the Companies also collect, i.e., the Energy Assistance Charges ("EAS") and Gross Receipts/Municipal Utility Tax ("GR/MUT").

Q. Mr. Hengtgen makes an issue of "investor financing" that you discussed in your testimony and in your response to NS-PGL Data Request 7.02(c). Is this a valid issue?

A. No. The data request asked if the Companies have asked for investor related financing for pass-through taxes.[48] Rather than ask for investor related financing, both Companies' include a revenue lag for pass-through taxes which increases CWC which increases rate base. Increasing rate base means that the Companies are asking for ratepayer supplied funding for the pass-through taxes collected from ratepayers. Likewise, in my direct testimony I note that there is

[46] Order, Docket No. 12-0321, December 19, 2012, Appendix B, lines 2-3.
[47] Order, Docket No. 11-0721, December 5, 2012, p. 39.
[48] NS-PGL Ex. 27.0, p. 29.

nothing for investors to finance because pass-through taxes are collected from ratepayers.[49] Since there is nothing for investors to finance, there is no reason to add a lag to CWC and thereby to rate base and provide a return to investors.

Customer Deposits Interest Adjustments

Q. Please describe Schedules 12.04 N and P, Customer Deposits Interest Adjustments.

A. Schedules 12.04 N and P are the same as Schedules 2.04 N and P.

Q. Did you review Ms. Moy's rebuttal testimony regarding your proposed adjustments to Customer Deposits Interest?

A. Yes. Ms. Moy accepted using the interest rate set by the Commission on customer deposits.[50] The Commission set this rate at 0% after the Companies filed rebuttal testimony. Since the Companies' rebuttal position does not reflect the 0% interest rate, I still propose the adjustment.

Budget Payment Plan Balances Interest Adjustments

Q. Please describe Schedules 12.05 N and P, Budget Payment Plan Balances Interest Adjustments.

A. Schedules 12.05 N and P are the same as Schedules 2.05 N and P.

Q. Did you review Ms. Moy's rebuttal testimony regarding your proposed adjustments to Budget Payment Plan Balances Interest?

[49] Staff Ex. 2.0, p. 16.
[50] NS-PGL Ex. 26.0, p. 5, footnote 2.

A. Yes. Ms. Moy accepted using the interest rate set by the Commission on Budget Payment Plan Balances.[51] The Commission set this rate at 0% after the Companies filed rebuttal testimony. Since the Companies' rebuttal position does not reflect the 0% interest rate, I still propose the adjustment.

Alternate Gross Utility Plant Additions Adjustments

Q. Please describe Schedules 12.06 N and P, Alternate Gross Utility Plant Additions Adjustments.

A. Schedules 12.06 N and P are the same as Schedules 12.02 N and P except that Schedules 12.06 N and P present adjustments assuming that the Commission adopts the Companies' year-end rate base proposal rather than the average rate base I propose. The differences are: 1) Staff adjustments are not divided by two in Schedule 12.06 as they are in Schedule 12.02 that reflects use of an average rate base; and 2) page 4 of Schedule 12.02 is not repeated in Schedule 12.06.

Adjustments Sponsored by Staff Witness Seagle

Q. Please describe Schedule 12.07P, Adjustments Sponsored by Staff Witness Seagle.

A. Schedule 12.07P, presents adjustments as proposed in the direct testimony of Staff witness Brett Seagle, Staff Ex. 16.0. In Schedule 12.07P, I provide the calculations for adjustments to depreciation expense, accumulated depreciation and accumulated deferred income taxes ("ADIT") derived from Mr. Seagle's proposed adjustments.

[51] *Id*., footnote 3.

Alternate Adjustments Sponsored by Staff Witness Seagle

Q. Please describe Schedule 12.08P, Alternate Adjustments Sponsored by Staff Witness Seagle.

A. Schedule 12.08P is the same as Schedule 12.07P except that Schedule 12.08P presents adjustments assuming that the Commission adopts the Companies' year-end rate base proposal rather than the average rate base I propose. The difference is that Staff adjustments are not divided by two in Schedule 12.08P as they are in Schedule 12.07P that reflects use of an average rate base.

Budget Plan Balances

Q. Did you review Mr. Effron's proposal to adjust budget plan balances?

A. Yes. After reviewing Mr. Effron's direct testimony and Mr. Hengtgen's rebuttal testimony, it appears that Mr. Hengtgen has reduced budget plan balances to a reasonable level using averages from 2011 and 2012.

Original Cost Determination

Q. Did you review Mr. Hengtgen's rebuttal testimony regarding your proposed Original Cost Determination?

A. Yes. Mr. Hengtgen did not accept my proposal since my proposal deducted previous Commission disallowances for calendar year 2012, but the original cost determination is as of December 31, 2011.[52]

Q. Did you agree with Mr. Hengtgen's rationale for rejecting your proposal?

[52] NS-PGL Ex. 27.0, p. 36.

A. Yes. Therefore, I agree with Mr. Hengtgen's original cost Proposal that the Commission's Order should state:

> It is further ordered that the $3,016,429,000 original cost of plant for Peoples Gas at December 31, 2011, reflected on Peoples Gas' NS-PGL Ex. 27.14P, Line 19, Column B, is unconditionally approved as the original cost of plant. It is also ordered that the $424,299,000 original cost of plant for North Shore at December 31, 2011, reflected on North Shore's NS-PGL Ex. 27.14N, Line 17, Column B, is unconditionally approved as the original cost of plant.[53]

Uncollectible Accounts Expense for Rider UEA

Q. Did you review Ms. Moy's rebuttal testimony regarding your proposal to use the uncollectible accounts expense determined by the Commission in this proceeding to determine incremental uncollectible adjustments in Rider UEA?

A. Yes. Ms. Moy accepted my proposal[54] for my recommended language for the Order.[55]

Conclusion

Q. Does this conclude your prepared rebuttal testimony?

A. Yes.

---

[53] *Id*., lines 789-796.
[54] NS-PGL Ex. 26.0, p. 6.
[55] Staff Ex. 2.0, p. 27.

North Shore Gas Company
Average Rate Base Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description	Gross Utility Plant	Accumulated Depreciation	ADIT	Net Retirement Benefits	(not used)	Total Rate Base Adjustments	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) Sum C thru G	(I)
1	2013 Beginning Gross Plant	$ 444,121	$ (181,068)	$ (68,375)	$ (638)	$ -	$ 194,040	NS Ex. 19.1
2	2013 Average Gross Plant	455,252	(185,339)	(68,384)	(2,198)	-	199,332	(Line 1 + Line 3) / 2
3	2013 Year-End Gross Plant	466,382	(189,609)	(68,392)	(3,758)	-	204,623	NS-PGL 27.1N
4	Staff Adjustments	$ (11,131)	$ 4,271	$ 9	$ 1,560	$ -	$ (5,292)	Line 2 - Line 3

North Shore Gas Company
Gross Utility Plant Additions Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description		Amount	Source
(A)	(B)		(C)	(D)
1	Staff Adjustment to Utility Plant-in-Service	$	(1,201)	ICC Staff Ex. 12.0, Sch. 12.02N, p. 2, Colm. F, Line 15
2	Staff Adjustment to Depreciation Expense	$	(33)	ICC Staff Ex. 12.0, Sch. 12.02N, p. 2, Colm. K, Line 15
3	Staff Adjustment to Accumulated Depreciation	$	33	- ICC Staff Ex. 12.0, Sch. 12.02N, p. 2, Colm. K, Line 15
4	Staff Adjustment to Accumulated Deferred Taxes	$	9	= - ICC Staff Ex. 12.0, Sch. 12.02N, p. 2, Colm. N, Line 15 - ICC Staff Ex. 12.0, Sch. 12.02N, p. 2, Colm. O, Line 15 - ICC Staff Ex. 12.0, Sch. 12.02N, p. 3, Colm. F, Line 15

North Shore Gas Company
Gross Utility Plant Additions Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Item	Depr Method	2013 Gross Additions less Retirements	Projected Additions per Staff	Staff Adjustment	Book Depr %
(A)	(B)	(C)	(D)	(E)	(F)	(G)
			NS-PGL Ex. 19.2 N REV *	89.21 % (D* 89.21%)	12.02N p. 4 (E - D) / 2 *	Co. Sch C-12, p. 4
1	Distribution	Macrs 20	18,867	16,831	(1,018)	2.4500%
2	Underground Storage	Macrs 15	0	0	0	1.1500%
3	Liquefied Natural Gas	Macrs 15	0	0	0	0.0000%
4	Transmission - Not Leased	Macrs 15	3,000	2,676	(162)	1.8300%
5	General	Macrs 5	1,319	1,177	(71)	7.1300%
6	Intangible	SL 3	0	0	0	0.0000%
7	Production	Macrs 7	75	67	(4)	1.1200%
8	ARO Obligation	None	0	0	0	0.0000%
9	Total Account 101		23,261	20,751	(1,255)	
10						
11	Recoverable Natural Gas (Account 117)	None	0	0	0	0.0000%
12	Total Plant in Service		23,261	20,751	(1,255)	
13	Construction Work in Progress (Account 107)	None	(1,000)	(892)	54	0.0000%
14						
15	Total Utility Plant		22,261	19,858	(1,201)	

North Shore Gas Company
Gross Utility Plant Additions Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Tax Depr %	Federal Tax Depr	State Tax Depr	Book Depreciation	Federal M1	State M1	2013 Federal Def Tax	2013 State Def Tax	Line
(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
Staff DR DGK-11.02	(F * H)	(F * H)	(F * G)	(I - K)	(J - K)	(L * 35%)	(M * 9.5%)	
3.7500%	(38)	(38)	(25)	(13)	(13)	(5)	(1)	1
5.0000%	0	0	0	0	0	0	0	2
0.0000%	0	0	0	0	0	0	0	3
5.0000%	(8)	(8)	(3)	(5)	(5)	(2)	0	4
20.0000%	(14)	(14)	(5)	(9)	(9)	(3)	(1)	5
0.0000%	0	0	0	0	0	0	0	6
3.7500%	0	0	0	0	0	0	0	7
0.0000%	0	0	0	0	0	0	0	8
	(60)	(60)	(33)	(27)	(27)	(10)	(2)	9
								10
0.0000%	0	0	0	0	0	0	0	11
	(60)	(60)	(33)	(27)	(27)	(10)	(2)	12
0.0000%	0	0	0	0	0	0	0	13
								14
	(60)	(60)	(33)	(27)	(27)	(10)	(2)	15

North Shore Gas Company
Gross Utility Plant Additions Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description	Days(1)	Ratio	Liberalized Depreciation Statutory Rate Per Staff	Liberalized Depreciation Statutory Rate Prorated	Source
[A]	[B]	[C]	[D]	[E]	[F]	(G)
1	2013 Additions Adjustment - Federal Deferred Tax			$ (10)		ICC Staff Ex. 12.0, Sch. 12.02N, p. 2, Colm. N, Line 15
			(C/D 16)		(D * E)	
2	January		100.0%	(1)	(1)	
3	February		100.0%	(1)	(1)	
4	March		100.0%	(1)	(1)	
5	April		100.0%	(1)	(1)	
6	May		100.0%	0	0	
7	June		100.0%	(1)	(1)	
8	July	154	83.2%	(1)	(1)	
9	August	123	66.5%	(1)	(1)	
10	September	93	50.3%	0	0	
11	October	62	33.5%	(1)	0	
12	November	32	17.3%	(1)	0	
13	December	1	0.5%	(1)	0	
14	Total 12/31/2013			$ (10)	$ (7)	
15	Impact of Proration				$ 3	
16	Notes: (1)Total days in period:		185			

Assumes rates become effective July 1, 2013.

North Shore Gas Company
Gross Utility Plant Additions Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description	Actual Capital Expenditures (1)	Planned Capital Expenditures (1)	Source
(A)	(B)	(C)	(D)	(E)
1	Total Company			
2	2009	$ 14,490	$ 9,627	Co. Sch. G-8
3	2010	10,259	19,019	Co. Sch. G-8
4	2011	12,438	13,040	Co. Sch. G-8
5		-	-	
6	3-Year Totals	$ 37,187	$ 41,686	
7	Average Planned Capital Expenditures Expended		89.21%	Col. (C), line 5 / Col. (D), line 5

North Shore Gas Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No. (A)	Item (B)	Amount (C)	Lag (Lead) (D)	CWC Factor (D) / 365 (E) (D/365)	CWC Requirement (C) x (E) (F)	Column (C) Source (G)
1	Revenues	$ 171,354	40.50	0.11096	$ 19,013	ICC Staff Ex. 12.0, Sch. 12.03N, p. 2, Line 7
2	Pass Through Taxes	15,849	0.00	0.00000	-	Sum of lines 21 - 24 below
3	Total	$ 187,203			$ 19,013	Line 1 + Line 2
4	Payroll and Withholdings	$ 9,012	(14.04)	(0.03847)	(347)	ICC Staff Ex. 12.0, Sch. 12.03N, p. 3, Line 3
5	Incentive Pay	170	(250.50)	(0.68630)	(117)	NS-PGL Ex. 27.10N, p. 1, Line 5
6	Inter Company Billings	30,239	(33.91)	(0.09290)	(2,809)	NS-PGL Ex. 27.10N, p. 1, Line 6
7	Natural Gas	109,510	(40.39)	(0.11066)	(12,118)	NS-PGL Ex. 27.10N, p. 1, Line 7
8	Pension and OPEB	4,720	(33.91)	(0.09290)	(439)	NS-PGL Ex. 27.10N, p. 1, Line 8
9	Other Benefits	1,968	(41.46)	(0.11359)	(224)	NS-PGL Ex. 27.10N, p. 1, Line 9
10	Other Operations and Maintenance	2,335	(44.28)	(0.12132)	(283)	ICC Staff Ex. 12.0, Sch. 12.03N, p. 2, Line 21
11	Federal Insurance Contributions (FICA)	595	(16.13)	(0.04419)	(26)	ICC Staff Ex. 12.0, Sch. 12.03N, p. 3, Line 9
12	Federal Unemployment Tax	4	(60.88)	(0.16679)	(1)	NS-PGL Ex. 27.10N, p. 1, Line 13
13	State Unemployment Tax	13	(72.11)	(0.19756)	(3)	NS-PGL Ex. 27.10N, p. 1, Line 14
14	Property/Real Estate Taxes	260	(378.73)	(1.03762)	(270)	NS-PGL Ex. 27.10N, p. 1, Line 15
15	Invested Capital Tax	1,405	(30.14)	(0.08258)	(116)	ICC Staff Ex. 12.0, Sch. 12.03N, p. 3, Line 6
16	Corporation Franchise Tax	25	(179.73)	(0.49241)	(12)	NS-PGL Ex. 27.10N, p. 1, Line 17
17	Sales, Use and Accelerated Tax	6	(42.88)	(0.11748)	(1)	NS-PGL Ex. 27.10N, p. 1, Line 18
18	Federal Excise Tax	1	(75.75)	(0.20753)	-	NS-PGL Ex. 27.10N, p. 1, Line 19
19	-	-	-	-	-	
20	Unauthorized Insurance Tax	15	155.39	0.42573	6	NS-PGL Ex. 27.10N, p. 1, Line 20
21	ICC Gas Revenue Tax	198	35.74	0.09792	19	NS-PGL Ex. 27.10N, p. 1, Line 21
22	Gross Receipts/Municipal Utility Tax	6,656	(101.02)	(0.27677)	(1,842)	NS-PGL Ex. 27.10N, p. 1, Line 22
23	Energy Assistance Charges	1,777	(60.05)	(0.16452)	(292)	NS-PGL Ex. 27.10N, p. 1, Line 23
24	IDOR Gas Revenue/Public Utility tax	7,218	(31.06)	(0.08510)	(614)	NS-PGL Ex. 27.10N, p. 1, Line 24
25	-	-	-	-	-	
26	Interest Expense	4,190	(91.25)	(0.25000)	(1,048)	ICC Staff Ex. 11.0, Sch. 11.06N, Line 3
27	Federal Income Tax	5,546	(37.88)	(0.10378)	(576)	ICC Staff Ex. 11.0, Sch. 11.01N, Line 20
28	State Income Tax	1,340	(37.88)	(0.10378)	(139)	ICC Staff Ex. 11.0, Sch. 11.01N, Line 19
29	Total	$ 187,203			$ (21,252)	Sum of Lines 4 through 28
30	Cash Working Capital per Staff				$ (2,239)	Line 3 + Line 29
31	Cash Working Capital per Company				(60)	NS-PGL Ex. 27.10N, p. 1, Line 28
32	Difference -- Staff Adjustment				$ (2,179)	Line 30 - Line 31

Note: Lag (Lead) is from PGL Ex. 7.1, p. 14; except for lines 2 and 8
Line 2 lag: ICC Staff Ex. 12.0, p. 17
Line 8 lead: Staff Data Request DGK-13.03

North Shore Gas Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No. (A)	Description (B)	Amount (C)	Source (D)
1	Total Operating Revenues	$ 82,039	ICC Staff Ex. 11.0, Sch. 11.01N, Column I, Line 5
2	PGA Revenue	109,510	NS-PGL Ex. 27.10N, p. 1, Line 7
3	Uncollectible Accounts	(784)	ICC Staff Ex. 11.0, Sch. 11.01N, Column I, Line 6
4	Depreciation & Amortization	(10,768)	ICC Staff Ex. 11.0, Sch. 11.01N, Column I, Line 15
5	Deferred Taxes and ITCs Net	497	ICC Staff Ex. 11.0, Sch. 11.01N, Column I, Line 21
6	Return on Equity	(9,140)	Line 10 below
7	Total Revenues for CWC calculation	$ 171,354	Sum of Lines 1 through 6
8	Total Rate Base	$ 200,484	ICC Staff Ex. 11.0, Sch. 11.03N, p. 1, Line 23
9	Weighted Cost of Capital	4.56%	ICC Staff Ex. 15.0, Schedule 15.01
10	Return on equity deduction from revenue	$ 9,140	Line 8 x Line 9
11	O & M Expenses	$ 62,320	ICC Staff Ex. 11.0, Sch. 11.01N, Column I, Line 18
12	Payroll and Withholdings	(9,012)	ICC Staff Ex. 12.0, Sch. 12.03N, p. 3, Line 3
13	Incentive Pay	(170)	NS-PGL Ex. 27.10N, p. 1, Line 5
14	Inter-Company Billings	(30,239)	NS-PGL Ex. 27.10N, p. 1, Line 6
15	Pension and OPEB	(4,720)	NS-PGL Ex. 27.10N, p. 1, Line 8
16	Other Benefits	(1,968)	NS-PGL Ex. 27.10N, p. 1, Line 9
17	FICA	(595)	ICC Staff Ex. 12.0, Sch. 12.03N, p. 3, Line 9
18	Taxes Other Than Income excluding FICA	(1,729)	ICC Staff Ex. 12.0, Sch. 12.03N, Sum of Lines 12 through 20
19	Uncollectible Accounts	(784)	ICC Staff Ex. 11.0, Sch. 11.01N, Column I, Line 6
20	Depreciation & Amortization	(10,768)	ICC Staff Ex. 11.0, Sch. 11.01N, Column I, Line 15
21	Other Operations & Maintenance	$ 2,335	Sum of Lines 11 through 20

North Shore Gas Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No. (A)	Description (B)	Amount (C)	Source (D)
1	Payroll and Withholdings per Company Filing	$ 9,396	NS-PGL Ex. 27.10N, p. 2, Line 36
2	Non-Union Wages Adjustment	(384)	ICC Staff Ex. 13.0, Sch. 13.02N; excluding FICA (see line 8)
3	Payroll and Withholdings per Staff	$ 9,012	Sum of Lines 1 and 2
4	Invested Capital Tax per Company Filing	$ 1,439	NS-PGL Ex. 27.10N, p. 2, Line 23
5	Invested Capital Tax Adjustment	(34)	ICC Staff Ex. 14.0, Sch. 14.03N
6	Invested Capital Tax per Staff	$ 1,405	Sum of Lines 4 and 5
7	FICA per Company	629	NS-PGL Ex. 27.10N, p. 2, Line 39
8	Non-Union Wages Adjustment	(34)	ICC Staff Ex. 13.0, Sch. 13.02N
9	FICA per Staff	$ 595	Sum of Lines 7 and 8

North Shore Gas Company
Customer Deposits Interest Adjustment
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description	Amount	Source
(A)	(B)	(C)	(D)
1	Interest on Customer Deposits per Staff	$ -	Ex. 12.0, p. 24
2	Interest on Customer Deposits per Company	12	Co. Sch. B-13
3	Staff Adjustment to Interest on Customer Deposits	$ (12)	Line 1 - Line 2

North Shore Gas Company
Budget Payment Plan Interest Adjustment
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description	Amount	Source
(A)	(B)	(C)	(D)
1	Interest on Budget Payment Plans per Staff	$ -	Ex. 12.0, p. 24
2	Interest on Budget Payment Plans per Company	13	Co. Sch. B-14
3	Staff Adjustment to Interest on Budget Payment Plans	$ (13)	Line 1 - Line 2

North Shore Gas Company
Alternate Gross Utility Plant Additions Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description		Amount	Source
(A)	(B)		(C)	(D)
1	Staff Adjustment to Utility Plant-in-Service	$	(2,403)	ICC Staff Ex. 12.0, Sch. 12.06N, p. 2, Colm. F, Line 15
2	Staff Adjustment to Depreciation Expense	$	(17)	ICC Staff Ex. 12.0, Sch. 12.06N, p. 2, Colm. K, Line 15
3	Staff Adjustment to Accumulated Depreciation	$	17	- ICC Staff Ex. 12.0, Sch. 12.06N, p. 2, Colm. K, Line 15
4	Staff Adjustment to Accumulated Deferred Taxes	$	15	= - ICC Staff Ex. 12.0, Sch. 12.06N, p. 2, Colm. N, Line 15 - ICC Staff Ex. 12.0, Sch. 12.06N, p. 2, Colm. O, Line 15 - ICC Staff Ex. 12.0, Sch. 12.06N, p. 3, Colm. F, Line 15

North Shore Gas Company

Alternate Gross Utility Plant Additions Adjustments

For the Test Year Ending December 31, 2013

(In Thousands)

Line No.	Item	Depr Method	2013 Gross Additions less Retirements	Projected Additions per Staff	Staff Adjustment	Book Depr %
(A)	(B)	(C)	(D)	(E)	(F)	(G)
				89.21 %	12.02N p. 4	
			Co. Sch. B-5	(D* 89.21%)	(E - D)	
1	Distribution	Macrs 15	18,867	16,831	(2,036)	2.4500%
2	Underground Storage	Macrs 15	0	0	0	1.1500%
3	Liquefied Natural Gas	Macrs 15	0	0	0	0.0000%
4	Transmission - Not Leased	Macrs 15	3,000	2,676	(324)	1.8300%
5	General	Macrs 5	1,319	1,177	(142)	7.1300%
6	Intangible	SL 3	0	0	0	0.0000%
7	Production	Macrs 7	75	67	(8)	1.1200%
8	ARO Obligation	Zero	0	0	0	0.0000%
9	Total Account 101		23,261	20,751	(2,510)	
10						
11	Recoverable Natural Gas (Account 117)	Zero	0	0	0	0.0000%
12	Total Plant in Service		23,261	20,751	(2,510)	
13	Construction Work in Progress (Account 107)	Zero	(1,000)	(892)	108	0.0000%
14						
15	Total Utility Plant		22,261	19,858	(2,403)	

North Shore Gas Company

Alternate Gross Utility Plant Additions Adjustments

For the Test Year Ending December 31, 2013

(In Thousands)

Tax Depr %	Federal Tax Depr	State Tax Depr	Book Depreciation	Federal M1	State M1	2013 Federal Def Tax	2013 State Def Tax	Line
(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	(F * H) / 2	(F * H) / 2	(F * G) / 2	(I - K)	(J - K)	(L * 35%)	(M * 9.5%)	
3.7500%	(38)	(38)	(13)	(26)	(26)	(9)	(2)	1
5.0000%	0	0	0	0	0	0	0	2
0.0000%	0	0	0	0	0	0	0	3
5.0000%	(8)	(8)	(2)	(7)	(7)	(2)	(1)	4
20.0000%	(14)	(14)	(3)	(12)	(12)	(4)	(1)	5
0.0000%	0	0	0	0	0	0	0	6
3.7500%	0	0	0	0	0	0	0	7
0.0000%	0	0	0	0	0	0	0	8
	(60)	(60)	(17)	(44)	(44)	(15)	(4)	9
								10
0.0000%	0	0	0	0	0	0	0	11
	(60)	(60)	(17)	(44)	(44)	(15)	(4)	12
0.0000%	0	0	0	0	0	0	0	13
								14
	(60)	(60)	(17)	(44)	(44)	(15)	(4)	15

North Shore Gas Company
Alternate Gross Utility Plant Additions Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description	Days(1)	Ratio	Liberalized Depreciation Statutory Rate: Per Staff	Liberalized Depreciation Statutory Rate: Prorated	Source
[A]	[B]	[C]	[D]	[E]	[F]	(G)
1	2013 Additions Adjustment - Federal Deferred Tax			$ (15)		ICC Staff Ex. 12.0, Sch. 12.06N, p. 2, Colm. N, Line 15
			(C/D 16)		(D * E)	
2	January		100.0%	(1)	(1)	
3	February		100.0%	(1)	(1)	
4	March		100.0%	(2)	(2)	
5	April		100.0%	(1)	(1)	
6	May		100.0%	(1)	(1)	
7	June		100.0%	(2)	(2)	
8	July	154	83.2%	(1)	(1)	
9	August	123	66.5%	(1)	(1)	
10	September	93	50.3%	(2)	(1)	
11	October	62	33.5%	(1)	0	
12	November	32	17.3%	(1)	0	
13	December	1	0.5%	(1)	0	
14	Total 12/31/2013			$ (15)	$ (11)	
15	Impact of Proration				$ 4	
16	Notes: (1)Total days in period:		185			

Assumes rates become effective July 1, 2013.

Peoples Gas Light and Coke Company

Average Rate Base Adjustments

For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description	Gross Utility Plant	Accumulated Depreciation	ADIT	Net Retirement Benefits	Reserve for Injuries & Damages	Total Rate Base Adjustments	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) Sum C thru G	(I)
1	2013 Beginning Gross Plant	$ 2,957,595	$ (1,160,233)	$ (526,974)	$ 88,868	$ (9,206)	$ 1,350,050	PGL Ex. 19.1
2	2013 Average Gross Plant	3,106,341	(1,191,787)	(518,584)	68,943	(9,077)	$ 1,455,836	(Line 1 + Line 3) / 2
3	2013 Year-End Gross Plant	3,255,086	(1,223,340)	(510,194)	49,017	(8,947)	1,561,622	NS-PGL 27.1P
4	Staff Adjustments	$ (148,746)	$ 31,554	$ (8,390)	$ 19,926	$ (130)	$ (105,786)	Line 2 - Line 3

The Peoples Gas Light and Coke Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Item	Amount	Lag (Lead)	CWC Factor (D) / 365	CWC Requirement (C) x (E)	Column (C) Source
(A)	(B)	(C)	(D)	(E) (D/365)	(F)	(G)
1	Revenues	$ 865,998	49.59	0.13586	$ 117,657	ICC Staff Ex. 12.0, Sch. 12.03P, p. 2, Line 7
2	Pass Through Taxes	161,779	0.00	0.00000	-	Sum of lines 21 - 25 below
3	Total	$ 1,027,777			$ 117,657	Line 1 + Line 2
4	Payroll and Withholdings	$ 69,011	(14.30)	(0.03918)	(2,704)	ICC Staff Ex. 12.0, Sch. 12.03P, p. 3, Line 3
5	Incentive Pay	2,126	(250.50)	(0.68630)	(1,459)	NS-PGL Ex. 27.10P, p. 1, Line 5
6	Inter Company Billings	137,361	(35.23)	(0.09652)	(13,258)	ICC Staff Ex. 12.0, Sch. 12.03P, p. 3, Line 12
7	Natural Gas	473,189	(40.48)	(0.11090)	(52,479)	NS-PGL Ex. 27.10P, p. 1, Line 7
8	Pension and OPEB	35,811	(35.23)	(0.09652)	(3,456)	NS-PGL Ex. 27.10P, p. 1, Line 8
9	Other Benefits	13,896	(40.31)	(0.11044)	(1,535)	NS-PGL Ex. 27.10P, p. 1, Line 9
10	Other Operations and Maintenance	48,820	(43.63)	(0.11953)	(5,836)	ICC Staff Ex. 12.0, Sch. 12.03P, p. 2, Line 21
11	Federal Insurance Contributions (FICA)	4,249	(16.29)	(0.04463)	(190)	ICC Staff Ex. 12.0, Sch. 12.03P, p. 3, Line 9
12	Federal Unemployment Tax	18	(60.88)	(0.16679)	(3)	NS-PGL Ex. 27.10P, p. 1, Line 13
13	State Unemployment Tax	250	(71.33)	(0.19542)	(49)	NS-PGL Ex. 27.10P, p. 1, Line 14
14	Property/Real Estate Taxes	1,078	(373.16)	(1.02236)	(1,102)	NS-PGL Ex. 27.10P, p. 1, Line 15
15	Invested Capital Tax	10,936	(30.38)	(0.08323)	(910)	ICC Staff Ex. 12.0, Sch. 12.03P, p. 3, Line 6
16	Corporation Franchise Tax	219	(185.95)	(0.50945)	(112)	NS-PGL Ex. 27.10P, p. 1, Line 17
17	Sales, Use and Accelerated Tax	181	(20.11)	(0.05510)	(10)	NS-PGL Ex. 27.10P, p. 1, Line 18
18	Federal Excise Tax	59	(76.38)	(0.20926)	(12)	NS-PGL Ex. 27.10P, p. 1, Line 19
19	Chicago Employer's Expense Tax	65	(60.82)	(0.16663)	(11)	NS-PGL Ex. 27.10P, p. 1, Line 20
20	Unauthorized Insurance Tax	144	155.18	0.42515	61	NS-PGL Ex. 27.10P, p. 1, Line 21
21	ICC Gas Revenue Tax	1,058	34.59	0.09477	100	NS-PGL Ex. 27.10P, p. 1, Line 23
22	Gross Receipts/Municipal Utility Tax	84,618	(73.79)	(0.20216)	(17,107)	NS-PGL Ex. 27.10P, p. 1, Line 24
23	Energy Assistance Charges	9,690	(67.95)	(0.18616)	(1,804)	NS-PGL Ex. 27.10P, p. 1, Line 25
24	IDOR Gas Revenue/Public Utility Tax	34,771	(38.96)	(0.10674)	(3,711)	NS-PGL Ex. 27.10P, p. 1, Line 26
25	City of Chicago Gas Use tax	31,642	(73.90)	(0.20247)	(6,406)	NS-PGL Ex. 27.10P, p. 1, Line 27
26	Interest Expense	25,661	(91.25)	(0.25000)	(6,415)	ICC Staff Ex. 11.0, Sch. 11.06P, Line 3
27	Federal Income Tax	35,369	(37.88)	(0.10378)	(3,671)	ICC Staff Ex. 11.0, Sch. 11.01P, Line 20
28	State Income Tax	7,555	(37.88)	(0.10378)	(784)	ICC Staff Ex. 11.0, Sch. 11.01P, Line 19
29	Total	$ 1,027,777			$ (122,863)	Sum of Lines 4 through 28
30	Cash Working Capital per Staff				$ (5,206)	Line 3 + Line 29
31	Cash Working Capital per Company				21,197	NS-PGL Ex. 27.10P, p. 1, Line 31
32	Difference -- Staff Adjustment				$ (26,403)	Line 30 - Line 31

Note: Lag (Lead) is from NS-PGL Ex. 27.10P, p. 1; except for lines 2 and 8
Line 2 lag: ICC Staff Ex. 12.0, p. 17
Line 8 lead: Staff Data Request DGK-13.03

The Peoples Gas Light and Coke Company

Cash Working Capital Adjustments

For the Test Year Ending December 31, 2013

(In Thousands)

Line No. (A)	Description (B)	Amount (C)		Source (D)
1	Total Operating Revenues	$	562,184	ICC Staff Ex. 11.0, Sch. 11.01P, Column I, Line 5
2	PGA Revenue		473,189	NS-PGL Ex. 27.10P, p. 1, Line 7
3	Uncollectible Accounts		(18,708)	ICC Staff Ex. 11.0, Sch. 11.01P, Column I, Line 6
4	Depreciation & Amortization		(93,941)	ICC Staff Ex. 11.0, Sch. 11.01P, Column I, Line 15
5	Deferred Taxes and ITCs Net		1,248	ICC Staff Ex. 11.0, Sch. 11.01P, Column I, Line 21
6	Return on Equity		(57,974)	Line 10 below
7	Total Revenues for CWC calculation	$	865,998	Sum of Lines 1 through 6
8	Total Rate Base	$	1,267,192	ICC Staff Ex. 11.0, Sch. 11.03P, p. 1, Line 23
9	Weighted Cost of Capital		4.575%	ICC Staff Ex. 15.0, Schedule 15.01
10	Return on equity deduction from revenue	$	57,974	Line 8 x Line 9
11	O & M Expenses	$	436,873	ICC Staff Ex. 11.0, Sch. 11.01P, Column I, Line 18
12	Payroll and Withholdings		(69,011)	ICC Staff Ex. 12.0, Sch. 12.03P, p. 3, Line 3
13	Incentive Pay		(2,126)	NS-PGL Ex. 27.10P, p. 1, Line 5
14	Inter-Company Billings		(137,361)	ICC Staff Ex. 12.0, Sch. 12.03P, p. 3, Line 12
15	Pension and OPEB		(35,811)	NS-PGL Ex. 27.10P, p. 1, Line 8
16	Other Benefits		(13,896)	NS-PGL Ex. 27.10P, p. 1, Line 9
17	FICA		(4,249)	ICC Staff Ex. 12.0, Sch. 12.03P, p. 3, Line 9
18	Taxes Other Than Income excluding FICA		(12,950)	ICC Staff Ex. 12.0, Sch. 12.03P, Sum of Lines 12 through 20
19	Uncollectible Accounts		(18,708)	ICC Staff Ex. 11.0, Sch. 11.01P, Column I, Line 6
20	Depreciation & Amortization		(93,941)	ICC Staff Ex. 11.0, Sch. 11.01P, Column I, Line 15
21	Other Operations & Maintenance	$	48,820	Sum of Lines 11 through 20

The Peoples Gas Light and Coke Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2013
(In Thousands)

Line No. (A)	Description (B)	Amount (C)	Source (D)
1	Payroll and Withholdings per Company Filing	$ 74,168	NS-PGL Ex. 27.10P, p. 2, Line 39
2	Non-Union Wages Adjustment	(5,157)	ICC Staff Ex. 13.0, Sch. 13.02P; Excluding FICA (see line 8)
3	Payroll and Withholdings per Staff	$ 69,011	Sum of Lines 1 and 2
4	Invested Capital Tax per Company Filing	$ 11,358	NS-PGL Ex. 27.10P, p. 2, Line 22
5	Invested Capital Tax Adjustment	(422)	ICC Staff Ex. 14.0, Sch. 14.03N
6	Invested Capital Tax per Staff	$ 10,936	Sum of Lines 4 and 5
7	FICA per Company	4,729	NS-PGL Ex. 27.10P, p. 2, Line 42
8	Non-Union Wages Adjustment	(480)	ICC Staff Ex. 13.0, Sch. 13.03P
9	FICA per Staff	$ 4,249	Sum of Lines 7 and 8
10	Intercompany Charges per Company	$ 149,688	NS-PGL Ex. 27.10P, p. 2, Line 35
11	Intercompany Charges Tax Adjustment	(12,327)	ICC Staff Ex. 14.0, Sch. 14.02P
12	Intercompany Charges Tax per Staff	$ 137,361	Sum of Lines 10 and 11

Peoples Gas Light and Coke Company
Customer Deposits Interest Adjustment
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description	Amount	Source
(A)	(B)	(C)	(D)
1	Interest on Customer Deposits per Staff	$ -	Ex. 12.0, p. 24
2	Interest on Customer Deposits per Company	140	Co. Sch. B-13
3	Staff Adjustment to Interest on Customer Deposits	$ (140)	Line 1 - Line 2

Peoples Gas Light and Coke Company
Budget Payment Plan Interest Adjustment
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description	Amount	Source
(A)	(B)	(C)	(D)
1	Interest on Budget Payment Plans per Staff	$ -	Ex. 12.0, p. 24
2	Interest on Budget Payment Plans per Company	64	Co. Sch. B-14
3	Staff Adjustment to Interest on Budget Payment Plans	$ (64)	Line 1 - Line 2

Peoples Gas Light and Coke Company
Adjustments Sponsored by Staff Witness Seagle
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description		Amount	Source
(A)	(B)		(C)	(D)
1	Staff Adjustment to Utility Plant-in-Service	$	(183,054)	ICC Staff Ex. 12.0, Sch. 12.07P, p. 2, Colm. D, Line 9
2	Staff Adjustment to Depreciation Expense	$	(3,084)	ICC Staff Ex. 12.0, Sch. 12.07P, p. 2, Colm. I, Line 9
3	Staff Adjustment to Accumulated Depreciation	$	3,898	ICC Staff Ex. 12.0, Sch. 12.07P, p. 2, Colm. I, Line 9 includes one-half of ICC Staff Ex. 12.0, Sch. 12.07P, p. 2, Colm. I, Lines 6 & 7 for 2012 depreciation
4	Staff Adjustment to Accumulated Deferred Taxes	$	1,299	= - ICC Staff Ex. 12.0, Sch. 12.07P, p. 2, Colm. L, Line 9 - ICC Staff Ex. 12.0, Sch. 12.07P, p. 2, Colm. M, Line 9 - ICC Staff Ex. 12.0, Sch. 12.07P, p. 3, Colm. F, Line 9

Peoples Gas Light and Coke Company
Adjustments Sponsored by Staff Witness Seagle
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Item	Depr Method	Staff Adjustment	Book Depr %	Tax Depr %	Federal Tax Depr	State Tax Depr	Book Depreciation	Federal M1	State M1	2013 Federal Def Tax	2013 State Def Tax
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			ICC Staff Ex. 16.0 *	Co. Sch C-12, p. 4	Staff DR DGK-11.02	(D * F)	(D * F)	(D * E)	(G - I)	(H - I)	(J * 35%)	(K * 9.5%)
1						0	0	0	0	0	0	0
2						0	0	0	0	0	0	0
3	Calumet System Upgrade	Macrs 20	(25,000)	3.3700%	3.7500%	(938)	(938)	(421)	(517)	(517)	(181)	(49)
4						0	0	0	0	0	0	0
5						0	0	0	0	0	0	0
6	CNG Fueling Station at Division Street Shop - 2012	Macrs 20	(858)	3.3700%	3.7500%	(32)	(32)	(14)	(18)	(18)	(6)	(2)
7	Accelerated Main Replacement Program - 2012	Macrs 20	(95,794)	3.3700%	3.7500%	(3,592)	(3,592)	(1,614)	(1,978)	(1,978)	(692)	(188)
8	Accelerated Main Replacement Program - 2013	Macrs 20	(61,402)	3.3700%	3.7500%	(2,303)	(2,303)	(1,035)	(1,268)	(1,268)	(444)	(120)
9	Total Utility Plant		(183,054)			(6,865)	(6,865)	(3,084)	(3,781)	(3,781)	(1,323)	(359)

* Adjustment divided by two to accommodate average rate base except Lines 6 & 7 which are for 2012

Peoples Gas Light and Coke Company
Adjustments Sponsored by Staff Witness Seagle
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description	Days(1)	Ratio	Liberalized Depreciation Statutory Rate: Per Staff	Liberalized Depreciation Statutory Rate: Prorated	Source
[A]	[B]	[C]	[D]	[E]	(F)	(G)
1	2013 Additions Adjustment - Federal Deferred Tax			$ (1,323)		ICC Staff Ex. 12.0, Sch. 12.07P, p. 2, Colm. L, Line 15
			(C/D 16)		(D * E)	
2	January		100.0%	(110)	(110)	
3	February		100.0%	(110)	(110)	
4	March		100.0%	(111)	(111)	
5	April		100.0%	(110)	(110)	
6	May		100.0%	(110)	(110)	
7	June		100.0%	(111)	(111)	
8	July	154	83.2%	(110)	(92)	
9	August	123	66.5%	(110)	(73)	
10	September	93	50.3%	(111)	(56)	
11	October	62	33.5%	(110)	(37)	
12	November	32	17.3%	(110)	(19)	
13	December	1	0.5%	(110)	(1)	
14	Total 12/31/2013			$ (1,323)	$ (940)	
15	Impact of Proration				$ 383	
16	Notes: (1)Total days in period:		185			

Assumes rates become effective July 1, 2013.

Peoples Gas Light and Coke Company
Alternate Adjustments Sponsored by Staff Witness Seagle
For the Test Year Ending December 31, 2013
(In Thousands)

Line No. (A)	Description (B)		Amount (C)	Source (D)
1	Staff Adjustment to Utility Plant-in-Service	$	(269,456)	ICC Staff Ex. 12.0, Sch. 12.08P, p. 2, Colm. D, Line 9
2	Staff Adjustment to Depreciation Expense	$	(3,084)	ICC Staff Ex. 12.0, Sch. 12.08P, p. 2, Colm. I, Line 9
3	Staff Adjustment to Accumulated Depreciation	$	3,898	ICC Staff Ex. 12.0, Sch. 12.08P, p. 2, Colm. I, Line 9 includes one-half of ICC Staff Ex. 12.0, Sch. 12.08P, p. 2, Colm. I, Lines 6 & 7 for 2012 depreciation
4	Staff Adjustment to Accumulated Deferred Taxes	$	1,298	= - ICC Staff Ex. 12.0, Sch. 12.08P, p. 2, Colm. L, Line 9 - ICC Staff Ex. 12.0, Sch. 12.08P, p. 2, Colm. M, Line 9 - ICC Staff Ex. 12.0, Sch. 12.08P, p. 3, Colm. F, Line

Peoples Gas Light and Coke Company
Alternate Adjustments Sponsored by Staff Witness Seagle
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Item	Depr Method	Staff Adjustment	Book Depr %	Tax Depr %	Federal Tax Depr *	State Tax Depr *	Book Depreciation *	Federal M1	State M1	2013 Federal Def Tax	2013 State Def Tax
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			ICC Staff Ex. 16.0 *	Co. Sch C-12, p. 4	Staff DR DGK-11.02	(D * F) / 2	(D * F) / 2	(D * E) / 2	(G - I)	(H - I)	(J * 35%)	(K * 9.5%)
1						0	0	0	0	0	0	0
2						0	0	0	0	0	0	0
3	Calumet System Upgrade	Macrs 20	(50,000)	3.3700%	3.7500%	(938)	(938)	(422)	(516)	(516)	(181)	(49)
4						0	0	0	0	0	0	0
5						0	0	0	0	0	0	0
6	CNG Fueling Station at Division Street Shop - 2012	Macrs 20	(858)	3.3700%	3.7500%	(32)	(32)	(14)	(18)	(18)	(6)	(2)
7	Accelerated Main Replacement Program - 2012	Macrs 20	(95,794)	3.3700%	3.7500%	(3,592)	(3,592)	(1,614)	(1,978)	(1,978)	(692)	(188)
8	Accelerated Main Replacement Program - 2013	Macrs 20	(122,804)	3.3700%	3.7500%	(2,303)	(2,303)	(1,035)	(1,268)	(1,268)	(444)	(120)
9	Total Utility Plant		(269,456)			(6,864)	(6,864)	(3,084)	(3,780)	(3,780)	(1,323)	(359)

* 2012 depreciation not divided by two to reflect a full year of depreciation

Peoples Gas Light and Coke Company
Alternate Adjustments Sponsored by Staff Witness Seagle
For the Test Year Ending December 31, 2013
(In Thousands)

Line No.	Description	Days(1)	Ratio	Liberalized Depreciation Statutory Rate Per Staff	Prorated	Source
[A]	[B]	[C]	[D]	[E]	(F)	(G)
1	2013 Additions Adjustment - Federal Deferred Tax			$ (1,323)		ICC Staff Ex. 12.0, Sch. 12.08P, p. 2, Colm. L, Line 15
			(C/D 16)		(D * E)	
2	January		100.0%	(110)	(110)	
3	February		100.0%	(111)	(111)	
4	March		100.0%	(110)	(110)	
5	April		100.0%	(110)	(110)	
6	May		100.0%	(110)	(110)	
7	June		100.0%	(111)	(111)	
8	July	154	83.2%	(110)	(92)	
9	August	123	66.5%	(110)	(73)	
10	September	93	50.3%	(110)	(55)	
11	October	62	33.5%	(111)	(37)	
12	November	32	17.3%	(110)	(19)	
13	December	1	0.5%	(110)	(1)	
14	Total 12/31/2013			(1,323)	$ (939)	
15	Impact of Proration				$ 384	
16	Notes: (1)Total days in period:		185			

Assumes rates become effective July 1, 2013.