SC St. No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

DIRECT TESTIMONY OF

EZRA D. HAUSMAN, PH.D.

ON BEHALF OF
THE SIERRA CLUB AND CLEAN AIR COUNCIL

Docket No. R-2020-3017206

Philadelphia Gas Works

General Rate Increase Request

June 15, 2020

Table of Contents

ATTACHED EXHIBITS

Exhibit EDH-1	Resume of Ezra D. Hausman, Ph.D.
Exhibit EDH-2	Jim Lazar et al., *Smart Rate Design for a Smarter Future, Appendix D: The Specter of Straight Fixed/Variable Rate Designs and the Exercise of Monopoly Power*, Regulatory Assistance Project (Aug. 31, 2015).
Exhibit EDH-3	Ben Strauss et al,. *Pennsylvania and the Surging Sea: A vulnerability assessment with projections for sea level rise and coastal flood risk*, Climate Central (July 2016).
Exhibit EDH-4	Petition of the Office of the Massachusetts Attorney General Requesting an Investigation into the impact on the continuing business operations of local gas distribution companies as the Commonwealth achieves its 2050 Climate Limits (June 4, 2020).
Exhibit EDH-5	Case No. 17-G-0460, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan, New York State Department of Public Service, (June 14, 2018).
Exhibit EDH-6	Case No. 17-G-0460, Central Hudson Gas & Electric Corporation's Non-Pipeline Alternatives Annual Report, Central Hudson Gas & Electric Corporation (Dec. 2, 2019).
Exhibit EDH-7	PGW Responses to Clean Air Council Discovery Requests CAC-01-CAC-01-5, CAC-01-CAC-01-6 (June 10, 2020).
Exhibit EDH-8	Case No. 14-0224, Order, pgs. 158–176, Illinois Commerce Commission (Jan. 21, 2015).

I. Professional Qualifications

Q. Please state your name, occupation, and business address.

A. My name is Ezra D. Hausman, Ph.D. I am an independent consultant doing business as Ezra Hausman Consulting, operating from offices at 77 Kaposia Street, Auburndale, Massachusetts 02466.

Q. What is your professional and educational background?

A. I have served as an independent consulting analyst and expert in energy and environmental issues since 2014. Before that, from 2005 until early 2014, I was employed at Synapse Energy Economics, Inc., a research and consulting company located in Cambridge, Massachusetts, where I served as Vice President, and Chief Operating Officer. At Synapse, and continuing as an independent consultant, I served as an analyst and expert in several areas, including: state and regional energy, capacity, and transmission planning, including both utility resource planning and long-term (multi-decadal) climate-constrained resource planning; regulatory and ratemaking proceedings; electricity and generating capacity market design and analysis; electric system dispatch modeling; economic analysis of environmental and other regulations, including greenhouse gas regulation, in energy markets; economic analysis, price forecasting, and asset valuation; quantification of the economic and environmental benefits of displaced emissions; energy efficiency and renewable energy programs and policies; and regulation and mitigation of greenhouse gas emissions.

I have provided testimony before public utility commissions or legislative committees in Arizona, Florida, Illinois, Indiana, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, Nevada, New Hampshire, New Jersey, North Carolina, Oregon, South Carolina, South Dakota, Utah, Vermont, Virginia, Washington, DC, and Washington State, as well as at the Federal level. I have provided expert representation for stakeholders at the PJM ISO, the California ISO, the Midcontinent ISO, and at the Federal Energy Regulatory Commission ("FERC"). While most of my testimony and analytical work has centered on issues in electricity market economics, I have also brought my expertise as a scientist to bear on cases involving greenhouse gas regulation and mitigation in the United States.

Before joining Synapse, I was employed from 1998 through 2004 as a Senior Associate at Tabors Caramanis and Associates ("TCA") of Cambridge, Massachusetts. In 2004, TCA was acquired by Charles River Associates ("CRA"), where I remained until I joined Synapse in 2005. At TCA/CRA, I performed a wide range of electricity market and economic analyses and price forecast modeling studies. These included asset valuation studies, market transition cost/benefit studies, market power analyses, and litigation support. I have extensive experience with market simulation, production cost modeling, and resource planning methodologies and software.

I hold a BA in Psychology from Wesleyan University, an MS in Environmental Engineering from Tufts University, an SM in Applied Physics from Harvard University, and a PhD in Atmospheric Chemistry from Harvard University. I have provided a detailed resume as Exhibit EDH-1.

Q. Have you testified previously before the Pennsylvania Public Utility Commission?

A. No.

II. Scope of Testimony and Recommendations to the Commission

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

A. I am providing testimony on the recent rate increase filing ("Rate Increase Filing") by Philadelphia Gas Works ("PGW" or the "Company") for both an increase in annual rate base of $70 million,[1] 84% of which would come from residential customers;[2] along with a 40% increase in its monthly customer charge for almost every rate class, including residential customers.[3] I address both elements of the Company's proposal in the context of the need to dramatically reduce greenhouse gas emissions in Philadelphia. I also show that the increased customer charge is not justified by economic theory, would be detrimental to customer welfare, and would compromise customers' incentives to make wise energy choices.

Q. What are your recommendations for this Commission?

A. I make the following recommendations:

1. I recommend that the Commission find that the Company has inadequately studied potential cost-effective alternatives to its proposed infrastructure work (such as energy efficiency ~~and electrification~~) and has inadequately considered climate trends in its infrastructure planning, creating a likelihood of future stranded assets. As a result, I recommend that the Commission find that the Company has failed to demonstrate that its proposed investments are necessary, reasonable, or prudent. To

---

[1] PGW 2020 Rate Filing, Vol. II, *Direct Testimony of Gregory Stunder* at 2:1, Docket No. R-2020-3017206 (Feb. 28, 2020) ("PGW St. No. 1").

[2] PGW 2020 Rate Filing, Vol. II, *Direct Testimony of Kenneth S. Dybalski* at 8, Docket No. R-2020-3017206 (Feb. 28, 2020) ("PGW St. No. 6").

[3] *Id.* at 7.

redress these deficiencies, and to provide the Commission with the necessary information to determine whether or not the Company's proposed rate increase is just and reasonable, the Commission should direct the Company to produce a Climate Business Plan ("CBP"). The CBP, which should include consideration of potentially cost-effective alternatives to maintaining or expanding the Company's gas infrastructure, such as energy efficiency ~~and electrification~~, should serve as a roadmap for infrastructure planning that is consistent with climate trends and consistent with the goals set forth by Governor Wolf and the Philadelphia City Council to aggressively reduce and ultimately eliminate greenhouse gas emissions in the Commonwealth of Pennsylvania and the City of Philadelphia.

2. I recommend that the Commission deny PGW's requested rate increase pending completion of its CBP and a finding by the Commission that (a) the CBP is consistent with the demonstrated need to reduce greenhouse gas emissions, and (b) that PGW's request is consistent with the actions set forth in the CBP. If necessary, the Commission could approve a narrowly tailored exception for safety-related distribution system maintenance and addressing major gas leakage, but even in these cases the Company should be directed to first investigate the potential for non-pipeline alternatives.

3. Whether or not the Commission approves PGW's overall requested rate increase, I recommend that the Commission reject PGW's proposal to increase its fixed customer charge, which would be harmful to low-income customers and at cross-purposes with energy efficiency initiatives. The Company should be directed to build any approved rate increase into the volumetric charge for all customer classes.

III. Issues with the PGW Rate Increase Filing

Q. What has PGW requested in its Rate Increase Filing, in the areas you wish to address?

A. PGW has requested "an increase in its annual rate base operating revenues of $70 million, or 10.5% on a total revenue basis with a proposed effective date of April 28, 2020."[4] PGW has also proposed to restructure its rates, and particularly its residential rates, to rely more heavily on a fixed per-customer charge, and less on volumetric rates.[5]

Q. Why has PGW requested a rate increase at this time?

A. According to PGW witness Gregory Stunder, the Company has made numerous investments in its infrastructure and in improving customer service since 2017. Mr. Stunder explains that PGW also experienced "increases in pension costs, post-retirement benefit costs, capital spending and debt service."[6] Although as a municipal utility PGW does not have to offer a return on shareholder capital, it does rely in part on debt financing for its infrastructure spending. Mr. Stunder states that the proposed rate increase would help to "maintain[] its financial metrics and current financial position so that it can maintain access to, and improve its borrowing costs for long-term bond transactions and access to credit facilities."[7]

Q. Do you agree that PGW's proposed rate increase is necessary at this time?

A. I certainly agree that it is important for PGW to ensure customer safety and reduce gas

---

[4] PGW St. No. 1 at 2:1–3.
[5] PGW St. No. 6 at 6–8
[6] PGW St. No. 1 at 3:12–18.
[7] *Id.* at 3:19–21.

leakage. Methane is a powerful greenhouse gas, and it also has direct deleterious effects on human health and the environment. I also agree that it is important for the Company to maintain strong financial metrics so that it can continue to access credit on favorable terms.

However, I have two significant concerns with PGW's request. First, any such request should be reviewed by this Commission in the context of the need to significantly reduce use of fossil fuels over the next several years that has been conclusively demonstrated by innumerable scientific studies, many of which are documented by the Intergovernmental Panel on Climate Change.[8] The Company does not appear to have considered how its operations should be modified as the City of Philadelphia, the Commonwealth of Pennsylvania, and the United States transition from an unsustainable fossil fuel-based economy to an economy powered by carbon-free energy sources. PGW should not be permitted to continue indefinitely investing in infrastructure that is incompatible with a climate-constrained future.

Second, PGW has proposed an overly-burdensome increase in fixed charges, especially for residential customers, as part of its proposed rate increase. Reliance on fixed charges is detrimental to customers because it reduces the opportunity for bill reduction through energy savings, including through participation in PGW's own EnergySense efficiency program. It is particularly harmful to low-income customers who tend to use less gas than

[8] *See* Working Group I, *AR6 Climate Change 2021: The Physical Science Basis*, IPCC Sixth Assessment Report, https://www.ipcc.ch/report/sixth-assessment-report-working-group-i/; Working Group II, *AR6 Climate Change 2021: Impacts, Adaptation and Vulnerability*, IPCC Sixth Assessment Report, https://www.ipcc.ch/report/sixth-assessment-report-working-group-ii/. *See also* Exhibit EDH-3 for an analysis of specific possible impacts on Philadelphia.

high-income customers, and thus would pay a higher effective per-unit rate. Finally, increasing fixed charges shifts additional risks onto ratepayers, at a time when many of them are struggling financially due to the global coronavirus pandemic.

IV. Planning for a Climate-Constrained Future

Q. Has Pennsylvania Governor Tom Wolf acknowledged the risk of climate change to the Commonwealth of Pennsylvania, and has he committed to addressing this risk?

A. Yes. In Executive Order Number 2019-01, Governor Wolf stated:

> [C]limate change impacts in Pennsylvania are real and continue to put Pennsylvanians at risk: in recent years, extreme weather and natural disasters have become more frequent and more intense. Like many areas of the United States, Pennsylvania is expected to experience higher temperatures, changes in precipitation, and more frequent extreme weather events and flooding because of climate change in the coming decades…the Commonwealth is committed to further reducing its net greenhouse gas emissions which, left unchecked, would create a high risk of irreversible, widespread, severe climate impacts in the Commonwealth and beyond.[9]

Governor Wolf went on to declare that:

> Pennsylvania's economy, health and safety, and quality of life of its citizens are dependent on the careful stewardship of resources, a healthy economy, and the development of technologies to enable economic growth while protecting the environment.[10]

And finally, that:

> [t]he Commonwealth is committed to joining and working with Pennsylvania businesses and industry to reduce emissions through pollution

[9] Pa. Exec. Order No. 2019-01 at 1 (Jan 8, 2019) ("Order No. 2019-01"), https://www.governor.pa.gov/wp-content/uploads/2019/01/2019-01.pdf.
[10] *Id.* at 2.

> prevention and improved energy efficiency…the Commonwealth is resolved to do its part to address climate change, the most critical environmental threat confronting the world.[11]

Q. Did Governor Wolf establish greenhouse gas emissions reduction targets in Executive Order Number 2019-01?

A. Yes. The Governor stated that "[t]he Commonwealth shall strive to achieve a 26 percent reduction of net greenhouse gas emissions statewide by 2025 from 2005 levels, and an 80 percent reduction of net greenhouse gas emissions by 2050 from 2005 levels."[12]

Q. Has PGW addressed the Governor's Executive Order 2019-01 or the need to adapt its operations and business model to the Governor's greenhouse gas emissions targets in its current filing?

A. No.

Q. Has the Philadelphia City Council taken any action regarding the risks of climate change and the need to reduce greenhouse gas emissions?

A. Yes. On September 26, 2019, the City Council adopted Resolution No. 190728, introduced by Councilmember Quiñones Sánchez, "[u]rging the City of Philadelphia to take measures to achieve fair and equitable transition to the use of 100% Clean Renewable Energy by 2050" and stating that "[t]he City of Philadelphia must continue to take the lead in advancing proactive climate change solutions."[13] Resolution No. 190728

---

[11] *Id.* at 1.
[12] *Id.* at 2.
[13] Urging the City of Philadelphia to take measures to achieve fair and equitable transition to the use of 100% Clean Renewable Energy by 2050. Resolution No. 190728 at 2 (Sept. 26, 2019), https://phila.legistar.com/LegislationDetail.aspx?From=RSS&ID=4142523&GUID=BA06CC3B-7B43-4743-A07E-515A145C4A2A.

also noted that "[t]he City of Philadelphia is obligated to take actions in accordance with Article 1, Section 27 of the Pennsylvania State Constitution, ensuring the people of Pennsylvania "a right to clean air, pure water, and the preservation of the natural, scenic, historic, and esthetic values of the environment."[14]

Q. Did Resolution No. 190728 include specific greenhouse gas emissions reduction and clean energy commitments for the City of Philadelphia?

A. Yes. The Resolution stated that "Mayor James F. Kenney has committed to reducing the City of Philadelphia's carbon footprint by 80% before the year 2050; and has pledged support for the City of Philadelphia to transition its energy to 100% clean renewable energy through the 'Mayors for 100% Clean Energy' in June 2017; and…The City of Philadelphia has committed to "doing its part to meet the obligations of the United States under the Paris Accord to limit global warming to 1.50 C above pre-industrial levels" per resolution number 170706 signed in September 2017."[15]

Finally, Resolution No. 190728 resolves "[t]hat the City of Philadelphia shall take measures to achieve a fair and equitable transition to the use of 100% clean renewable energy for electricity in municipal operations by 2030, for electricity City-wide by 2035, *and for all energy (including heat and transportation) city-wide by 2050 or sooner*."[16]

Q. Has PGW addressed Resolution No. 190728 or the need to conform to the City's emissions reduction and clean energy commitments in its current filing?

A. No.

---

[14] *Id.*
[15] *Id.* at 1.
[16] *Id.* at 3 (emphasis added).

Q. In your opinion, should PGW take the climate goals of the Governor's Executive Order 2019-01 and City Council Resolution No. 190728 into account in its infrastructure planning and in the current rate case?

A. Yes.

Q. Please explain.

A. PGW is asking for a rate increase, in part, to support "initiatives to modernize its infrastructure."[17] For example, the Company proposes to "replace all cast iron main inventory" and claims that its requested rate relief would allow it to do so within 34.6 years.[18] On this schedule, the full replacement program for cast iron mains would be completed by approximately 2055, assuming work commences in 2020. This is five years after 2050, the year by which 1) the City of Philadelphia has committed to transition to 100% clean energy for all purposes city-wide, and 2) Governor Wolf has committed to reduce Pennsylvania's greenhouse gas emissions by 80% to address what he calls "the most critical environmental threat confronting the world."[19]

It is not reasonable or prudent to invest what is likely to ultimately be hundreds of millions of dollars of ratepayer funds in modernizing infrastructure that will have no use by the time the project is complete, and the Commission should not commit to a rate increase at this time to support such a wasteful endeavor. Any ratepayer funds used to replace PGW's distribution infrastructure should be spent in a way that is consistent with the need to reduce and ultimately cease burning fossil fuels, in Philadelphia and

[17] PGW St. No. 1 at 3:13.
[18] *Id.* at 5:11–15.
[19] Order No. 2019-01 at 2.

elsewhere. Doing otherwise risks creating burdensome stranded assets as the Company ultimately is forced to dramatically reduce, and then eliminate, gas sales.

Q. In your opinion, should PGW address its aging gas pipes to reduce leakage from its distribution system at this time?

A. Yes, but in a targeted way. PGW should aggressively address leakage from its pipeline system, starting with the largest leaks, for several reasons—including safety, environmental benefits, and avoiding emissions of a potent greenhouse gas into the atmosphere. The explosion related to a 92-year-old gas main in South Philadelphia on December 19th, which killed two people and destroyed several homes, is ample reminder of the urgency of this need.[20] However, addressing this problem need not and should not mean investing wholesale in new gas delivery infrastructure that the Company would need to amortize over decades of continued gas sales.

V. Need for a Climate Business Plan

Q. If not replace and modernize its gas delivery system as the Company has proposed, what should PGW do instead?

A. As a first step, the Company should develop a CBP that can serve as a roadmap for how it can ensure that its future investments and operations are consistent with needed reductions in greenhouse gas emissions. These reductions should be consistent with the goals established for the Commonwealth of Pennsylvania and the City of Philadelphia as described above. In the absence of such a plan, PGW risks wasting hundreds of millions

[20] Jake Blumgart, *'We're scared,' South Philly residents say after city officials reveal explosion case*, WHYY (Jan. 16, 2020) https://whyy.org/articles/were-scared-south-philly-residents-say-after-city-officials-reveal-explosion-cause/.

of dollars of ratepayer funds on investments that are destined to become stranded assets in Philadelphia's low-carbon future.

Q. What sort of actions should the Commission expect to see in a Climate Business Plan to help the Company meet these emissions targets?

A. The CBP should consider the impacts of climate change and the need to tailor the Company's investments to serve customers in a low-carbon future on PGW's infrastructure needs. The goal of the CBP would be to reduce and ultimately cease selling fossil fuels, and to eliminate GHG emissions from the Company's operations. Elements of such a plan should include:

1. Aggressive energy efficiency programs to help reduce customer gas usage, including building weatherization through insulation and air sealing;
2. Incentives for customers to switch from gas-fueled to electric equipment, including high-efficiency electric heat pumps for heating and cooling and electric ranges;
3. Provision of energy audit services and financing for customers transitioning off of gas appliances and infrastructure;
4. A moratorium on new gas hookups for new construction as of a date certain;
5. Pursuit of non-pipeline alternatives ("NPA") for retiring aging gas infrastructure~~, such as electrification~~; and
6. A new revenue model that monetizes non-gas energy services and mitigates the effect of decreasing volumetric sales without heavy reliance on regressive fixed customer charges.

Q. By what process should the Climate Business Plan be developed and considered?

A. PGW should develop a CBP through a public process. Public participation is essential to ensure the adequacy and public understanding and acceptance of the CBP. PGW should solicit written public comment on a draft CBP and hold at least one public meeting at which the public can comment. Once developed, PGW should submit a proposed CBP to the Commission as evidence in support of proposed changes to existing rates and charges, particularly where those changes relate to infrastructure spending.

Q. Has the Philadelphia City Council initiated any proceedings in support of this type of inquiry into the climate sustainability of PGW's operations and practices?

A. Yes. The City Council and the Company are well aware of the risks that climate change poses to PGW's current business model, and the need to conform its business practices accordingly, even if the Company chooses to ignore them for purposes of its current filing. On December 6, 2018, the City Council adopted Resolution No. 181081, which called for a hearing on the climate sustainability of PGW and found that:

- "Forces outside the control of either PGW or the City of Philadelphia will call upon [PGW's] history of innovation: the increasing destruction caused by global warming and the twin financial threats of more efficient energy usage and competitive price of renewable energy sources";[21]

- "Climate change is not just a future threat to be avoided, but – with the planet having already experienced one degree Celsius warming due to human activity, which has caused the rising sea levels, severe storms, and other extreme weather events we see right now – a present danger requiring significant human adjustments to avoid far worse damage";[22]

- "Falling demand and increasing competition threaten not only PGW's bottom line, or even the City's immediate financial interests, but critically the rates paid by residents who rely on utility services for warmth and cooking, without

[21] Authorizing the Committee on Transportation and Public Utilities to conduct hearings regarding the sustainability of the Philadelphia Gas Works. Resolution No. 181081 at 1 (Dec. 6, 2018), https://phila.legistar.com/View.ashx?M=F&ID=6828110&GUID=C0AC9F32-F7E1-41B3-AF8E-CB25B86D6837.
[22] *Id*.

adequate resources to use the latest insulation in their homes, install solar panels on their roofs, purchase efficient appliances, procure top-of-the-line windows, or otherwise adapt their homes";[23] and

- "To ensure the reliability of utility heating and cooking service for another 180 years and more, the City must explore how to adapt PGW to the needs of the changing market and planet[.]"[24]

On April 26, 2019, the City Council held a hearing on PGW's sustainability, as called for by Resolution No. 181081.[25] At this hearing, numerous members of the public provided testimony on ideas for the future of PGW in a climate-constrained world, including the need for a "just transition away from fossil fuels."[26] At this hearing, Christine Knapp, Director of Sustainability for the City of Philadelphia, stated that the City was working with PGW to develop a "business diversification study which would provide a roadmap toward an environmentally and economically sustainable future for PGW that can be a model for other gas utilities around the country."[27] Barry O'Sullivan, Director of Corporate Communications at PGW, stated that the Company is an "energetic supporter[] of the emissions reduction goals that Philadelphia has adopted. And we are engaged with the Philadelphia Energy Authority and the Office of Sustainability and others so we can help achieve them."[28] Mr. O'Sullivan assured the City Council that the Company's "scientists and engineers and regulatory specialists had studied issues of environmental impact, sustainability and emission reduction for many years"[29] and that "despite some

[23] *Id*. at 2.
[24] *Id*.
[25] *See* Transcript of Committee on Transportation and Public Utilities, Council for the City of Philadelphia (Apr. 26, 2019) ("Committee Meeting Transcript"), https://council-transcript-room.s3.amazonaws.com/Public%20Hearings/transpor/2019/tr042619.pdf.
[26] *Id*. at 7.
[27] *Id*. at 97–98.
[28] *Id.* at 101.
[29] *Id*. at 102.

claims to the contrary, PGW's absolutely committed to improving the environment we all share and which our children would inherit. We breathe the same air you breathe."[30]

A notice of a Request for Proposals ("RFP") for consulting services for this study from the City of Philadelphia dated October 22, 2019 noted that PGW "has been experiencing a decrease in customers and usage for decades due to appliance efficiencies and conservation efforts, and warming weather patterns have also contributed to demand reductions"—issues that "will only intensify as temperatures are projected to continue to rise in the future and new policies may restrict the production of greenhouse gases." [31] Specifically, the City sought "a business diversification study that provides a range of economically, and environmentally sustainable pathways for the utility to consider pursuing. Along with anticipated carbon emissions reductions, the study should also present the financial, regulatory and technological viability of each pathway."[32]

The City's Office of Sustainability's revised Fiscal Year 2021 Budget Testimony stated that its plans for Fiscal Year 2021 include "completing a PGW business diversification study to understand how the utility can thrive in a carbon-constrained future[.]"[33] Materials and findings developed for this study might provide a baseline or foundation for developing a CBP of the type described herein.

---

[30] *Id.* at 106.

[31] Public Bids, *City of Philadelphia's RFP for a Philadelphia Gas Works Business Diversification Study*, Philadelphia Energy Authority (Oct. 22, 2019), https://philaenergy.org/public_bids/city-of-philadelphias-rfp-for-a-philadelphia-gas-works-business-diversification-study/.

[32] *Id*.

[33] Office of Sustainability, *Revised Fiscal Year 2021 Budget Testimony*, City of Philadelphia at 2 (June 2020), http://phlcouncil.com/wp-content/uploads/2020/06/FY21-Budget-Hearings-Testimony_OOS_FINAL.pdf. The testimony also stated this timeline may be delayed by the COVID-19 pandemic.

Given City Council Resolution No. 181081, the public hearing held in April 2019 that included comments from a PGW representative, and the issuance of an RFP for the diversification study, PGW certainly cannot claim to be unaware of the need to reform its business practices, or that it has not already begun to look into the challenges it faces in preparing for the climate-constrained future. This awareness cannot be reconciled with PGW's $70 million rate increase filing, which states that among its purposes is to support "initiatives to modernize its infrastructure,"[34] and which is predicated on continuing to make fossil fuel-oriented infrastructure investments over the next four decades.

Q. Does the initiative to develop a business diversification study negate the need for a CBP?

A. No. The diversification study is important but it will not displace the need for a CBP to identify and analyze specific actions, such as those described in my testimony above, that will guide and constrain the Company's infrastructure investments and allow it to ultimately eliminate carbon emissions. This is why PGW must be ordered to prepare an adequate CBP, and why approval for its rate increase must be conditioned on consistency of its proposed investments with the CBP.

Q. Are you aware of other jurisdictions that have undertaken public processes to help gas utilities conform to the need to reduce carbon emissions?

A. Yes. The Massachusetts Attorney General requested that the State's Department of Public Utilities "open an investigation…to examine the issues facing gas distribution companies

[34] PGW St. No. 1 at 3:13.

as the Commonwealth rapidly moves to achieve its 2050 GHG emission reduction mandate."[35] The Attorney General further requested that this investigation "provides the Department with the opportunity to solicit utility and stakeholder input and develop a nation-leading regulatory and policy roadmap to guide the evolution of the gas distribution industry companies, provide ratepayer protection, and allow the Commonwealth to move into its net-zero GHG emissions energy future."[36]

The Attorney General concluded:

> [t]he Department should take proactive steps to investigate the future role of the [gas utilities] as the Commonwealth transitions to a clean, increasingly electrified, and decarbonized heating sector. An investigation will provide the platform for the Department to assess fully the prevailing concerns and relevant issues facing [gas utilities] and enable it to develop policies and a regulatory framework to ensure an orderly and fair transition to a clean energy heating sector, to ensure continued safe and reliable gas service even as demand declines, and to ensure that consumers do not pay unnecessary costs.[37]

Q. You identified pursuit of non-pipeline alternatives as one important element of a CBP. Can you provide an example of such a program?

A. Yes. The Central Hudson Gas and Electric Corporation in New York created an NPA program pursuant to a settlement agreement in its 2017 rate case.[38] As described in the order accepting the settlement:

> The Company is being encouraged…to pursue non-pipes alternatives to meet demand for heating fuels. One way is through the incentives focused on geothermal heating and cooling…but the Company has also committed to pursue additional natural gas efficiency, demand response programs, and

---

[35] Exhibit EDH-4 at 18
[36] *Id.* at 3.
[37] *Id.* at 17.
[38] Exhibit EDH-5 at 69.

> will issue an RFP focused on non-pipes alternatives that can displace traditional infrastructure projects. When combined with the reductions in methane leakage, the programs that seek to replace natural gas usage with other means of providing space heating or reducing fuel consumption will help ensure the transition to lower carbon energy markets in New York State.[39]

Q. Is the Central Hudson NPA cost-effective?

A. Yes. According to the most recent (December 2019) Non-Pipeline Alternative Annual Report,[40] benefits of Central Hudson's NPA program outweigh costs by a ratio of 3.3 to 1 as measured by the Societal Cost Test ("SCT").[41]

VI. Fixed vs. Volumetric Charges

Q. Turning to the question of PGW's proposed rate structure, please explain the difference between fixed and volumetric charges.

A. Each customer's monthly bill is composed of two types of charges – fixed and volumetric. The fixed charge is assessed each month to each metered customer, regardless of the customer's usage for that monthly billing period. The volumetric charge is a "$/Mcf"[42] charge and is directly dependent on the customer's gas usage during the billing period.

Q. How has the Company proposed to modify its fixed rates in this matter?

A. The Company has proposed to increase its fixed "per-customer" charge such that a larger proportion of its costs will be covered by fixed charges, and a lower portion by

---

[39] *Id.* at 68–69.
[40] Exhibit EDH-6.
[41] *Id.* at 5.
[42] Mcf = thousand cubic feet of gas, equal to a heating value of approximately one million British Thermal Units (BTU) or 10 therms. According to the Company's filing, a typical residential heating customer uses approximately 75 Mcf of gas per year, primarily in the heating season. PGW St. No. 1 at 8:3–5.

volumetric charges. For example, under the Company's proposal a residential customer ("Rate GS") customer would pay a fixed charge of $19.25 per month regardless of usage. The current fixed charge for residential customers is $13.75 per month, [43] so this would be an increase of 40%.

Q. How does PGW's proposed fixed rate compare to that of other gas utilities in Pennsylvania?

A. According to the comparison provided by PGW witness Gregory Stunder, PGW's fixed customer charge for residential customers would be by far the highest of any gas utility in Pennsylvania identified by the Company.[44] PGW's customer charge would be 15% higher than that of Columbia Gas, the next highest identified, and 35% higher than the average.

Q. What is the rationale for a rate structure including both fixed and variable components?

A. The usual rationale is the seemingly straightforward idea that the fixed charges are related to the fixed costs borne by the utility – the distribution system, pumping stations, and administrative costs that serve all customers – while the volumetric charge is related to variable costs, primarily the cost of gas. The idea that fixed costs can be recovered through fixed charges and variable costs through variable charges is sometimes referred to as "straight fixed/variable" rate design, or "SFV". This seems to be one of the bases of the Company's request in this case, along with providing additional "revenue stability."[45]

[43] PGW St. No. 1 at 7:3–5.
[44] *Id.* at 7.
[45] *See* PGW St. No. 6.

Q. You say this is "seemingly" straightforward. Please explain.

A. So-called "fixed costs" are only fixed in the short term, i.e., month-to-month. In the longer term, they are dependent on the level of sales just as fuel and other variable costs are. For example, it is the overall level of gas sales that drives the need for investment in the distribution system over time, and even the requirements for administrative services at the utility. Any measures that help customers reduce gas usage also ultimately help the utility save money on these so-called "fixed" costs. This issue was explored in depth in a recent report[46] by the Regulatory Assistance Project ("RAP"), a regulatory think-tank staffed by "former utility and environmental regulators, industry executives, system operators, and other policymakers and officials with extensive experience in the power sector."[47] I have provided this report as Exhibit EDH-2. As noted therein:

> Utilities often argue that the majority of their costs are fixed, and extrapolate from this that these fixed costs should be recovered in fixed charges. This is lacking in both economic foundation and accounting principles: Just because a cost is fixed in the short run does not mean it should be recovered in a fixed charge. Utilities often assert that most of their costs are "fixed" and should be recovered in fixed charges. While interest and depreciation expense are fixed in the short run, virtually every other cost is variable even in the short run. Even if a cost is "fixed" it does not mean it should be recovered in a fixed charge. Investments in power plants are made to provide a supply of electricity, and the costs should be recovered in proportion to how much of that production a customer uses…Transmission facilities are built to connect remote power plants to the communities needing power, and are essentially an alternative to building those power plants directly in the community. [48]

[46] Exhibit EDH-2. It should be noted that the discussion in Exhibit EDH-2 is primarily focused on electric utilities, but is equally applicable to gas utilities.

[47] Regulatory Assistance Project, *About*, https://www.raponline.org/about/ (last visited June 12, 2020).

[48] Exhibit EDH-2 at D-5.

Q. What set of costs is the company proposing to recover through its monthly fixed customer charge?

A. A complete breakdown is provided in PGW's Cost of Service Allocation Study, developed by consulting firm Gannet Flaming and presented as Exhibit CEH-1 to the direct testimony of PGW witness Constance E. Heppenstall, Schedule E. Without going into detail here, the list includes components of numerous expenses categorized as "Distribution Expenses", "Customer Accounting Expenses", "Customer Service and Information Expenses", "Administrative and General Expenses", "Distribution Plant", "General Plant", "Interest and Other Expenses", and "City Payment."

Q. What is wrong with recovering these costs through fixed customer charges?

A. It is both unfair and detrimental to ratepayers, and particularly to lower-income ratepayers. This is because a fixed charge effectively charges lower-usage customers, who tend to be lower-income, more than higher-usage customers on a per-unit basis. As described in the RAP report:[49]

> The vast majority of low-income households use below-average amounts of electricity, and will pay higher bills with an SFV rate design…[m]ulti-family housing residents also have below-average usage and are adversely impacted by high fixed charge rate designs. These residents typically have below-average dwelling size, below-average residents per household, and below-average usage. They are also quite obviously cheaper to provide electric distribution service to — since they are close together and many customers are served by a single distribution transformer.

This disproportionate impact on low-income customers should be of particular concern to the Commission at the current time, when these same households are suffering

[49] Exhibit EDH-2 at D-2–D-3.

disproportionately from the effects of the coronavirus pandemic, and many are in greater need than ever of opportunities to lower their monthly expenses.

Q. Has PGW analyzed the impact that its proposed increase in fixed customer charge would have on low-income customers?

A. No. The Clean Air Council requested this information in its Discovery Request CAC-01-CAC-01-6,[50] and the Company responded that it had conducted no such analyses. This is concerning due to the proportion of low-income ratepayers PGW serves. As Barry O'Sullivan, Director of Corporate Communications for PGW acknowledged at a City Council hearing on April 26, 2019, "More than half of [PGW ratepayers] either live below or are within stumbling distance of the federal poverty level."[51]

Q. Can you provide an example of how other jurisdictions have responded to utility requests to move toward higher fixed customer costs?

A. Yes. In a 2015 case involving the utility People's Gas, the Illinois Commerce Commission rejected the applicant's proposal to move closer to an SFV rate design on these and other grounds:

> The Commission finds that SFV based rates that assume that non-storage demand related distribution costs should be allocated on a per customer basis are inconsistent with the public policies of attributing costs to cost causers, encouraging energy efficiency and eliminating inequitable cross-subsidization of high users by low users of natural gas.[52]

As intervener Citizens Utility Board pointed out in the same case:

> By failing to send proper price signals, the Companies' proposed rate design

[50] Exhibit EDH-7.
[51] Committee Meeting Transcript at 101.
[52] Exhibit EDH-8 at 176.

> denies consumers who conserve the benefit of their actions, and punishes customers who are frugal. The proposed SFV charges are indifferent to efficiencies in usage and demand. In contrast, the Commission has recognized that lower monthly customer charges and higher volumetric charges can advance energy use conservation and efficiency policy objectives by providing a greater price signal.[53]

As noted in the quotes above, higher fixed customer charges cause cross-subsidization of higher-income customers by lower-income customers, and are incompatible with programs to promote energy efficiency.

Q. Has PGW analyzed the impact that its proposed increase in fixed customer charge would have on energy efficiency initiatives such as the Company's EnergySense program?

A. No. The Clean Air Council requested this information in its Discovery Request CAC-01-CAC-01-5,[54] and the Company responded that it had conducted no such analyses.

Q. Are there other reasons that moving closer to an SFV rate design is detrimental to customers?

A. Yes. Increasing the fixed customer charge portion of utility bills transfers risk from the Company to its customers. This is the "benefit" the Company refers to as "provid[ing] more revenue stability."[55] If sales of gas decrease due to abnormal weather, adverse economic conditions, customer energy efficiency, or any other reason, the Company will still collect the full per-customer charge even as it loses revenues from gas sales (and saves money on avoided wholesale gas purchases). In this sense it is an expression of the monopoly power of the utility, and should be regarded with skepticism by the regulatory

---

[53] *Id.* at 169.
[54] Exhibit EDH-7.
[55] PGW St. No. 6 at 7:5.

body whose responsibility it is to rein in that monopoly power. Turning again to the RAP report:

> Another important role of utility regulation is to impart to natural monopolies (as electric distribution utilities are generally categorized) the same pricing discipline that competitive firms experience, so that they endeavor to minimize costs and maximize customer satisfaction. If utilities are allowed to recover their system costs in fixed charges for the privilege of being a customer, much of this discipline is lost. Conversely, if they recover their costs in the per kWh price, they must compete with alternatives to electricity consumption from the utility, including energy efficiency and customer self-generation. This discipline helps to hold costs down for all consumers.[56]

Most non-monopoly companies cannot charge customers simply for the privilege of being a customer – they have to entice customers to pay based on the desirability of their product relative to alternatives. In the case of PGW's gas monopoly, the alternatives include such individually and socially beneficial alternatives as improved weatherization and other energy efficiency measures, and conversion to high-efficiency electric heat pumps.

Finally, it should be noted that conversion to rate design with higher fixed customer components actually causes *higher* energy use, exactly the opposite of what is needed to promote customer welfare, to promote energy efficiency, and to meet the Commonwealth's and the city's climate goals. Turning once again to the RAP report for an example:

> When Madison Gas & Electric originally proposed a $69/month customer charge, it also proposed reducing the per kWh rate from $.14/kWh in winter and $.15/kWh in summer to about $.04/kWh. Using the economic principle of elasticity (higher prices result in a lower quantity demanded), and applying a moderate elasticity factor of -0.2 (a 1% increase in price results

[56] Exhibit EDH-2 at D-4–D-5.

> in a 0.2% reduction in usage), The Regulatory Assistance Project estimated that the proposed rate design could result in about a 14.5% increase in usage over time. The expectation is that consumers would raise thermostats, defer efficiency investments, and be less attentive to simple things like turning off unused lights.[57]

Q. Don't some competitive companies, such as cable television providers and cellular phone services, rely on fixed monthly charges for their services?

A. Yes. However, in these examples (as in the example of the very popular Amazon Prime service) the companies specifically benefit from *increased* customer usage – in other words, their profits increase as they deliver more content, data, or consumer goods through their distribution systems. Such companies eschew a traditional volumetric "rate structure" that would provide an incentive for their customers to reduce usage. This should not be the case with a gas utility such as PGW, which as a regulated utility should be primarily concerned with meeting customer needs at the lowest possible cost, which includes helping them conserve energy and reduce costs.

Q. In your opinion, what is an appropriate per-customer fixed charge?

A. I agree with the principle articulated in the RAP report that "[a] customer should be able to connect to the grid for no more than the cost of connecting to the grid."[58] This includes the amortized cost of the meter, the cost of billing, and any other cost specifically related to hooking up the individual customer. It does not include distribution or any other system costs.

---

[57] *Id.* at D-3 (reference omitted).
[58] Exhibit EDH-2 at D-4.

VII. Risks for PGW Customers

Q. What are the risks associated with the Company's proposal?

A. The primary risk is that the Company will continue to spend ratepayer funds on replacing, upgrading, and modernizing infrastructure that has no value in a climate-constrained future, and no place in a state or a city that has set aggressive greenhouse gas emission goals, and will eventually become stranded investments. PGW may believe that it can continue to sell natural gas in perpetuity, and if the Commission allows it to move toward increased fixed rates to its customers' detriment, it will continue to sell gas at its current volume or greater for the short term.

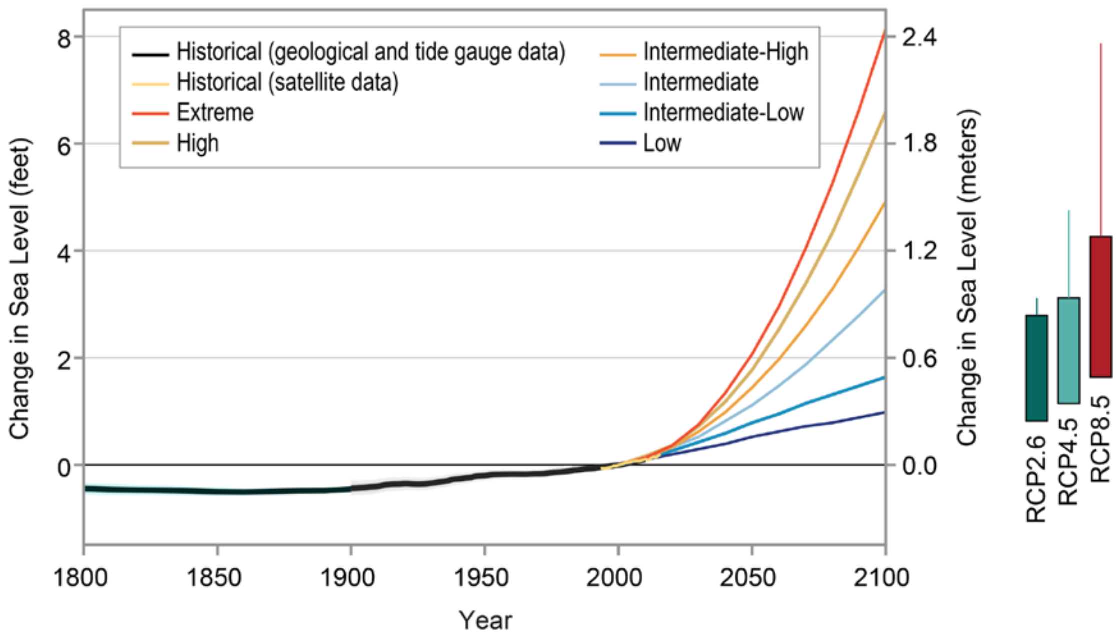
Over the long term, of course, this vision is a fantasy. Climate science tells us that we cannot continue to burn fossil fuels at the rate we have been over the next several decades without catastrophic and irreparable harm to the climate of the planet, as well as to the economy and livability of Philadelphia. A recent exhaustive report on the risk of sea level rise to Pennsylvania (Exhibit EDH-3) looked at what plausible levels of sea-level rise by the later 21st century would mean for the Commonwealth:

> Nearly 9 square miles of land lie less than 4 feet above the high tide line in Pennsylvania. Some $686 million in property value, and more than 5,000 people residing in more than 2,000 homes – mostly in Philadelphia – sit on this area. More than $250 million of the property sits within just one zip code, 19153 (Philadelphia International Airport). Totals jump to some $3.4 billion, more than 27,000 people, and more than 12,000 homes on more than 29 square miles of land under 9 feet.
>
> The state has 63 miles of road below 4 feet, plus 23 hazardous waste sites, 15 wastewater sites, and 4 power plants. At 9 feet, these numbers grow to nearly 227 miles of road, 114 hazardous waste sites, 37 wastewater sites, and 10 power plants, as well as 2 museums. Surging Seas Risk Finder presents results for many more infrastructure and facility categories, as well as population groups and potential contamination sources.

> The Philadelphia International Airport appears to be protected at water levels up to 4 feet above the local high tide line, but not at higher levels.[59]

A recent projection of possible global sea level increases due to global warming is presented in Figure 1. According to this projection, four feet of sea level rise is approached by the end of the century under the "intermediate" scenario, and exceeded in the "intermediate-high" or higher scenarios.[60]

Figure 1. Projected global sea-level rise. U.S. Global Change Research Program, *Fourth National Climate Assessment, Chapter 2: Our Changing Climate, Figure 2.3*



If emissions are not curtailed, large areas of Philadelphia will be regularly inundated either persistently or during storm surges, making currently valuable residential and business areas uninhabitable. Thus there are two possible futures: either Philadelphia and the nation take aggressive action to address global climate change, in which case PGW's

[59] Exhibit EDH-3 at 16.

[60] In my opinion, the levels shown in Figure 1 may be conservative because they do not include the risk of sudden, catastrophic events such as the collapse of large portions of the Antarctic ice sheets. As the referenced report acknowledges, "a rise exceeding 8 feet (2.4 m) by 2100 is physically possible, although the probability of such an extreme outcome cannot currently be assessed."

investments will be stranded as gas consumption dwindles, or uncontrolled climate change renders much of the city uninhabitable, destroying energy and other infrastructure, and similarly renders PGW's investments a stranded waste of ratepayer funds.

This is why I recommend that PGW be directed to produce a CBP for reducing and ultimately eliminating its sales of natural gas. Its infrastructure investments, along with current and all future rate requests, should then be designed to conform to this plan.

VIII. Recommendations and Conclusion

Q. What are your recommendations for this Commission?

A. I make the following recommendations:

1. I recommend that the Commission find that the Company has inadequately studied potential cost-effective alternatives to its proposed infrastructure work (such as energy efficiency ~~and electrification~~) and has inadequately considered climate trends in its infrastructure planning, creating a likelihood of future stranded assets. As a result, I recommend that the Commission find that the Company has failed to demonstrate that its proposed investments are necessary, reasonable, or prudent. To redress these deficiencies, and to provide the Commission with the necessary information to determine whether or not the Company's proposed rate increase is just and reasonable, the Commission should direct the Company to produce a Climate Business Plan ("CBP"). The CBP, which should include consideration of potentially cost-effective alternatives to maintaining or expanding the Company's gas infrastructure, such as energy efficiency ~~and electrification~~, should serve as a

roadmap for infrastructure planning that is consistent with climate trends and consistent with the goals set forth by Governor Wolf and the Philadelphia City Council to aggressively reduce and ultimately eliminate greenhouse gas emissions in the Commonwealth of Pennsylvania and the City of Philadelphia.

2. I recommend that the Commission deny PGW's requested rate increase pending completion of its CBP and a finding by the Commission that (a) the CBP is consistent with the demonstrated need to reduce greenhouse gas emissions, and (b) that PGW's request is consistent with the actions set forth in the CBP. If necessary, the Commission could approve a narrowly tailored exception for safety-related distribution system maintenance and addressing major gas leakage, but even in these cases the Company should be directed to first investigate the potential for non-pipeline alternatives.

3. Whether or not the Commission approves PGW's overall requested rate increase, I recommend that the Commission reject PGW's proposal to increase its fixed customer charge, which would be harmful to low-income customers and at cross-purposes with energy efficiency initiatives. The Company should be directed to build any approved rate increase into the volumetric charge for all customer classes.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
: Docket No. R-2020-3017206
v. :
:
Philadelphia Gas Works :
:
:
:

VERIFICATION

I, Ezra D. Hausman, Ph.D., hereby verify that the facts set forth in my testimony are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Dated: June 15, 2020

/s/ ____________________________

Ezra D. Hausman, Ph.D.
Ezra Hausman Consulting
77 Kaposia Street
Auburndale, Massachusetts 02466
(617) 875-6698
ezra@ezrahausman.com

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of this electronically-filed document upon the parties, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a party).

Carrie B. Wright, Esq. Bureau of Investigation & Enforcement Pennsylvania Public Utility Commission Commonwealth Keystone Building 400 North Street P.O. Box 3265 Harrisburg, PA 17105-3265 carwright@pa.gov	Gregory J. Stunder, Esq. Philadelphia Gas Works 800 West Montgomery Avenue Philadelphia, PA 19122 Gregory.Stunder@pgworks.com
Daniel G. Asmus, Esq. Sharon E. Webb, Esq. Office of Small Business Advocate Forum Place, 1st Floor 555 Walnut Street Harrisburg, PA 17101 dasmus@pa.gov swebb@pa.gov	John W. Sweet, Esq. Elizabeth R. Marx, Esq. Ria M. Pereira, Esq. Pennsylvania Utility Law Project 118 Locust Street Harrisburg, PA 17101 pulp@palegalaid.net
Robert D. Knecht Industrial Economics Incorporated 2067 Massachusetts Ave. Cambridge, MA 02140 rdk@indecon.com	Todd S. Stewart, Esq. Hawke McKeon & Sniscak LLP 100 North Tenth Street Harrisburg, PA 17101 tsstewart@hmslegal.com
Darryl A. Lawrence, Esq. Christy M. Appleby, Esq. Santo G. Spataro, Esq. Laura Antinucci, Esq. Office of Consumer Advocate 5th Floor, Forum Place 555 Walnut Street Harrisburg, PA 17101-1923 OCAPGW2020@paoca.org	Charis Mincavage, Esq. Adeolu A. Bakare, Esq. Jo-Anne Thompson, Esq. McNees Wallace & Nurick LLC 100 Pine Street P.O. Box 1166 cmincavage@mcneeslaw.com abakare@mcneeslaw.com jthompson@mcneeslaw.com
Josie B.H. Pickens, Esq. Joline Price, Esq. Robert W. Ballenger, Esq. Kintéshia Scott, Esq. Community Legal Services	

1424 Chestnut Street Philadelphia, PA 19102 jpickens@clsphila.org jprice@clsphila.org rballenger@clsphila.org kscott@clsphila.org	Lauren M. Burge, Esq. Eckert Seamans Cherin & Mellott, LLC 600 Grant Street, 44th Floor Pittsburgh, PA 15219 412-56602146 lburge@eckertseamans.com
Daniel Clearfield, Esq. Sarah C Stoner, Esq. Kristine Marsilio, Esq. Eckert Seamans Cherin & Mellott, LLC 213 Market Street 8th Floor Harrisburg, PA 17101 dclearfield@eckertseamans.com sstoner@eckertseamans.com kmarsilio@eckertseamans.com	

Dated: June 15, 2020

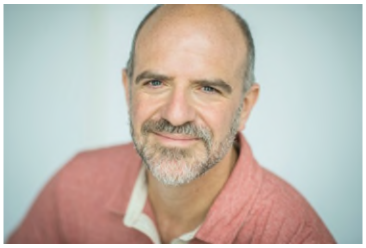
/s/

Devin McDougall
Staff Attorney
Earthjustice
1617 John F. Kennedy Blvd., Suite 1130
Philadelphia, PA 19103
dmcdougall@earthjustice.org

Exhibit EDH-1
Resume of Ezra D. Hausman, Ph.D.

Ezra D. Hausman, Ph.D.

Curriculum Vitae



I am an independent consultant in energy and environmental economics.

I have worked for over two decades as an energy market expert with a focus on market design and market restructuring, planning and ratemaking, energy efficiency programs, environmental regulation, and pricing of energy, capacity, transmission, losses and other electricity-related services. I have performed market analysis, provided expert testimony, led workshops and working groups, and provided other support in both regulated and restructured electricity markets for clients including federal and state agencies, offices of consumer advocate, legislative bodies, cities and towns, non-governmental organizations, foundations, industry associations, and resource developers.

I hold a Ph.D. in atmospheric science from Harvard University, an S.M. in applied physics from Harvard University, an M.S. in water resource engineering from Tufts University, and a B.A. in psychology from Wesleyan University.

PROFESSIONAL EXPERIENCE

Ezra Hausman Consulting, Newton, MA. President, March 2014 – Present.
I provide research, analysis, expert testimony, and policy support services in regulatory, litigation, and stakeholder processes covering a wide range of electric sector and electriciuty market issues. The focus of my consulting work includes:

- Ratemaking and regulatory proceedings
- Wholesale market design and analysis for electricity, generating capacity, and related services
- Demand-side management program design and cost/benefit analysis
- Interaction of air quality and environmental regulations with electricity markets
- Analysis and implementation of the Clean Power Plan and other greenhouse gas rules
- Clean Air Act enforcement support
- Long-term electric power system planning
- Energy efficiency and renewable energy programs and policies
- Consumer and environmental protection
- Market power and market concentration analysis in electricity markets.

Synapse Energy Economics Inc., Cambridge, MA.
Chief Operating Officer, March 2011 – February 2014;

Vice President, July 2009 – February 2014;
Senior Associate, 2005-2009.

- Conducted research, wrote reports, and presented expert testimony pertaining to consumer, environmental, and public policy implications of electricity industry regulation. Provided expert support and representation in planning, greenhouse gas mitigation, and other stakeholder processes.
- As Vice President and Chief Operating Officer, I was also responsible for day-to-day operations of the company, quality assurance, client service, and professional development of staff.

Charles River Associates (CRA), Cambridge, MA. Senior Associate, 2004-2005
CRA acquired Tabors Caramanis & Associates in October, 2004.

Tabors Caramanis & Associates, Cambridge, MA. Senior Associate, 1998-2004
As a member of the modeling group, developed and maintained dispatch modeling capability in support of electricity market consulting practice.

Performed modeling and analysis of electricity markets, generation and transmission systems. Projects included:

- Several market transition cost-benefit studies for development of Locational Marginal Price (LMP) based markets in US electricity markets
- Long-term market forecasting studies for valuation of generation and transmission assets,
- Valuation of financial instruments relating to transmission system congestion and losses
- Modeling and analysis of hydrologically and electrically interconnected hydropower system operations
- Natural gas market analysis and price forecasting studies
- Co-developed an innovative approach to hedging financial risk associated with transmission system losses of electricity
- Designed, developed and ran training seminars using a computer-based electricity market simulation game, to help familiarize market participants and students in the operation of LMP-based electricity markets.
- Developed and implemented analytical tools for assessment of market concentration in interconnected electricity markets, based on the "delivered price test" for assessing market accessibility in such a network
- Performed regional market power and market power mitigation studies
- Performed transmission feasibility studies for proposed new generation and transmission projects in various locations in the US
- Provided analytical support for expert testimony in a variety of regulatory and litigation proceedings, including breach of contract, bankruptcy, and antitrust cases, among others.

Global Risk Prediction Network, Inc., Greenland, NH. Vice President, 1997-1998
Developed private sector applications of climate forecast science in partnership with researchers at Columbia University. Specific projects included a statistical assessment of grain yield predictability in several crop regions around the world based on global climate indicators (Principal Investigator); a statistical assessment of road salt demand predictability in the United States based on global climate indicators (Principal Investigator); a preliminary design of a climate and climate forecast information website tailored to the interests of the business community; and the development of client base.

Hub Data, Inc., Cambridge, MA. Financial Software Consultant, 1986-1987, 1993-1997
Responsible for design, implementation and support of analytic and communications modules for bond portfolio management software; and developed software tools such as dynamic data compression technique to facilitate product delivery, Windows interface for securities data products.

Abt Associates, Inc., Cambridge, MA. Environmental Policy Analyst, 1990-1991
Quantitative risk analysis to support federal environmental policy-making. Specific areas of research included risk assessment for federal regulations concerning sewage sludge disposal and pesticide use; statistical alternatives to Most-Exposed-Individual risk assessment paradigm; and research on non-point sources of water pollution.

Massachusetts Water Resources Authority, Charlestown, MA. Analyst, 1988-1990
Applied and evaluated demand forecasting techniques for the Eastern Massachusetts service area. Assessed applicability of various techniques to the system and to regional planning needs; and assessed yield/reliability relationship for the eastern Massachusetts water supply system, based on Monte-Carlo analysis of historical hydrology.

Somerville High School, Somerville, MA. Math Teacher, 1986-1987
Courses included trigonometry, computer programming, and basic math.

EDUCATION

Ph.D., Earth and Planetary Sciences. Harvard University, Cambridge, MA, 1997

S.M., Applied Physics. Harvard University, Cambridge, MA, 1993

M.S., Civil Engineering. Tufts University, Medford, MA, 1990

B.A., Wesleyan University, Psychology. Middletown, CT, 1985

FELLOWSHIPS, AWARDS AND AFFILIATIONS

UCAR Visiting Scientist Postdoctoral Fellowship, 1997

Postdoctoral Research Fellowship, Harvard University, 1997

Certificate of Distinction in Teaching, Harvard University, 1997

Graduate Research Fellowship, Harvard University, 1991-1997

Invited Participant, UCAR Global Change Institute, 1993

House Tutor, Leverett House, Harvard University, 1991-1993

Graduate Research Fellowship, Massachusetts Water Resources Authority, 1989-1990

Teaching Fellowships:

> **Harvard University:** *Principles of Measurement and Modeling in Atmospheric Chemistry; Hydrology; Introduction to Environmental Science and Public Policy; The Atmosphere.*
>
> **Wesleyan University:** *Introduction to Computer Programming; Psychological Statistics; Playwriting and Production.*

Community Service

> *Vice President of Finance,* Congregation Dorshei Tzedek, 2018 - Ongoing
> *Academic Mentor and Athletic Coach,* SquashBusters Boston, 2014 - Ongoing
> *Judge,* Cleantech Open innovation competitions, 2015-2016
> *President*, Burr Elementary School Parent Teacher Organization, 2005-2007

EXPERT TESTIMONY AND SERVICES

Public Service Commission of the District of Columbia – 2020
Review and analysis of AltaGas d/b/a/ Washington Gas' "Climate Business Plan" and "Renewable Natural Gas" studies on behalf of Sierra Club.

New Jersey Division of Rate Counsel – 2016-Ongoing
General policy and stakeholder support on matters related to energy efficiency, renewable energy, and electrification of transportation in New Jersey.

New Jersey Board of Public Utilities – 2020-Ongoing
Expert participation is stakeholder process regarding conversion to high-efficiency street lights on behalf of Rate Counsel.

New Jersey Board of Public Utilities – 2019-Ongoing
Expert participation is stakeholder process regarding transportation electrification policies on behalf of Rate Counsel.

Washington Utilities and Transportation Commission – 2020-Ongoing
Expert witness on behalf of the Sierra Club regarding potential sale of ownership sale in Colstrip generating unit.

Utah Public Service Commission (Docket No. 18-035-36) – 2020-Ongoing
Expert witness on behalf of the Sierra Club in Rocky Mountain Power depreciation case.

PacifiCorp Multi-State Protocols Stakeholder Process – 2019-Ongoing
Participation on behalf of Sierra Club in stakeholder process to establish protocols for allocation of resource costs ad benefits among PacifiCorp states.

Advisory Consulting for Natural Resources Defense Council – 2019-2020
Provide advisory and technical support to analysis team.

Memphis Light, Gas and Water – Power Supply Alternatives Study (2019-Ongoing)
Expert support for Sierra Club participation in Power Supply Advisory Team.

Washington Utilities and Transportation Commission (Dockets UE-190334 and UG-190335) – 2019
Expert witness on behalf of the Sierra Club in Avista Energy rate case.

New Jersey Board of Public Utilities – 2014-Ongoing
Expert witness on behalf of the New Jersey Division of Rate Counsel, reviewing and providing testimony on cost effectiveness and program design of various New Jersey gas and electric utility energy efficiency programs.

Public Service Commission of South Carolina (Docket No. 2018-319-E) – 2019
Expert witness on behalf of the Sierra Club in Duke Energy Carolinas rate case.

Public Service Commission of South Carolina (Docket No. 2018-318-E) – 2019
Expert witness on behalf of the Sierra Club in Duke Energy Progress rate case.

Virginia State Corporation Commission (Case No. PUR-2018-00065) – 2018
Expert witness on behalf of the Sierra Club in Dominion Power IRP proceeding.

Missouri Public Service Commission (Case No. EO-2018-0038) – 2018
Expert services in support of Sierra Club's participation in integrated resource planning process.

Florida Public Service Commission (Docket No. 20170225-EI) – 2017-2018
Expert witness on behalf of the Sierra Club in FPL Determination of Need proceeding.

North Carolina Utilities Commission (Docket No. E-7, SUB 1146) – 2017-2018
Expert witness on behalf of the Sierra Club in Duke Energy Carolinas rate case.

North Carolina Utilities Commission (Docket No. E-2, SUB 1142) – 2017
Expert witness on behalf of the Sierra Club in Duke Energy Progress rate case.

Idaho Public Utilities Commission (Case No. AVU-E-17-01) – 2017
Expert witness on behalf of the Sierra Club in Avista Corporation rate case.

Iowa Utilities Board (Docket No. RPU-2017-0002) –- 2017
Expert witness on behalf of the Sierra Club for Interstate Power and Light petition for ratemaking principles for proposed 500 MW wind project.

Washington Utilities and Transportation Commission (Dockets UE-170033 and UG-170034) – 2017
Expert witness on behalf of the Sierra Club in Puget Sound Energy (PSE) rate case.

Clean Power Plan Modeling in PJM and MISO – 2016-2017
Participation on behalf of the Sustainable FERC Project in ISO initiative to model scenarios for state compliance with federal greenhouse gas mitigation rules.

California ISO/PacifiCorp Market Integration – 2015-2017
Technical support to Sierra Club in stakeholder review and participation in all relevant proceedings in California.

United States Department of Justice – US District Court Dallas, TX Division (U.S. vs. Luminant Generation Company, LLC, and Big Brown Power Company, LLC) – Ongoing
Expert witness on behalf of the United States Department of Justice on clean air act enforcement case.

United States Department of Justice – US District Court for the Eastern District of Missouri (Civil Action No. 4:11-CV-00077) – 2013-Ongoing
Expert witness on behalf of the United States Department of Justice on successful prosecution of clean air act case.

Missouri Public Service Commission (Case No. EO-2015-0084) – 2014-2015
Expert services in support of Sierra Club's participation in integrated resource planning process.

Missouri Public Service Commission (File No. ER-2014-0258) – 2014-2015
Expert witness on behalf of the Sierra Club in Ameren Missouri rate case.

Arizona Corporation Commission (Docket No. E-01345A-11-0224) – 2014
Expert witness on behalf of the Sierra Club regarding Arizona Public Service petition for rate treatment for acquisition of an additional ownership share of the Four Corners generating units.

Missouri Public Service Comission (Docket No. ET-2014-0085) – 2013
Testimony on behalf of the Missouri Solar Energy Industries Association regarding Union Electric (d/b/a Ameren Missouri) motion to suspend payment of solar rebates.

Missouri Public Service Comission (Docket No. ET-2014-0059 and ET-2014-0071) – 2013
Testimony on behalf of the Missouri Solar Energy Industries Association regarding Kansas City Power and Light Company's motions to suspend payment of solar rebates.

Eastern Interconnect Planning Collaborative (EIPC) – 2012-2013
Expert support on behalf of coalition of NGO stakeholders in transmission and resource planning process, including development and review of modeling assumptions and interim results, and development of comments.

Puget Sound Energy (PSE) – 2012-2013
Expert participant in PSE's 2013 IRP stakeholder process on behalf of the Sierra Club.

Washington Utilities and Transportation Commission (Docket Nos. UE-111048 and UG-111049) – 2011
Testimony on behalf of the Sierra Club regarding the cost of operating the Colstrip power plant and other power procurement issues.

Kansas Corporation Commission (Docket No. 11-KCPE-581-PRE) - 2011
Presented written and live testimony on behalf of the Sierra Club regarding Kansas City Power and Light request for predetermination of ratemaking principles.

Vermont Department of Public Service - 2011
Provided scenario analysis of the costs and benefits of various electric energy resource scenarios in support of the state Comprehensive Energy Plan.

Massachusetts Department of Energy Resources – 2009-2011
Served as expert analyst and modeling coordinator for analysis related to implementation of the Massachusetts Global Warming Solutions Act.

Iowa Office of Consumer Advocate – 2010-2011
Assisted Consumer Advocate in evaluating a proposed power purchase agreement for the output of the Duane Arnold nuclear power station.

Missouri Public Service Commission (Docket No. EW-2010-0187) – 2010
Expert participant on behalf of the Sierra Club in stakeholder process to develop a "demand side investment mechanism" in Missouri.

Louisiana Public Service Commission (Docket No. R-28271 Subdocket B) – 2009-2010
Expert participant on behalf of the Sierra Club in Renewable Portfolio Standard Task Force considering RPS for Louisiana.

Joint Fiscal Committee of the Vermont Legislature – 2008-2010
Serving as lead expert advising the Legislature on economic issues related to the possible recertification of the Vermont Yankee nuclear power plant.

Town of Littleton, NH – 2006-2010
Serving as expert witness on the value of the Moore hydroelectric facility.

Nevada Public Service Commission (Docket No. 08-05014) – August 2008
Presented prefiled and live testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding the proposed Ely Energy Center and resource planning practices in Nevada.

Mississippi Public Service Commission (Docket No. 2008-AD-158) – July 2008
Presented written and live testimony on behalf of the Sierra Club regarding the resource plans filed by Entergy Mississippi and Mississippi Power Company.

Kansas House of Representatives - Committee on Energy and Utilities – February 2008
Presented testimony on behalf of the Climate and Energy Project of the Land Institute of Kansas on a proposed bill regarding permitting of power plants. Focus was on the risks and costs associated with new coal plants and on their contribute to global climate change.

Vermont Public Service Board (Docket No. 7250) – 2006-2008
Prepared report and testimony in support of the application of Deerfield Wind, LLC. For a Certificate of Public Good for a proposed wind power facility.

Iowa Utilities Board (Docket No. GCU-07-1) – October, 2007 – January 2008

Presented wrtten and live testimony on behalf of the Iowa Office of Consumer Advocate regarding the science of global climate change and the contribution of new coal plants to atmospheric CO_2.

Nevada Public Service Commission (Docket No. 07-06049) – October 2007
Presented prefiled direct testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding treatment of carbon emissions costs and coal plant capital costs in utility resource planning.

Massachusetts General Court, Joint Committee on Economic Development and Emerging Technologies – July 2007
Presented written and live testimony on climate change science and the potential benefits of a revenue-neutral carbon tax in Massachusetts.

Town of Rockingham, VT – 2006-2007
Served as expert witness on the value of the Bellows Falls hydroelectric facility.

South Dakota Public Utilities Commission (Case No EL05-22) – June 2006
Minnesota Public Utilities Commission (Docket TR-05-1275) – December 2006
Submitted prefiled and live testimony on the contribution of the proposed Big Stone II coal-fired generator to atmospheric CO_2, global climate change and the environment of South Dakota and Minnesota, respectively.

Arkansas Public Service Commission (Docket No. 06-070-U) – October 2006
Submitted prefiled direct testimony on inclusion of new wind and gas-fired generation resources in utility rate base.

Federal Energy Regulatory Commission (Docket Nos. ER055-1410-000 and EL05-148-000) – May-Sept 2006

- Participant in settlement hearings on proposed capacity market structure (the Reliability Pricing Model, or RPM) on behalf of State Consumer Advocates in Pennsylvania, Ohio and the District of Columbia
- Invited participant on technical conference panel on PJM's proposed Variable Resource Requirement (VRR) curve
- Filed Pre- and post-conference comments and affidavits with FERC
- Participated in numerous training and design conferences at PJM on RPM implementation.

Illinois Pollution Control Board (Docket No. R2006-025) – June-Aug 2006
Prefile and live testimony presented on behalf of the Illinois EPA regarding the costs and benefits of proposed mercury emissions rule for Illinois power plants.

Long Island Sound LNG Task Force – January 2006
Presentation of study on the need for and alternatives to the proposed Broadwater LNG storage and regasification facility in Long Island Sound.

Iowa Utilities Board (Docket No. SPU-05-15) – November 2005

Presented written and live testimony on whether Interstate Power and Light's should be permitted to sell the Duane Arnold Energy Center nuclear facility to FPLE Duane Arnold, Inc., a subsidiary of Florida Power and Light.

PUBLICATIONS AND REPORTS

Hausman, E., The Worst of Both Worlds: Why the Ohio Legislature's OVEC Bailout Bill would Harm Consumers, Impede Competition, Increase Pollution, and Impair the Health and Welfare of Ohioans for Decades. White paper produced on behalf of The Sierra Club, June 2017.

Hausman, E., Risks and Opportunities for PacifiCorp - State Level Findings: Utah, Produced on behalf of the Sierra Club, October 2014.

Hausman, E., Risks and Opportunities for PacifiCorp - State Level Findings: Oregon, Produced on behalf of the Sierra Club, October 2014.

Hausman, E., Risks and Opportunities for PacifiCorp in a Carbon Constrained Economy, Produced on behalf of the Sierra Club, October 2014.

Luckow, P., E. Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman, 2013 Carbon Dioxide Price Forecast, Synapse Energy Economics, November 2013.

Stanton, E., T. Comings, K. Takahashi, P. Knight, T. Vitolo, E. Hausman, Economic Impacts of the NRDC Carbon Standard: Background Report prepared for the Natural Resources Defense Council, Synapse Energy Economics for NRDC, June 2013

Comings T., P. Knight, E. Hausman, Midwest Generation's Illinois Coal Plants: Too Expensive to Compete? (Report Update) Synapse Energy Economics for Sierra Club, April 2013

Stanton E., F. Ackerman, T. Comings, P. Knight, T. Vitolo, E. Hausman, Will LNG Exports Benefit the United States Economy? Synapse Energy Economics for Sierra Club, January 2013

Chang M., D. White, E. Hausman, Risks to Ratepayers: An Examination of the Proposed William States Lee III Nuclear Generation Station, and the Implications of "Early Cost Recovery" Legislation, Synapse Energy Economics for Consumers Against Rate Hikes, December 2012

Wilson R., P. Luckow, B. Biewald, F. Ackerman, and E.D. Hausman, 2012 Carbon Dioxide Price Forecast, Synapse Energy Economics, October 2012.

Fagan B., M. Chang, P. Knight, M. Schultz, T. Comings, E.D. Hausman, and R. Wilson, The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region. Synapse Energy Economics for Energy Future Coalition, May 2012.

Hausman, E.D., T. Comings, "Midwest Generation's Illinois Coal Plants: Too Expensive to Compete? Synapse Energy Economics for Sierra Club, April 2012.

Hausman, E.D., T. Comings, and G. Keith, Maximizing Benefits: Recommendations for Meeting Long-Term Demand for Standard Offer Service in Maryland. Synapse Energy Economics for Sierra Club, January 2012.

Keith G., B. Biewald, E.D. Hausman, K. Takahashi, T. Vitolo, T. Comings, and P. Knight, Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011 Synpase Energy Economics for Civil Society Institute, November 2011.

Chang M., D. White, E.D. Hausman, N. Hughes, and B. Biewald, Big Risks, Better Alternatives: An Examination of Two Nuclear Energy Projects in the U.S. Synpase Energy Economics for Union of Concerned Scientists, October 2011.

Hausman E.D., T. Comings, K. Takahashi, R. Wilson, and W. Steinhurst, Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011. Synapse Energy Economics for Vermont Department of Public Service, September 2011.

Wittenstein M., E.D. Hausman, Incenting the Old, Preventing the New: Flaws in Capacity Market Design, and Recommendations for Improvement. Synapse Energy Economics for American Public Power Association, June 2011.

Johnston L., E.D. Hausman, B. Biewald, R. Wilson, and D. White. 2011 Carbon Dioxide Price Forecast. Synapse Energy Economics White Paper, February 2011.

Hausman E.D., V. Sabodash, N. Hughes, and J. I. Fisher, Economic Impact Analysis of New Mexico's Greenhouse Gas Emissions Rule. Synapse Energy Economics for New Energy Economy, February 2011.

Hausman E.D., J. Fisher, L. Mancinelli, and B. Biewald. Productive and Unproductive Costs of CO2 Cap-and-Trade: Impacts on Electricity Consumers and Producers. Synapse Energy Economics for National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Rural Electric Cooperative Association, and American Public Power Association, July 2009.

Peterson P., E. Hausman, R. Fagan, and V. Sabodash, Report to the Ohio Office of Consumer Counsel, on the value of continued participation in RTOs. Filed under Ohio PUC Case No. 09-90-EL-COI, May 2009.

Schlissel D., L. Johnston, B. Biewald, D. White, E. Hausman, C. James, and J. Fisher, Synapse 2008 CO2 Price Forecasts. July 2008.

Hausman E.D., J. Fisher and B. Biewald, Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation. Synapse Energy Economics Report to the Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, U.S. Environmental Protection Agency, July 2008.

Hausman E.D. and C. James, Cap and Trade CO2 Regulation: Efficient Mitigation or a Give-away? Synapse Enegy Ecomics presentation to the ELCON Spring Workshop, June 2008.

Hausman E.D., R. Hornby and A. Smith, Bilateral Contracting in Deregulated Electricity Markets. Synapse Energy Economics for the American Public Power Association, April 2008.

Hausman E.D., R. Fagan, D. White, K. Takahashi and A. Napoleon, LMP Electricity Markets: Market Operations, Market Power and Value for Consumers. Synapse Energy Economics for the American Public Power Association's Electricity Market Reform Initiative (EMRI) symposium, "Assessing Restructured Electricity Markets" in Washington, DC, February 2007.

Hausman E.D. and K. Takahashi, The Proposed Broadwater LNG Import Terminal Response to Draft Environmental Impact Statement and Update of Synapse Analysis. Synapse Energy Economics for the Connecticut Fund for the Environment and Save The Sound, January 2007.

Hausman E.D., K. Takahashi, D. Schlissel and B. Biewald, The Proposed Broadwater LNG Import Terminal: An Analysis and Assessment of Alternatives. Synapse Energy Economics for the Connecticut Fund for the Environment and Save The Sound, March 2006.

Hausman E.D., P. Peterson, D. White and B. Biewald, RPM 2006: Windfall Profits for Existing Base Load Units in PJM: An Update of Two Case Studies. Synapse Energy Economics for the Pennsylvania Office of Consumer Advocate and the Illinois Citizens Utility Board, February 2006.

Hausman E.D., K. Takahashi, and B. Biewald, The Glebe Mountain Wind Energy Project: Assessment of Project Benefits for Vermont and the New England Region. Synapse Energy Economics for Glebe Mountain Wind Energy, LLC., February 2006.

Hausman E.D., K. Takahashi, and B. Biewald, The Deerfield Wind Project: Assessment of the Need for Power and the Economic and Environmental Attributes of the Project. Synapse Energy Economics for Deerfield Wind, LLC., January 2006.

Hausman E.D., P. Peterson, D. White and B. Biewald, An RPM Case Study: Higher Costs for Consumers, Windfall Profits for Exelon. Synapse Energy Economics for the Illinois Citizens Utility Board, October 2005.

Hausman E.D. and G. Keith, Calculating Displaced Emissions from Energy Efficiency and Renewable Energy Initiatives. Synapse Energy Economics for EPA website 2005

Rudkevich A., E.D. Hausman, R.D. Tabors, J. Bagnal and C Kopel, Loss Hedging Rights: A Final Piece in the LMP Puzzle. Hawaii International Conference on System Sciences, Hawaii, January, 2005 (accepted).

Hausman E.D. and R.D. Tabors, The Role of Demand Underscheduling in the California Energy Crisis. Hawaii International Conference on System Sciences, Hawaii, January 2004.

Hausman E.D. and M.B. McElroy, The reorganization of the global carbon cycle at the last glacial termination. Global Biogeochemical Cycles, 13(2), 371-381, 1999.

Norton F.L., E.D. Hausman and M.B. McElroy, Hydrospheric transports, the oxygen isotope record, and tropical sea surface temperatures during the last glacial maximum. Paleoceanography, 12, 15-22, 1997.

Hausman E.D. and M.B. McElroy, Variations in the oceanic carbon cycle over glacial transitions: a time-dependent box model simulation. Presented at the spring meeting of the American Geophysical Union, San Francisco, 1996.

PRESENTATIONS AND WORKSHOPS

American Public Power Association: Invited expert participant in APPA's roundtable discussion of the current state of the RTO-operated electricity markets. October 2013.

California Long-Term Resource Adequacy Summit (Sponsored by the California ISO and the California Public Utility Commission): Panelist on "Applying Alternative Models to the California Market Construct." February 26, 2013.

ELCON 2011 Fall Workshop: "Do RTOs Need a Capacity Market?" October 2011.

Harvard Electricity Policy Group: Presentation on state action to ensure reliability in the face of capacity market failure. February 2011.

NASUCA 2010 Annual Conference: "Addressing Climate Change while Protecting Consumers." November 2010.

NASUCA Consumer Protection Committee: Briefing on the Synapse report entitled, "Productive and Unproductive Costs of CO_2 Cap-and-Trade." September 2009.

NARUC 2009 Summer Meeting: Invited speaker on topic: "Productive and Unproductive Costs of CO2 Cap-and-Trade." July, 2009.

NASUCA 2008 Mid-Year Meeting**:** Invited speaker on the topic, "Protecting Consumers in a Warming World, Part II: Deregulated Markets." June 2008.

Center for Climate Strategies: Facilitator and expert analyst on state-level policy options for mitigating greenhouse gas emissions. Serve as facilitator/expert for the Electricity Supply (ES) and Residential, Commercial and Industrial (RCI) Policy Working Groups in the states of Colorado and South Carolina. 2007-2008.

NASUCA 2007 Mid-Year Meeting**:** Invited speaker on the topic, "Protecting Consumers in a Warming World" June 2007.

ASHRAE Workshop on estimating greenhouse gas emissions from buildings in the design phase: Participant expert on estimating displaced emissions associated with energy efficiency in building design. Also hired by ASHRAE to document and produce a report on the workshop. April, 2007.

Assessing Restructured Electricity Markets An American Public Power Association Symposium: Invited speaker on the history and effectiveness of Locational Marginal Pricing (LMP) in northeastern United States electricity markets, February, 2007.

ASPO-USA 2006 National Conference: Invited speaker and panelist on the future role of LNG in the U.S. natural gas market, October, 2006.

Market Design Working Group: Participant in FERC-sponsored settlement process for designing capacity market structure for PJM on behalf of coalition of state utility consumer advocates, July-August 2006.

***NASUCA 2006 Mid-Year Meeting*:** Invited speaker on the topic, "How Can Consumer Advocates Deal with Soaring Energy Prices?" June 2006.

Soundwaters Forum, Stamford, CT: Participated in a debate on the need for proposed Broadwater LNG terminal in Long Island Sound, June 2006.

Energy Modeling Forum: Participant in coordinated academic exercise focused on modeling US and world natural gas markets, December 2004.

Massachusetts Institute of Technology (MIT): Guest lecturer in Technology and Policy Program on electricity market structure, the LMP pricing system and risk hedging with FTRs. 2002-2005.

LMP: The Ultimate Hands-On Seminar. Two-day seminar held at various sites to explore concepts of LMP pricing and congestion risk hedging, including lecture and market simulation exercises. Custom seminars held for FERC staff, ERCOT staff, and various industry groups. 2003-2004.

Learning to Live with Locational Marginal Pricing: Fundamentals and Hands-On Simulation. Day-long seminar including on-line mock electricity market and congestion rights auction, December 2002.

LMP in California. Led a series of seminars on the introduction of LMP in the California electricity market, including on-line market simulation exercise. 2002.

Resume updated May 2020

Exhibit EDH-2

Jim Lazar (2015). Smart Rate Design for a Smarter Future, Appendix D: The Specter of Straight Fixed/Variable Rate Designs and the Exercise of Monopoly Power. Regulatory Assistance Project.

Smart Rate Design for a Smart Future, Appendix D

The Specter of Straight Fixed/Variable Rate Designs and the Exercise of Monopoly Power

By Jim Lazar

Introduction

A number of electric utilities have proposed what is called "straight fixed/variable" rate design (SFV), in which all costs claimed to be "fixed costs" are recovered in a fixed monthly charge, and only those costs that are considered "variable" are recovered on a per kilowatt-hour (kWh) basis. While most have focused only on distribution costs, a few have gone further, proposing that generation and transmission investment-related costs be included in monthly fixed charges.[1]

In accounting terms, the only truly "fixed" costs are interest and depreciation. All other costs, including the shareholder return, associated income taxes, labor, and revenue-sensitive costs are technically "variable" costs — they change from month to month and from year to year. Utilities often define "fixed costs" very loosely, including these other costs, as well as all distribution costs and sometimes even some generation-related costs in this category.

High fixed charges provide utilities with stable revenues, but have many adverse impacts on electric consumers and energy policy. We discuss some of these below.

Disincentives to Public Policy Goals

Energy Efficiency

Given a defined electric revenue requirement, a higher fixed charge results in a lower per kWh rate. Table D-1 shows an illustrative example, comparing a utility with a typical customer charge of $7.00/month and a $.10/kWh energy charge with one imposing a $57/month customer charge, but only a $.05/kWh energy charge. Both have the same bill — $107.00/month — for the average customer, but the higher customer charge results in a 44% larger bill for a typical apartment dweller or other small user, and a savings of 29% for a very large home.

Table D-1

Example of Fixed Charge Effect

Rate Design		Typical Rate	SFV Rate	Difference
Customer Charge		$7.00	$57.00	
Energy Charge		$0.10	$0.05	
Customer Bills	**kWh/month**			
Average Customer	1000	$107.00	$107.00	0%
Apartment Dweller	500	$57.00	$82.00	44%
Extra-Large Residence	2500	$257.00	$182.00	-29%

The impact of this on customer-driven energy efficiency can be quite dramatic. A high-efficiency air conditioner or window replacement that might have a 5-year payback period for the consumer at $.10/kWh would have a 10-year payback at $.05/kWh. Many consumers will be hesitant to invest in energy efficiency if the savings are smaller.

Competitive Impact on Renewable Energy Development

The same adverse effect can result for customer renewable energy development. A customer who might invest in a solar photovoltaic system when they can avoid $.10/kWh in the utility rate may be able to put together a combination of tax incentives and financing to make this an attractive investment. At $.05/kWh, it is much less likely. At the same time, a low-use (high efficiency plus on-site solar) custom-

1 For example, Madison Gas and Electric in 2014 proposed a $57/month fixed charge, and Hawaiian Electric Company proposed a $55/month fixed charge, plus an additional $16/month for customers with photovoltaic systems. The MG&E proposal was resolved with a $19/month customer charge, and the HECO proposal was significantly modified to a $25 monthly minimum bill, and a lower credit of only $0.18/kWh for excess solar energy exported to the grid from new PV installations.

er considering going off the utility grid would have a much stronger incentive to do so. The cost of their storage bank would only need to compete with the high fixed cost attributable to the average customer, but since they produce much of their power on-site, they would need a smaller than average storage capacity to store a portion of their power needs. The customer, of course, would then be obligated to supply all his/her power needs. Losing a customer permanently further exacerbates the lost revenue issue.

Low-Income Households

The vast majority of low-income households use below-average amounts of electricity, and will pay higher bills with an SFV rate design. Table D-2 shows an analysis prepared

Table D-2

Low-Income Household Usage

Average 2009 household electricity usage (kWh) by status above or below 150% of poverty

Energy Information Administration, Residential Energy Consumption Survey Reportable Domain	Average Usage (kWh) Sorted by Income Level			Percentage Difference Between Average KWH Low-Income and Non-Low-Income Households
	Above 150% Poverty Level	At or Below 150% Poverty Level	All Households	
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	8,453	5,920	7,940	**-30.0%**
Massachusetts	7,364	5,353	6,967	**-27.3%**
New York	7,039	5,431	6,578	**-22.8%**
New Jersey	9,155	6,760	8,902	**-26.2%**
Pennsylvania	10,733	8,992	10,402	**-16.2%**
Illinois	10,771	9,430	10,392	**-12.5%**
Indiana, Ohio	11,559	10,224	11,220	**-11.6%**
Michigan	9,206	7,508	8,695	**-18.4%**
Wisconsin	8,827	7,961	8,672	**-9.8%**
Iowa, Minnesota, North Dakota, South Dakota	11,288	8,198	10,719	**-27.4%**
Kansas, Nebraska	10,800	10,030	10,633	**-7.1%**
Missouri	13,775	13,602	13,740	**-1.3%**
Virginia	15,088	11.237	14,442	**-25.5%**
Delaware, District of Columbia, Maryland, West Virginia	14,437	12,711	14,100	**-12.0%**
Georgia	15,452	13,823	14,917	**-10.5%**
North Carolina, South Carolina	14,717	12,620	14,045	**-14.2%**
Florida	15,679	12,358	14,858	**-21.2%**
Alabama, Kentucky, Mississippi	16,307	12,915	15,236	**-20.8%**
Tennessee	15,766	13,512	15,132	**-14.3%**
Arkansas, Louisiana, Oklahoma	14,852	13,560	14,392	**-8.7%**
Texas	15,157	11,816	14,277	**-22.0%**
Colorado	7,745	5,752	7,439	**-25.7%**
Idaho, Montana, Utah, Wyoming	11,349	13,126	11,753	**15.7%**
Arizona	14,970	11,218	14,105	**-25.1%**
Nevada, New Mexico	10,580	9,643	10,369	**-8.9%**
California	7,256	5,732	6,888	**-21.0%**
Alaska, Hawaii, Oregon, Washington	12,841	11,726	12,570	**-8.7%**
Total	**11,734**	**10,692**	**11,320**	**-14.2%**

by the National Consumer Law Center that examines the usage of low-income households. It shows that households below 150% of the federal poverty level use between 9% and 30% less electricity than the average of all households.

However, there are some low-income households with high electricity usage, including large (sometimes multigenerational) households, but in most cases this is the result of low levels of energy efficiency that can be addressed with programmatic conservation. In general, low-income advocates, consumer advocates, and environmental advocates favor addressing the special needs of these families with specific programmatic approaches or direct financial assistance, rather than setting a base rate design that favors high-users.[2]

Apartment and Urban Dwellers

Multi-family housing residents also have below-average usage and are adversely impacted by high fixed charge rate designs. These residents typically have below-average dwelling size, below-average residents per household, and below-average usage. They are also quite obviously cheaper to provide electric distribution service to — since they are close together and many customers are served by a single distribution transformer. As we discuss in Chapter IV, this has many impacts on the cost of utility service and appropriate rate design.

SFV Can Cause a 15% Increase in Electric Consumption

When Madison Gas & Electric originally proposed a $69/month customer charge, it also proposed reducing the per kWh rate from $.14/kWh in winter and $.15/kWh in summer to about $.04/kWh. Using the economic principle of elasticity (higher prices result in a lower quantity demanded), and applying a moderate elasticity factor of -0.2 (a 1% increase in price results in a 0.2% reduction in usage), The Regulatory Assistance Project estimated that the proposed rate design could result in about a 14.5% increase in usage over time.[3] The expectation is that consumers would raise thermostats, defer efficiency investments, and be less attentive to simple things like turning off unused lights.

Other Potential Adverse Impacts

A utility with a high fixed monthly charge may invite several kinds of undesirable and even dangerous behaviors by consumers.

Risky connections in Delhi, India

The first of these is informal master-metering, where more than one household is served through a single meter. This can happen when houses are divided into a primary residence and an accessory dwelling unit (mother-in-law apartment). However, if the monthly fixed charge is low, the owner will normally have a second meter installed for the second dwelling so that both occupancies pay for their own electricity. These type of "ohana" (extended-family) units account for as much as 15% of the housing stock in parts of Hawaii.

The second is more dangerous: connecting multiple dwellings together with less-than-utility-grade wiring. This is very common in some countries, and creates safety risks for residents and reliability risks for the electric distribution system (see photo from India).

Third, high fixed monthly charges may result in some seasonal consumers completely disconnecting service during part of the year. This actually increases costs for utilities, since they must handle the customer service call twice. At the same time it inconveniences the consumer. The electric distribution system is unchanged during this period when service to individual customers is

2 Testimony of John Howat, National Consumer Law Center, Wisconsin PSC Docket No. 3270-UR-120.

3 For an explanation of how rate design and elasticity affects usage, see Lazar, J. (2013). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed*, Appendix A. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6516

suspended. Some utilities have responded by imposing high reconnection charges when the customer initiates service, but this may also adversely affect rental properties where move-in / move-out changes of service are common, and often involve lower income consumers. As in other situations involving low-use customers, the electric distribution system is not changed by the coming or going of an individual consumer.

Principle: Customers Should Be Able to Connect to the Grid at Reasonable Cost

Based on the discussion in the early chapters of "Smart Rate Design for a Smart Future," we derived our first principle of electricity pricing:

A customer should be able to connect to the grid for no more than the cost of connecting to the grid: This should reflect only those costs to the system that the *addition* of the customer adds, such as billing and metering, not the distribution infrastructure.

The Foundation of Regulation Is the Prevention of the Exercise of Monopoly Power

The imposition of a fixed charge for the privilege of being a customer is almost non-existent in the competitive world. Oil refineries, hotels, airlines, and supermarkets have significant fixed costs, including building and equipment. Even their labor costs do not vary directly with sales volumes. But all of these recover all their fixed and variable costs through volumetric prices. In a competitive environment, it is essentially impossible to charge a customer for the privilege of being a customer. In fact, we find quite the opposite — special discounts offered to attract new customers, to try to build a business relationship that will then continue over time.

The original purpose of public service company regulation was to prevent the exercise of pricing power by businesses that had a local monopoly over service. The earliest of these were the regulations imposed on overnight lodging in medieval England, while the modern framework of utility regulation in the United States began with railroads and associated businesses.

Munn vs. Illinois

One landmark case involved a grain elevator operator who owned the only facilities that farmers could use to load their products onto the railroads. The alternative was to haul the grain a long distance, not an easy proposition in the era of horse-drawn wagons.

In Munn v. Illinois, the US Supreme Court ruled that businesses "affected with the public interest" could be subject to regulation by states. In that decision, the Court stated:

> *"In countries where the common law prevails, it has been customary from time immemorial for the legislature to declare what shall be a reasonable compensation under such circumstances, or perhaps more properly speaking, to fix a maximum beyond which any charge made would be unreasonable."*[4]

This principle evolved over time to give state utility regulators the authority to fix the specific tariffs for electric service, and most state laws require that these be "fair, just, and reasonable" or similar subjective legislative criteria. This prevented the exercise of monopoly pricing power over consumers who had no other utility available to them.

Where utilities are allowed to impose high fixed monthly charges, this becomes an exercise of monopoly pricing power. As Charles Cicchetti, former chairman of the Wisconsin Public Service Commission, recently stated with respect to the Wisconsin Electric Power Company proposal to recover its generation, transmission, and distribution investment-related costs in fixed monthly charges:

> *"WEPCO invokes mostly outdated and previously rejected logic in an attempt to convince the Commission to let it use its utility monopoly and mostly very limited customer choice to force customers to absorb risks in an unjust and unreasonable manner, which is contrary to economic and public policy objectives."*[5]

Imparting to Natural Monopolies the Pricing Discipline That Is Imposed By Competitive Markets

Another important role of utility regulation is to impart to natural monopolies (as electric distribution utilities are generally categorized) the same pricing discipline that competitive firms experience, so that they endeavor to minimize costs and maximize customer satisfaction. If utilities are allowed to recover their system costs in fixed charges for the privilege of being a customer, much of this discipline is lost. Conversely, if they recover their costs in

4 Munn v. Illinois, 94 U.S. 113 (1877)

5 Testimony of Charles Cicchetti, Wisconsin Public Service Commission, Docket No. 05-UR-107 (2014), p. 25.

the per kWh price, they must compete with alternatives to electricity consumption from the utility, including energy efficiency and customer self-generation. This discipline helps to hold costs down for all consumers.

Universal Service Policies

Universal access to electricity service has long been recognized as desirable for social, health, safety, and other reasons. In the United States, electric utilities expanded service to urban areas and to large businesses in the late years of the 19th century, but at the time of the great depression most rural areas were still without electric service because the cost to expand distribution systems was not profitable.

The Congress responded by creating the Rural Electrification Administration (REA, now the Rural Utility Service or RUS) to help expand electricity to rural areas.[6] Lyndon Johnson's first campaign for Congress in 1936 had as a key campaign issue to secure electricity service for rural Texas; he came from an area now served by the Pedernales Electric Cooperative, headquartered in Johnson City. The REA provided interest-free loans and grants to help make universal service to smaller communities possible. The electrification of these communities was viewed as important to help these communities survive and prosper.

The United Nations Secretary General's Advisory Group on Energy and Climate Change[7] has set a goal to extend basic electricity service to 99% of the population of the world. The definition of "basic" service includes provision of lighting (so that students can continue their studies after sunset) and refrigeration (to reduce food-borne illness). The level of consumption is 50 kWh per month per person to meet these basic needs. In the United States and other developed countries, the "basic" needs level of service is higher than the developing world figure used by the UN, on the order of 300–400 kWh/month/household.

SFV rate design strikes directly at universal service, because it makes electricity service, even for the most basic and essential uses, unaffordable to low-income households. It does this (even if they are densely located in urban areas where distribution costs are very low), by averaging their cost of service with suburban and rural areas where per customer distribution costs are very different. In effect, under SFV pricing, low-income households are made to subsidize higher-income, higher-usage households.

Regulate Price Where Competitive Market Does Not Exist to Set Price

Finally, a key role of utility regulation is to set prices where a competitive market does not exist to impose prices on suppliers. Electricity distribution service remains such an area of commerce in nearly all communities in the United States. The role of the regulator is to implement prices equivalent to what would be charged by a competitive market, were one present.

As we discuss below, in other competitive markets the monthly charge for "connection to the system" is usually zero, and even where it is greater than zero it is normally very small.

The Relationship Between Fixed Costs and Fixed Charges

Utilities often argue that the majority of their costs are fixed, and extrapolate from this that these fixed *costs* should be recovered in fixed *charges*. This is lacking in both economic foundation and accounting principles:

Just because a cost is fixed in the short run does not mean it should be recovered in a fixed charge.

Utilities often assert that most of their costs are "fixed" and should be recovered in fixed charges. While interest and depreciation expense are fixed in the short run, virtually every other cost is variable even in the short run.

Even if a cost is "fixed" it does not mean it should be recovered in a fixed charge. Investments in power plants are made to provide a supply of electricity, and the costs should be recovered in proportion to how much of that production a customer uses (this is discussed in Chapter V of the main text, when considering the various dimensions of usage that are measured and priced). Transmission facilities are built to connect remote power plants to the communities needing power, and are essentially an alternative to building those power plants directly in the community.

The decision to build distribution systems is made where

6 For detail on the RUS, see: http://www.rd.usda.gov/about-rd/agencies/rural-utilities-service.

7 Energy for Sustainable Future, the Secretary-General Advisory Group on Energy and Climate Change, United Nations Industrial Development Organization, 2010.

there is a sufficient market to justify the cost, not based on how much each individual consumer will use or how many consumers will be served. Nearly every utility has a "line extension policy" that dictates where the utility will build distribution facilities, and under what circumstances the customers seeking service must pay for the line extension. A circuit serving 10 large customers, each using 100,000 kWh/month will attract investment as easily as a circuit serving 1,000 customers each using 1,000 kWh/month. All of these investments have elements of fixed costs, but this does not mean they should be recovered in fixed charges.

Utility labor costs are often thought of as fixed in the short-run, but during the 2008 economic crisis some utilities reduced staffing by as much as 10% to preserve earnings in the face of sharp reductions in industrial activity. In a financial crisis, maintenance is deferred, customer service quality is impaired, and even administrative costs are cut.

There is a sound argument that individual customers should pay the direct costs of their customer-specific costs. Historically, this has been interpreted by many utility regulators as the cost of meters, service drops, meter reading, billing, and collection. These costs are normally calculated in the range of $5–$10/month, but even the meter reading, billing, and collection costs are variable costs that are a function of how often bills are rendered. The additional cost of smart meters is justified by many benefits beyond the simple measurement of usage (see Chapter IV of the main text), and this additional cost is not properly considered customer-related. The primary reason for monthly billing is not to collect the $5–$10/month in customer-specific costs, but to collect the $50–$150/month in electricity usage charges; if usage were very small, quarterly billing would be adequate. Thus, even these monthly billing costs are related to usage.

A recent posting by Severin Borenstein, professor and director emeritus of the University of California Energy Institute, addresses this in detail, and utterly discredits the suggestion that fixed costs should translate into fixed charges. He states:

> *But the mere existence of system wide fixed costs doesn't justify fixed charges. We should get marginal prices right, including the externalities associated with electricity production. We should use fixed charges to cover customer-specific fixed costs. Beyond that, we should think hard about balancing economic efficiency versus fairness when we use additional fixed charges to help address revenue shortfalls.*[8]

A cost-based fixed charge recovers those costs that vary with the number of customers.

The debate in rate design as to what costs belong in the monthly customer charge often follows on the related debate in cost allocation as to which costs are customer-related in nature. While some regulators have allowed distribution infrastructure costs to be classified as customer-related, most have directed that only customer-specific costs be classified as customer-related, and it follows that only those customer-specific costs be included in the monthly fixed customer charge.

These issues were heavily debated in most states during the PURPA proceedings of 1978–1982, and most states resolved these issues in favor of a narrow definition of customer-related costs. Most regulators have adhered to these principles since.

For example, the Illinois PUC recently ruled that the mere fact that costs are "fixed" in some short-term sense should not guide rate design:

> *"The Companies' proposed SFV rate design diverges from cost-causation, substituting its "fixed" cost designation for cost causation as the determinative allocator. …*
>
> *"By failing to send proper price signals, the Companies' proposed rate design denies consumers who conserve the benefit of their actions, and punishes customers who are frugal. The proposed SFV charges are indifferent to efficiencies in usage and demand. In contrast, the Commission has recognized that lower monthly customer charges and higher volumetric charges can advance energy use conservation and efficiency policy objectives by providing a greater price signal.*
>
> *"The Commission finds that Staff's and Intervenor's arguments in favor of assigning demand-based costs to volumetric charges are consistent with energy efficiency and the avoidance of cross subsidies."*[9]

Calculated Example

It is relatively straightforward to calculate an example of how customer-related costs translate into customer charges that are cost-based, and recover only customer-specific costs in per-customer fixed charges; see Table D-3.

8 Borenstein, S. (2014, November 3). *What's So Great About Fixed Charges?* See https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/

9 Illinois Commerce Commission, People's Gas, Docket 14-0224, 2015.

Table D-3

Calculated Example

Calculation of Per-Customer Costs	
Service Drops	$100,000
Meters	$100,000
Subtotal Rate Base	$200,000
Allowed Return With Taxes	12%
Allowed Return	$24,000
Depreciation Expense	$8,000
Subtotal Capital Costs	$32,000
Meter and Service Maintenance	$5,000
Billing and Collection Costs	$25,000
Subtotal Operating Costs	$30,000
Total Customer-Related Costs	$62,000
Customers Serviced	1,000
Annual Cost/Customer	$62.00
Monthly Cost/Customer	$5.17

Figure D-1

Unbundled vs. Bundled Pricing for Gasoline

Crude Oil	$2.237
Tanker to Refinery	$0.114
Refinery Capital	$0.213
Refinery Operating	$0.235
Product Pipeline	$0.113
Terminal Rack	$0.023
Truck to MiniMart	$0.114
MiniMart Profit	$0.217
State Taxes	$0.349
Federal Taxes	$0.184

How Competitive Markets Address The Fixed Cost/Fixed Charge Issue

A principal purpose of regulation is to impose on natural monopolies the same discipline that competitive firms face in setting unregulated prices. Every business has costs that are fixed in the short run, and every profitable firm recovers these in a manner that enables them to attract customers and price their product effectively to address competitive pressure. In almost all cases, the result is that fixed costs are recovered volumetrically.

Gasoline

American consumers spend about the same proportion of their income on gasoline as on electricity, but gasoline trades in a competitive, largely unregulated market. The entire gasoline supply stream involves immense investments that are at least as "fixed" as electric utility distribution systems. Oil wells involve huge drilling expense. Oil tankers are very expensive. Oil refineries cost billions of dollars to build. The pipeline network that brings the crude oil to the refineries, and the product pipelines that move finished products from the refineries to the communities where it is consumed are fixed assets. Even the local oil terminal, tanker trucks, and service stations or mini-marts involve extensive investment.

These costs are all recovered in a single price per gallon of gasoline at the pump, and no attempt is made to impose a separate "subscription" charge from the usage charge, or to separate out (itemize or unbundle) the cost of gasoline. Customers compare stations based on the ultimate price per gallon (and other factors, including brand, convenience, and real or perceived differenced in quality) on a basis that combined all fixed and variable costs into a single price per gallon.

Think about which of the two pricing approaches in Figure D-1 is most useful to you in making a gasoline purchase decision comparing two gas stations.

Groceries

Consumers spend even more of their budget on groceries than on gasoline or electricity. Like gasoline, the grocery supply chain is immense, bringing products from around the globe to a supermarket near where we live. Supermarkets do not charge admission fees and, except in dense urban areas, provide free parking completely independent of how much a customer spends. However, prices are slightly different depending on how the customer "connects to the grocery grid." A large chain like Kroger, Albertson's, or Wal-Mart has lower prices than a neighborhood mini-mart — but the customer incurs the cost of traveling to the supermarket to secure those lower prices. In essence, they bear the cost of connecting to the "grocery grid" at a more centralized point. But in both cases the fixed (and variable) costs of the grocer are reflected in the per-unit prices of their products. We discuss membership stores such as Costco and Sam's Club separately.

Membership Discount Stores: They DO Charge to "Be a Customer"

Membership stores like Costco and Sam's Club DO charge a "membership fee" for customers to gain admission. They do this for a simple reason: to reduce the number of "shoppers" versus "buyers" in their stores, in order to increase the volume of product that can be sold from a given store size.

In essence, these stores provide consumers an opportunity to "connect to the grid" at a wholesale level, rather than a retail level.

However, even for these stores, the membership fee reflects a very small portion of annual revenues, about 2%–4%; for an electric utility that would equate to a customer charge of $2/month to $4/month, based on an average monthly bill nationally of about $100/month.

But even the membership fee may be rebated. Costco has two membership tiers, $55/year and $110/year for "Executive" membership. The Executive membership comes with a 2% annual rebate on purchases — and is marketed by Costco to their larger consumers. Most Executive members receive rebates that approximate or exceed their annual membership dues.

In addition, virtually every product available from a membership store is also available (generally in smaller package sizes) at supermarkets or discount stores like Target and Wal-Mart, without a membership fee. Consumers who do not buy enough to justify the membership fee can easily avoid it, unlike electric consumers who do not have a realistic alternative to the electric utility service.

The electricity service equivalent would be if a customer built their own connection to the utility at the primary voltage level — and then would pay a much lower price (as large industrial consumers do) for their service. Customers that connect to the grocery grid at the "distribution" level of their neighborhood supermarket pay slightly higher prices than at warehouse stores.

Hotels

Large hotels often involve tens of millions of dollars of investment (into the billions for destination mega-resorts.) They recover these costs on a per-room per-day basis. But they employ sophisticated pricing models in doing so, varying pricing based on demand for rooms, season of the year, and with discounts for large-volume buyers (convention rates). We will not defend the lack of transparency in hotel pricing, but will note that search tools like Hotwire, Priceline, and Trivago have made it possible for individual consumers to receive many of the pricing advantages that larger buyers achieve.

The dynamic pricing for hotel rooms (and for airline tickets and rental cars) has been the foundation on which many proposals for electric dynamic pricing (see discussion in main paper) have been based.

Making Electricity Pricing Comparable

To make electricity pricing comparable to that for gasoline, groceries, or hotel rooms would not actually be very difficult. First, different prices based on where the customer connects to the grid would be developed; most utilities already have these, with separate rates for customers served at secondary, primary, and transmission voltage. Next, the prices for all electricity would be on a volumetric basis, but differentiated by time of day, season of year, geographic zone, and with dynamic elements that would raise prices when electricity is scarce and discount it when it is at risk of being wasted. This is discussed in Chapter V of the main tect.

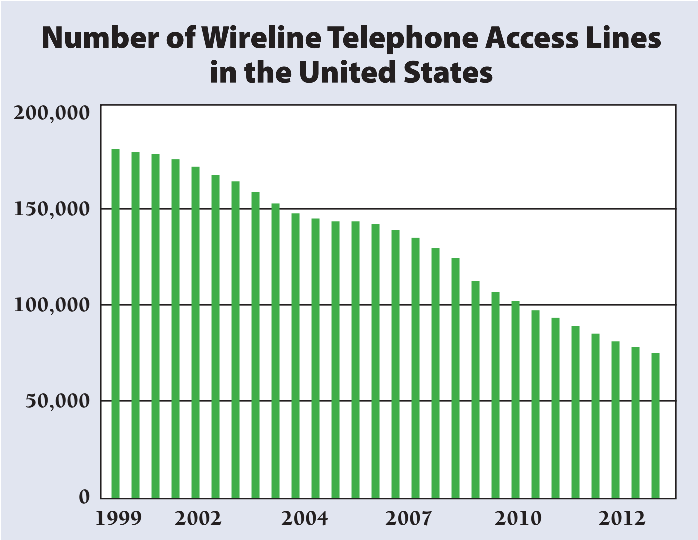
The Experience with Telecom

Some analysts point to the telecommunications industry as an example in which consumers pay high monthly fixed charges for cellular "plans" and pricing is not volumetric. This is somewhat inaccurate, and the history of telecommunications deregulation is instructive for some potential pitfalls of high fixed-charge pricing for electricity.

Prior to 1980, telephone companies were integrated providers of local and long-distance phone service. Each long-distance call contributed a few cents per minute to the local carrier, and this allowed the per-month rates for basic telephone service to be very low.

When long-distance competition began in the 1980s, customers needed to use "dial-around" systems to reach competitive services. They would dial a local number to a competitive carrier, dial in additional information, and the competitive carrier would connect the call to the destination city and place a local call there to make the connection. Large companies installed sophisticated "least

Figure D-2



cost routing" systems to do this automatically. These had a modest impact on the financial health of local exchange carriers (traditional phone companies).

Later, federal policy required local exchange carriers to allow customers to choose their long-distance carrier. At that time, an "access charge" was imposed at the federal level to compensate local carriers for a portion of the lost revenues, "termination fees" were imposed so the receiving phone company received compensation for delivering the connection at the receiving end, and long-distance prices dropped sharply.

This proved inadequate to replace all of the lost margins, and local exchange carriers petitioned state regulators to sharply increase their monthly fixed charges. In many parts of the county, the combined effect of the local rate design and the federal access charges raised the monthly fixed charge for telephone service from about $6/month to $30/month or more. The result has been dramatic: local exchange carriers have lost more than half of their customer access lines.

Does this mean that customers are making and receiving fewer calls? Certainly not. Or are less able to transmit documents, or access data services? Hardly. All of these services have moved to competitive suppliers, and in parts of the country local exchange carriers are abandoning territory and facing financial distress. The local exchange carriers have effectively priced themselves out of traditional markets with high fixed charges.

Some of these carriers have been successful by building fiber optic systems to deliver high-speed Internet, television, and other content. By bundling services together, they have built viable business models. But other competitors have entered the market to provide low-cost basic telephone service.

- Tracfone provides cellular service for as little as $7/month, including voice, text, voicemail, and even Internet service — on a pay-per-minute basis, with approximately 1,000 minutes per year provided on an "annual plan" available through discounters. Other prepaid cellular companies include Virgin Mobile, Cricket, and Consumers Cellular.
- Straighttalk provides both cellular and voice-over-internet-protocol (VOIP) service, with unlimited calling for $10–$15 per month, marketed through Wal-Mart stores.
- Magic-Jack provides VOIP service for as little as $50/year with unlimited calling for those with broadband Internet access.
- Skype provides local and long-distance unlimited VOIP service for as little as $25/year, including video communication and video conferencing.
- Federally subsidized "lifeline" phone service for low-income households is migrating from fixed line to cellular service, in part to avoid high fixed-line charges.

Many telephone services are now offered on a fully bundled "all-you-can-eat" basis. These are attractive to high-use customers, and sometimes chosen by less knowledgeable small users. But competitive firms offering service with very low fixed fees are widely available.

Addressing Revenue Stability Concerns

Electric utilities companies are concerned about rate design in part because under traditional volumetric rate design declining sales results in declining profits. This is a real issue. A study prepared on one electric utility showed that a 2% decline in sales would result in a 24% reduction in net earnings.

There are many ways to address revenue stability issues, and high monthly fixed charges are probably the worst option from a customer impact perspective. A discussion of several alternatives follows.

Table D-4

Impact on Earnings of Sales Decline for Illustrative SW Electric Utility[10]

% Change in Sales	Revenue Change		Impact on Earnings		
	Pre-tax	After-tax	Net Earnings	% Change	Actual ROE
5.00%	$9,047,538	$5,880,900	$15,780,900	**59.40%**	17.53%
4.00%	$7,238,031	$4,704,720	$14,604,720	**47.52%**	16.23%
3.00%	$5,428,523	$3,528,540	$13,428,540	**35.64%**	14.92%
2.00%	$3,619,015	$2,352,360	$12,252,360	**23.76%**	13.61%
1.00%	$1,809,508	$1,176,180	$11,076,180	**11.88%**	12.31%
0.00%	$0	$0	$9,900,000	**0.00%**	11.00%
-1.00%	-$1,809,508	-$1,176,180	$8,723,820	**-11.88%**	9.69%
-2.00%	-$3,619,015	-$2,352,360	$7,547,640	**-23.76%**	8.39%
-3.00%	-$5,428,523	-$3,528,540	$6,371,460	**-35.64%**	7.08%
-4.00%	-$7,238,031	-$4,704,720	$5,195,280	**-47.52%**	5.77%
-5.00%	-$9,047,538	-$5,880,900	$4,019,100	**-59.40%**	4.47%

Revenue Regulation

Most utility regulators set prices for electricity, and let revenues float as sales volumes deviate from assumed levels. An alternative, revenue regulation (or "decoupling"), works differently: the regulator sets an allowed level of revenue and periodically allows minor adjustments in prices to ensure the utility recovers the allowed revenue. More than half of the US states have employed some form of this, as shown in Figure D-3.

Incentive Regulation

A number of regulators have adopted various forms of incentive regulation to reward utilities for strong efforts to achieve energy efficiency. These "performance-based regulation" (PBR) frameworks can reward any number of desired utility performance indicators, including lower sales per customer. It is also possible to combine a PBR mechanism with decoupling.[11]

Weather Normalization

Utility sales vary with weather and, for many, this is the single largest driver of month-to-month net income. A weather adjustment simply adjusts prices periodically, usually monthly, to address abnormal weather. These are relatively common for natural gas utilities.

Reserve Accounts

Some regulators, primarily municipal utility authorities, create specific reserve accounts to be drawn on when sales are below expected levels (or sometimes when expenses are above expected levels). These are quite common for hydroelectric-based utilities, where there are wet years and dry years and the power supply costs can vary dramatically.

All of these approaches leave the basic utility rate design unaffected. The total cost of service can still be reflected in an easy-to-understand volumetric price. The utility's revenue is augmented when sales fall below expected levels. Other approaches are less desirable from an energy efficiency and customer impact perspective, but may also provide utility revenue stability.

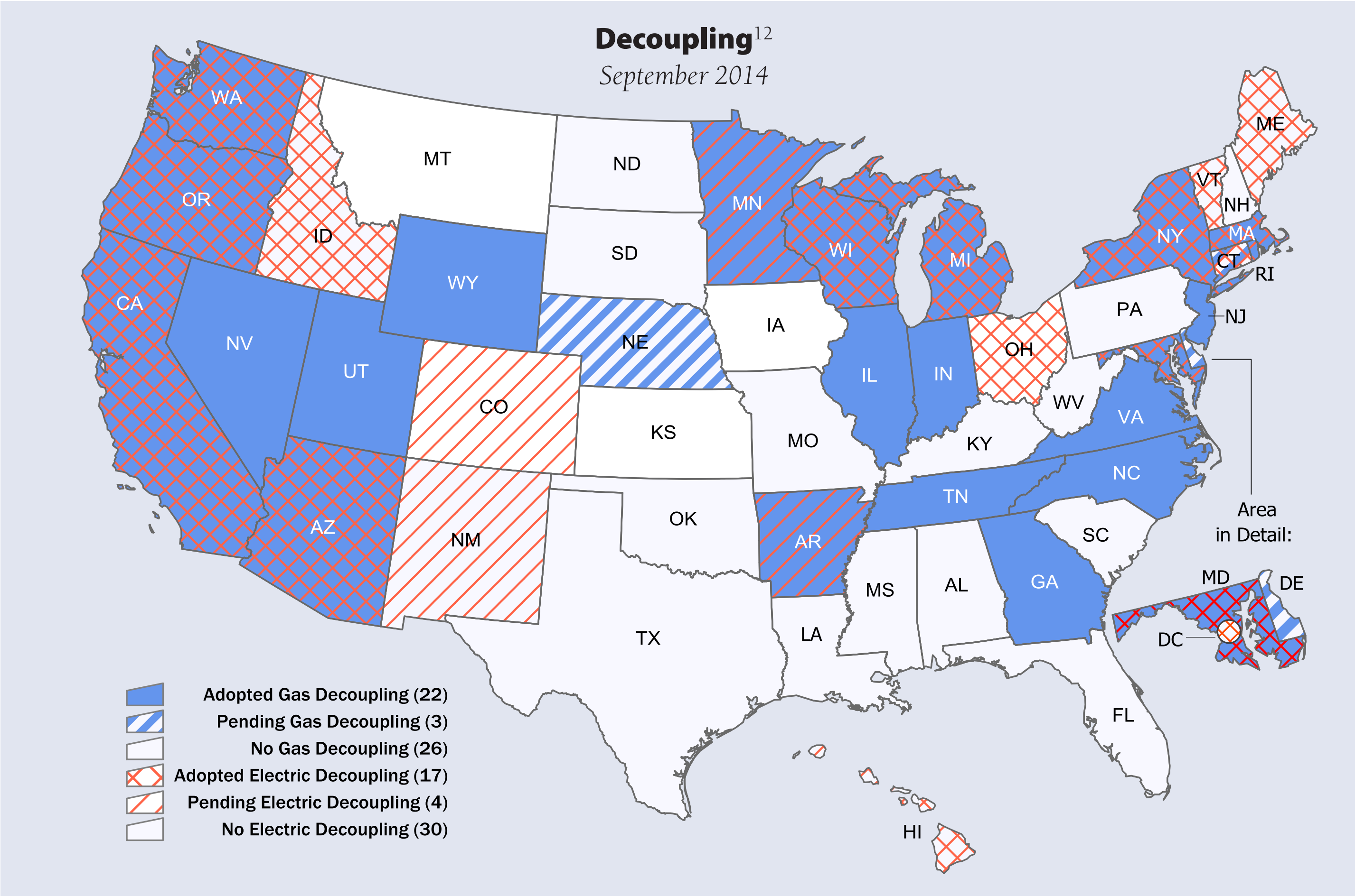
Demand Charges

Some utilities have proposed implementing demand charges on residential and small commercial consumers to recover a portion of revenues based on the customer's highest hourly usage during a month. These types of rate designs are common for large commercial consumers. These are less appropriate for small users, because a customer's highest hourly usage may be a poor predictor of their monthly or annual usage, or of the demand they place on the grid during peak hours and therefore the costs incurred to serve them. For example, an apartment dweller may have an electric water heater, coffee pot, hair dryer, and range all operating for a short period in the morning, creating a short-duration peak demand of 10 kilowatts, when their average consumption is less than 1

10 Presentation of W. Shirley, Arizona Corporation Commission, April 15, 2010.

11 See, for example, *Performance-Based Regulation for EU Distribution Utilities.* (2014). Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/7332

Figure D-3



kilowatt. The utility gets the benefit of all of the units in that apartment building having diversity in their loads — meaning that all of the appliances are not running at the same time throughout the building.

Because apartments typically have lower demands than single-family homes, this rate form is less hostile to small users than a high fixed charge. But demand charges normally bill each customer based on their individual demand, not on their contribution at the time of the system peak, the circuit peak, the class peak, or even the peak of the customers sharing the same line transformer. In this way, they are inefficient rate forms. (See discussion of residential demand charges in Chapter IV.)

The only distribution system component that is sized to individual customer demands is the final line transformer; therefore, the only cost that can be justified to be included in a demand charge based on individual customer peaks is that of the transformer. The remainder of the system is sized based on the combined coincident demand of many customers on the circuit or the entire grid during extreme periods. While a demand charge based on the contribution of each customer to the system coincident peak demand would be one way to recover these costs, it would be poorly understood and could create highly volatile bills. A time-varying energy charge is a more easily understood way to achieve the same goal.

Connected Load Charges

Several utilities impose separate monthly fixed charges on customers of different size, often measured by the size of the electrical panel being served. This provides utilities with a stable amount of revenue each month to cover the cost of the grid connection, and also imposes higher charges on customers with larger potential usage. If the connected load charge is limited to the costs that are sized to individual customers — the line transformer and service

12 Source: Natural Resources Defense Council, http://www.nrdc.org/energy/decoupling/.

Table D-5

Manitoba Hydro Residential Electric Rate		
Standard Residential Tariff No. 2014-01		
Monthly Basic Charge:	NOT Exceeding 200 Amp	$7.28
	Exceeding 200 Amp	$14.56
Plus **Energy Charge:**		7.381c/kWh
Note: Minimum monthly bill is the basic charge		

drop — then it meets the first rate design criteria, that a customer should be able to connect to the grid for no more than the cost of connecting to the grid.

An example of this type of charge is the residential rate design of Manitoba Hydro in Canada. Their rate design is intended to capture customers with electric heat, who impose much higher capacity costs on the distribution transformers that serve them. Table D-5 shows the Manitoba Hydro rate.

Summary

This appendix has addressed the concept of high monthly fixed charges to recover electric utility distribution costs. This is a hotly contested rate design issue, and it is inevitable that different regulatory bodies will reach different conclusions. The key principles that we have sought to detail are:

- Customers should be able to connect to the grid for no more than the cost of connecting to the grid: Only very local distribution costs, such as the final line transformer and service drop, are "fixed costs" of individual customers connecting to the grid.
- Competitive industries do not impose fixed charges on customers, but instead bundle all costs into a per-unit cost; since one purpose of regulation is to impose on monopoly utilities the pricing discipline that the market imposes on competitive businesses, regulators should seek to minimize fixed charges in electricity tariffs.
- Other types of fixed charges, such as residential demand charges, are generally inappropriate, and should give way to time-differentiated energy charges.

Exhibit EDH-3

Strauss, B., C. Tebaldi, S. Kulp, S. Cutter, C. Emrich, D. Rizza, and D. Yawitz (2016). Pennsylvania and the Surging Sea: A vulnerability assessment with projections for sea level rise and coastal flood risk. Climate Central Research Report.

CLIMATE CENTRAL

PENNSYLVANIA AND THE SURGING SEA

A vulnerability assessment with projections for sea level rise and coastal flood risk

This page intentionally blank

CLIMATE CENTRAL

PENNSYLVANIA AND THE SURGING SEA

A VULNERABILITY ASSESSMENT WITH PROJECTIONS FOR SEA LEVEL RISE AND COASTAL FLOOD RISK

ABOUT CLIMATE CENTRAL

Climate Central surveys and conducts scientific research on climate change and informs the public of key findings. Our scientists publish and our journalists report on climate science, energy, sea level rise, wildfires, drought, and related topics. Climate Central is not an advocacy organization. We do not lobby, and we do not support any specific legislation, policy or bill. Climate Central is a qualified 501(c)3 tax-exempt organization.

Climate Central scientists publish peer-reviewed research on climate science; energy; impacts such as sea level rise; climate attribution and more. Our work is not confined to scientific journals. We investigate and synthesize weather and climate data and science to equip local communities and media with the tools they need.

July 2016

Princeton: One Palmer Square, Suite 330 Princeton, NJ 08542
Phone: +1 609 924-3800
Toll Free: +1 877 4-CLI-SCI / +1 (877 425-4724)
www.climatecentral.org

Cover image courtesy of Wikimedia Commons

REPORT AUTHORS

BEN STRAUSS, PhD, Lead

Vice President for Sea Level Rise and Climate Impacts, Climate Central

Dr. Strauss is the Vice President for Sea Level Rise and Climate Impacts at Climate Central. He has published multiple scientific papers on sea level rise, testified before the U.S. Senate, and led development of the SurgingSeas.org coastal flood risk tool, leading to front-page coverage in the New York Times and Washington Post, appearances on NBC, ABC, CBS, PBS and NPR national programming. He holds a Ph.D. in Ecology and Evolutionary Biology from Princeton University, an M.S. in Zoology from the University of Washington, and a B.A. in Biology from Yale University.

CLAUDIA TEBALDI, PhD

Project Scientist, National Center for Atmospheric Research and Science Fellow, Climate Central

Dr. Tebaldi is a climate statistician at the National Center for Atmospheric Research and collaborates with the Climate Science and Impacts groups at Climate Central. Her research interests include the analysis of observations and climate model output in order to characterize observed and projected climatic changes and their uncertainties. She has published papers on detection and attribution of these changes, on extreme value analysis, future projections at regional levels, and impacts of climate change on agriculture and human health and she is currently a lead author for the IPCC Assessment Report, within Working Group 1. She has a Ph.D. in statistics from Duke University.

SCOTT KULP, PhD

Computational Scientist and Senior Developer, Climate Central

Dr. Scott Kulp serves as Computational Scientist and Senior Developer for Climate Central's Program on Sea Level Rise, where his research interests include the impacts of sea level rise on coastal communities. He is also focused on the development of Climate Central's Surging Seas 2.0 Analysis System and Risk Finder web toolkit. Scott holds a Ph.D. in Computer Science from Rutgers University for his work on the topic of cardiac blood flow simulations. Previously, Dr. Kulp has worked for the U.S. Department of Defense on several research projects, such as the simulation of iris tissue deformation and GPU-accelerated neural networks.

CONTRIBUTORS

SUSAN CUTTER, PhD

Hazards and Vulnerability Research Institute, University of South Carolina

CHRIS EMRICH, PhD

Hazards and Vulnerability Research Institute, University of South Carolina

DANIEL RIZZA

Climate Central

DANIEL YAWITZ

Climate Central

ACKNOWLEDGEMENTS

To NOAA's Office for Coastal Management, which has provided high-accuracy coastal elevation data, consistent courtesy, and leadership with its Digital Coast Sea Level Rise Viewer and Coastal Flood Exposure Mapper, enterprises this research strives to extend.

To officials at the Environmental Protection Agency (EPA), the Federal Communications Commission (FCC), and other agencies, who provided special guidance regarding their extensive public geospatial datasets.

To Climate Central's financial supporters for this project: The Kresge Foundation, The Rockefeller Foundation, The Schmidt Family Foundation, and Island Foundation.

And finally to all of our present and past colleagues at Climate Central not listed as authors or contributors, but who have provided support on this project in small ways and large, with particular thanks to Remik Ziemlinski, and also Paul Ferlita, Lindsay Harmon, and Alyson Kenward.

SUGGESTED CITATION

Strauss, B., C. Tebaldi, S. Kulp, S. Cutter, C. Emrich, D. Rizza, and D. Yawitz (2016). Pennsylvania and the Surging Sea: A vulnerability assessment with projections for sea level rise and coastal flood risk. Climate Central Research Report. pp 1-30.

CONTENTS

CONTENTS

EXECUTIVE SUMMARY

In records running back to 1900, Philadelphia has never seen waterfront flooding that reaches 4 feet above the local high tide line. But under a mid-range sea level rise scenario, floods within the Delaware Estuary exceeding 4 feet are more likely than not to take place by 2040, less than one 30-year mortgage cycle away. Under a low-range scenario, chances are just below even; and under a high-range scenario, they reach 3 in 4. At the other end of the spectrum, under high-range projections, there is roughly a 4 in 5 chance of floods above 9 feet by the end of the century.

Nearly 9 square miles of land lie less than 4 feet above the high tide line in Pennsylvania. Some $686 million in property value, and more than 5,000 people residing in more than 2,000 homes – mostly in Philadelphia – sit on this area. More than $250 million of the property sits within just one zip code, 19153 (Philadelphia International Airport). Totals jump to some $3.4 billion, more than 27,000 people, and more than 12,000 homes on more than 29 square miles of land under 9 feet.

The state has 63 miles of road below 4 feet, plus 23 hazardous waste sites, 15 wastewater sites, and 4 power plants. At 9 feet, these numbers grow to nearly 227 miles of road, 114 hazardous waste sites, 37 wastewater sites, and 10 power plants, as well as 2 museums.

Sea levels are rising at an accelerating rate, and the scientific community is confident that global warming is the most important cause. Higher sea levels translate to more and higher coastal floods. To forecast future risk, this analysis integrates historic local sea level trends and flood statistics with global sea level rise scenarios, developed by a multi-agency federal task force led by NOAA in support of the recent U.S. National Climate Assessment.

This report is being released as a high-level summary of findings and methods, coincident with the online launch of a Surging Seas Risk Finder tool for the state, providing much more detailed and localized findings, and accessible via http://riskfinder.org. The tool includes:

- Interactive local projections of sea level rise and increasing coastal flood risk from 1-10 feet by decade;
- A zooming, zip-searchable map of low-lying areas threatened, plus layers showing social vulnerability, population density and property value;
- Detailed assessments of populations, property, infrastructure and contamination sources exposed, for each implicated county, city, town, zip code, planning district, legislative district and more;
- State- and county-wide heat maps facilitating high-level vulnerability comparisons; and
- Customizable fact sheets and brief reports that integrate key findings from across all analyses for each locality, and provide interpretation and context.

Detailed knowledge of vulnerability is a critial tool for communities seeking to build resiliency to the climate challenges of today and the future.

01. INTRODUCTION

IN BRIEF

In March 2012, Climate Central released its first analysis of sea level rise and coastal flood threats in the United States. We published two scientific papers in a peer-reviewed journal; a national report; fact sheets for each coastal state; and an interactive online map called Surging Seas. About 800 stories in local to national media covered our findings, and a U.S. Senate committee invited Climate Central to testify about the research in April 2012 – six months before Hurricane Sandy.

This report represents a major extension to our analysis for Pennsylvania, using the same essential methods as our original work, but incorporating greatly improved and expanded data. The report summarizes major themes and findings taken from a much larger body of results accessible via a new interactive online tool, the Surging Seas Risk Finder, available for a growing set of coastal states throughout the U.S.

RESEARCH IMPROVEMENTS

Our 2012 analysis used the best available national coverage elevation dataset at the time. This analysis uses far more accurate laser-based (lidar) elevation data. Our 2012 research assessed land, population and housing vulnerable to sea level rise and coastal flooding. This research assesses over 100 additional variables, including socially vulnerable populations, populations by racial and ethnic group, property value, roads, rail, airports, power plants, sewage plants, hazardous waste sites, schools, churches, and hospitals. Our 2012 analysis tabulated exposure at state, county, and city levels. This analysis adds zip codes, congressional districts, planning districts, state and local legislative districts, and more.

For sea level rise projections, this report relies primarily upon scenarios produced by a multiagency task force for the U.S. National Climate Assessment (Parris et al 2012), locally adapted to Pennsylvania. However, the full analysis and Risk Finder also include many other global sea level rise models and projections -- also locally adapted – not included in our 2012 analysis. We localize by factoring in local effects, such as sinking land, employing the same methods as in our original peer-reviewed research.

We also carry forward the same methods we previously used to characterize storm surge risk, and integrate it with projected sea levels, to develop projections of overall local flood risk by decade. However, we have updated analysis inputs to include the full available record of hourly water levels at each water level station through the end of 2012. This means decades more data for most stations than the standard 30-year period used in the original analysis, increasing the robustness of our findings.

01. INTRODUCTION

SURGING SEAS RISK FINDER: A NEW ONLINE TOOL

Climate Central built Surging Seas Risk Finder as a public web tool to help communities, planners, and leaders better understand sea level rise and coastal flood risks.

The Surging Seas Risk Finder web tool provides:

- interactive submergence risk maps that use a bathtub model to show areas vulnerable to flooding from combined sea level rise, storm surge, and tides, or to permanent submergence by long-term sea level rise, include layers for social vulnerability, population, ethnicity, income, and property value, and are based primarily on LiDAR elevation data supplied by NOAA
- user-selected localized sea level rise and flood risk projections for each decade through the year 2100 based on dozens of selectable sea level rise models and emissions scenarios, including those by NOAA, Army Corps of Engineers, and IPCC
- exposure analysis that covers over 100 demographic, economic, infrastructure and environmental variables using data drawn mainly from federal sources, including the Census, DOE, DOI, EPA, FCC, FEMA, NOAA, and USGS
- community comparisons that tabulate exposure for various area types including zip codes, municipalities, counties, planning districts, agency districts, states, and other administrative units, from local to state to federal levels
- customizable fact sheets and brief reports for every city, county, and other area analyzed in the tool
- map, figure, and data downloads from state to local levels, including counties, cities, towns, zip codes and other jurisdictions (.png, .xls and text formats)

Surging Seas is based on peer-reviewed science and is listed as a resource on the following national portals: NOAA Digital Coast, US Climate Resilience Toolkit, and the White House Climate Data Initiative.

02. A TIMELINE OF GROWING RISKS

Long before sea level rise permanently submerges new land, it will make its presence felt through higher and more frequent coastal floods, because higher seas raise the launch pad for storm surge.

In fact, every coastal flood today is already wider, deeper and more damaging because of the roughly 8 inches (IPCC 2013) of warming-driven global sea level rise that has taken place since 1900. This analysis finds that an intermediate high sea level rise scenario leads to better than even chances of an extreme flood exceeding 4 feet above the high tide line by 2040 in the greater Philadelphia area. Under a high-range sea level scenario, the chances of a flood exceeding the same level in the same time frame increase to 3 in 4.

This section explores projected sea level rise and how it aggravates coastal flooding.

SEA LEVEL RISE PROJECTIONS

Using scenarios from a NOAA-led technical report to the National Climate Assessment (Parris et al 2012), this analysis makes mid-range or "intermediate high" local sea level rise projections for Pennsylvania of roughly 1.6 feet by mid-century, and 4.5 feet by 2100. These figures all use sea level in 1992 as the baseline.

GLOBAL SEA LEVEL RISE PROJECTIONS

The Earth's average temperature has warmed by more than one degree Fahrenheit over the last century, and scientists overwhelmingly agree that most or all of this warming comes from human influence (IPCC 2013). This influence comes mainly through the burning of fossil fuels and resulting accumulation of carbon dioxide in the atmosphere.

Global sea level rise is one of the scientifically best-established consequences of this warming. Warming shrinks glaciers and ice sheets, adding water to the ocean; and also heats up the ocean, expanding it. Over the past two decades, global sea level has risen roughly twice as fast as it did during the 20th century.

Projecting future sea level is a difficult scientific challenge, not least because it will depend upon how much more carbon humans put into the atmosphere. For global sea level rise projections, this analysis relies on scenarios developed by the National Oceanic and Atmospheric Administration (NOAA) and collaborating agencies for the U.S. National Climate Assessment (Parris et al 2012). We focus on the intermediate low, intermediate high, and highest sea level rise scenarios, which point to 1.6 ft, 3.9 ft, or 6.6 ft of sea level rise globally by 2100, from a 1992 starting point. For simplicity, we call these scenarios "slow", "medium" and "fast."

We omit the NOAA lowest scenario in this report. This scenario projects this century's average rate of sea level rise as the same as last century's, lower than the average rate from the last two decades. Such an outcome seems very unlikely given projections for warming this century, and the strong observed relationship between global temperature and sea level change over the last century (Vermeer and Rahmstorf 2009).

02. A TIMELINE OF GROWING RISKS

The Intergovernmental Panel on Climate Change recently released its Fifth Assessment Report on climate science (IPCC 2013). IPCC's sea level projections range from 0.9-3.2 feet by 2100, but explicitly do not include a potential rapid ice sheet breakdown scenario. NOAA's highest projection is intended to capture such a possibility, and thus the highest plausible sea level rise for the century, as an indicator of maximum risk for planning purposes.

Research published since these projections were made indicates that the West Antarctic Ice Sheet has begun an unstoppable collapse that will likely lead to 10-plus feet of rise over centuries (Joughin et al 2014, Rignot et al 2014). Further research indicates that Antarctic ice loss rate has recently doubled, albeit over a short measurement period (McMillan et al 2014); that Antarctica contributed more than 6 feet of sea level rise per century during a geologically recent warming episode (Weber et al 2014); and that it could contribute 3 feet or more this century (DeConto and Pollard 2016).

Surging Seas Risk Finder, the interactive web tool accompanying this report, includes projections based on scenarios developed by NOAA for the National Climate Assessment; IPCC projections; U.S. Army Corps of Engineers guidelines, semi-empirical projections developed by Vermeer and Rahmstorf (2009); and a no-global-warming scenario for comparison. We will add additional global sea level rise projections over time.

Local Sea Level Rise Projections

Local sea level rise can differ from global sea level rise for many reasons. The ocean is not flat, and shifting currents and sea surface temperatures can alter local sea level trends over years or decades. In addition, the land itself is slowly sinking or (more rarely) rising in many coastal areas, augmenting or diminishing local sea level rise. Later in the century, gravity effects will also play a role: as ice sheets diminish, so will the gravitational force they exert on the oceans, and ocean surface water will make subtle adjustments accordingly.

For its main projections, this analysis uses locally adapted scenarios from NOAA's report to the National Climate Assessment (Parris et al 2012). For estimates based on global projections from other studies, this analysis employs the same method as Tebaldi et al (2012) to develop projections for each location studied. In essence, we compare global sea level rise to local sea level rise measured at a water level station over a 50-year period. We use the difference to define a local component of sea level rise, and assume that the local component rate will continue unchanged into the future. This is a reasonable assumption at least for the effects of sinking or rising land, effects important enough to account for most or all of the long-term local component in most places (Tebaldi et al 2012). (See Appendix A or Tebaldi et al (2012) for more detail.)

For this report and as presented by the Surging Seas Risk Finder, we developed projections at the closest long-term NOAA water level station to Pennsylvania, at Reedy Point, DE, 39 miles from Philadelphia. We did not use the current station at Philadelphia because of its insufficiently long record of hourly water levels, needed for our full analysis.

02. A TIMELINE OF GROWING RISKS

The projections given in this analysis should be taken as indicative of long-term trends, and not as precise projections for specific years. Global and local sea level experience natural ups and downs over years and decades that may temporarily obscure the underlying trend, but which will balance out over time.

COASTAL FLOODING: HISTORY AND PROJECTIONS

Rising seas raise the launch pad for storm surge, driving coastal floods higher. This study projects future flood risk by superimposing sea level rise projections onto historical patterns of flooding. In other words, we assume that coastal storm statistics remain constant – the same frequency and intensity of coastal storms – while sea levels rise. If storms instead worsen, then this analysis would underestimate flood risk.

Historical Analysis to Define Extreme Floods

The first step in this approach is to characterize historical coastal flood risk at each study site – in this case, at Reedy Point, DE, which is 39 miles from Philadelphia, downstream but still within the Delaware Estuary, like Philadelphia. We apply standard methods to estimate the precise relationship between a flood's height and its annual likelihood (the higher the rarer), based on a long historical record of hourly water levels. For example, we estimate that a flood with a 1% annual chance – what we call an "extreme" flood in this study, and commonly referred to as a "100-year" flood – reaches 4.1 feet above the high tide line at Reedy Point, DE. In more than a half-century of records at Reedy Point, the all-time observed highs did not exceed 3.4 feet, but the all-time record high measured at Philadelphia since 1900 is 3.9 feet during Superstorm Sandy in 2012. This contrast suggests that our analysis may bias risks low for Philadelphia and Pennsylvania, as it employs extreme water level statistics using the record from Reedy Point, which may experience a milder regime than Philadelphia, as suggested by the long-term highs.

We apply the same methods as Tebaldi et al (2012) for this analysis (see Appendix A for a briefer summary). However, we update our previous findings by now including water level records through the end of 2015, and back to the earliest year with reliable records at each water level station. This allows us to better project future risks of "unprecedented" floods as well as statistically "extreme" ones.

In this report, we give all flood heights and water levels in elevations relative to Mean Higher High Water (MHHW), or what we more simply call today's "high tide line," defined based on tide levels during NOAA's standard 1983-2001 tidal "epoch." Our purpose is to give a good sense of how high floods might reach above normal local high water lines. Note that different sources use different reference frames; tidesandcurrents.noaa.gov (more specifically here) provides data for inter-conversions at most stations, for example to and from Mean Lower Low Water (MLLW) and standard modern map elevation (North American Vertical Datum 1988, or NAVD88).

02. A TIMELINE OF GROWING RISKS

Coastal Flood Projections

As sea levels rise, they increase the chances of extreme floods by today's standards. For example, an extreme flood reaching 4.1 feet above the present high tide line at Reedy Point, DE, would today require a 1%-annual-chance combination of storm surge and tide. But after 1.5 ft of sea level rise, a flood reaching the same absolute elevation would only require a 1.5-foot lesser combination of storm and tide, coming with a roughly 10% annual chance. This transition from rarity to fairly common event would take place in under 50 years in a mid-range or "medium" sea level rise scenario.

We assessed when floods would exceed standard water levels from 1-10 ft above the high tide line, computing probabilities for each level by decade, based on NOAA's intermediate high scenario ("medium" rise, here), at Reedy Point, DE.

For example, floods reaching more than 4 feet MHHW essentially become a certainty by end-of-century under NOAA's intermediate low ("slow") sea level rise scenario. The intermediate high (or medium) scenario shifts this outcome two decades sooner.

Floods reaching more than 9 feet MHHW have roughly a 4 in 5 chance of occurring by end-of-century under NOAA's high ("fast") sea level rise projections, but the chances of floods exceeding 10 feet by the same end date are 1 in 4.

Therefore, 4-to-9 feet can be viewed as a reasonable range where extreme floods are likely this century along the whole Pennsylvania coast, depending upon sea level rise scenario. Much higher floods are also possible but with lower probability.

The Surging Seas Risk Finder presents complete results for all levels and locations.

It is important to note that while sea level rise projections are fairly similar for most neighboring water level stations, local flood risk profiles tend to vary more substantially. In general, flood risk by elevation can vary significantly across short distances, depending upon local geography. Thus the escalating flood risks computed for any station may be taken as indicative of increasing risk in its wider area, but should not be interpreted as providing predictions for nearby areas. In the case of this study and the difference between Reedy Point and Philadelphia, historic high water levels suggest that Philadelphia experiences higher flooding relative to its local high tide line, so the fact that this study relies on statistics from Reedy Point may bias our results low for risks for Philadelphia and Pennsylvania.

02. A TIMELINE OF GROWING RISKS

Global warming multiplies extreme flood risk

Since sea level rise multiplies extreme coastal flood risk, and global warming contributes to sea level rise, global warming multiplies flood risk. This effect is independent of any potential warming influence on storm frequency or intensity. We assessed the sea level driven global warming multiplier by comparing flood probabilities with and without the global component of sea level rise (leaving out local components that might come from sinking or rising land).

We found that global warming has already increased the annual likelihood of extreme 4 ft floods at Reedy Point, DE by about 50 percent.

Multipliers for cumulative flood probabilities behave more complexly, because the cumulative risk for an extreme flood becomes substantial when accumulated across many decades, even in the absence of global sea level rise. This puts a cap on multiplier values: for example, a background 50% cumulative risk cannot have a multiplier any greater than 2X.

03. PEOPLE, PROPERTY AND INFRASTRUCTURE IN HARM'S WAY

Nearly 9 square miles of land lie less than 4 feet above the high tide line in Pennsylvania. Some $686 million in property value, and more than 5,000 people residing in more than 2,000 homes – mostly in Philadelphia – sit on this area. More than $250 million of the property sits within just one zip code, 19153 (Philadelphia International Airport). Totals jump to some $3.4 billion, more than 27,000 people, and more than 12,000 homes on more than 29 square miles of land under 9 feet.

The state has 63 miles of road below 4 feet, plus 23 hazardous waste sites, 15 wastewater sites, and 4 power plants. At 9 feet, these numbers grow to nearly 227 miles of road, 114 hazardous waste sites, 37 wastewater sites, and 10 power plants, as well as 2 museums.

LAND

Pennsylvania has nearly 9 square miles of land at less than 4 feet MHHW, increasing to nearly 29 square miles less than 9 ft above the tide line, after accounting for potential protection from levees and other features. Bucks and Philadelphia Counties combine to make over three-quarters of the exposure at both 4 and 9 feet.

These values are based on analysis of high-resolution land and tidal elevation data from NOAA, after screening out areas classified as saltwater wetlands by the U.S. Fish and Wildlife Service (see Appendix A for more detailed methodology).

We further analyzed how much low-lying land might be protected by levees or other flood control structures (as represented in FEMA's Midterm Levee Inventory), or natural features such as ridges (as represented in the elevation data): 47 percent of the total exposed area at 4 feet, and 11 percent at 9 feet. In Philadelphia, our analysis shows 25 percent of exposed land at 4 feet is protected – 2 percent at 9 feet. Protection, or isolation, is an important factor in Pennsylvania; all figures given in this report take it into account.

Our approach does not take into account, and also avoids complications from, future erosion or the migration of marshes as sea levels rise. It also does not address the uneven surfaces of floodwaters driven by individual storms, and influenced by details of local geography.

Overall, the maps and analyses here should not be taken as precise predictions or flood emergency guides. Rather, we present them as risk indicators in a world of rising sea levels and increasing floods.

03. PEOPLE, PROPERTY AND INFRASTRUCTURE IN HARM'S WAY

PEOPLE, PROPERTY AND INFRASTRUCTURE

Once maps of vulnerable land are established, it is relatively straightforward to account for the populations, property and infrastructure exposed within these zones. The Surging Seas Risk Finder presents hundreds of thousands of combinations of analysis results by geography, water level, and variable. Here we present some of the major categories and highlights, with a focus on exposure below 4 and 9 feet, excluding areas that levees and other barriers appear to protect.

Nearly 9 square miles of land lie less than 4 feet above the high tide line in Pennsylvania. Some $686 million in property value, and more than 5,000 people residing in more than 2,000 homes – mostly in Philadelphia – sit on this area. More than $250 million of the property sits within just one zip code, 19153 (Philadelphia International Airport). Totals jump to some $3.4 billion, more than 27,000 people, and more than 12,000 homes on more than 29 square miles of land under 9 feet.

The state has 63 miles of road below 4 feet, plus 23 hazardous waste sites, 15 wastewater sites, and 4 power plants. At 9 feet, these numbers grow to nearly 227 miles of road, 114 hazardous waste sites, 37 wastewater sites, and 10 power plants, as well as 2 museums. Surging Seas Risk Finder presents results for many more infrastructure and facility categories, as well as population groups and potential contamination sources.

The Philadelphia International Airport appears to be protected at water levels up to 4 feet above the local high tide line, but not at higher levels.

This analysis simplifies most facilities as points with a single latitude and longitude. It also evaluates exposure by evaluating the height of the land that structures sit upon. It takes into account neither the full footprint of a facility; nor the potential elevation of structures or equipment above ground; nor the possibility of unsealed basement areas. We regard such analysis as useful for assessing the general exposure of different facility types across different geographies, and as useful for screening the possible exposure of individual facilities. However, authoritative assessments for individual facilities are best served by on-the-ground measurement.

THE MOST VULNERABLE

Social vulnerability is a broad term that describes the sensitivity of populations to the impacts of environmental risks and hazards, including coastal flooding. Social vulnerability helps explain why some places can experience hazards differently even without differences in exposure. The Social Vulnerability Index is a tool that synthesizes socioeconomic characteristics of populations – characteristics known to influence a community's ability to prepare for, respond to, and recover from hazard events like floods (see e.g. Emrich and Cutter 2011; Finch et al 2010; Cutter et al. 2013).

Our analysis found nearly 1,300 people in the high Social Vulnerability Index class below 4 feet across Pennsylvania. The total jumps to more than 9,700 below 9 feet.

The Social Vulnerability Index compares places based on their relative levels of social vulnerability. For this analysis, vulnerability was assessed at the Census tract level, using 27 variables from the 2010 Census and the 2006-10 American Community Surveys (see Appendix A for further methodological details). The online Submergence Risk Map that accompanies this report includes a feature visualizing social vulnerability levels in areas that are physically vulnerable to coastal flooding and sea level rise.

The Social Vulnerability Index shows where there is uneven capacity for preparedness and response and where pre and post-event resources might be most effectively used to reduce pre-existing vulnerability and increase resilience post-disaster. The index is also a useful indicator in understanding spatial differences in disaster recovery. It has been used in combination with other disaster data to provide emergency responders with a much clearer understanding of disaster impacts, thus providing decision makers with an objective comparison of damages sustained across the full spectrum of affected communities (see http://webra.cas.sc.edu/hvri/products/SoVIapplications.aspx).

04. CONCLUSION

Long before rising seas redraw local maps, they will result in more coastal floods reaching higher. They are already having this effect.

The research in this report underscores the high concentration and wide range of populations, property, infrastructure, buildings, and potential contamination sources in low-lying coastal areas. Patterns vary from place to place.

It will not require major storms to cause extensive economic damage and suffering in the future. Knowledge of vulnerabilities can lead to better preparation for the next inevitable flood, and the ones after. Higher floods in the future are certain, but how much damage they inflict is not – and will depend on the measures coastal communities take.

05. REFERENCES

American Society of Civil Engineers (2013). 2013 Report Card for America's Infrastructure: Levees. http://www.infrastructurereportcard.org/a/documents/Levees.pdf accessed October 2013.

Cutter, S. L., C. T. Emrich, D. P. Morath, and C. M. Dunning (2013). Integrating social vulnerability into federal flood risk management planning, J. Flood Risk Management DOI: 10.1111/jfr3.12018.

DeConto, R. M., and Pollard, D. (2016). Contribution of Antarctica to past and future sea-level rise. Nature, 531(7596), 591-597.

Emrich, C. T., & Cutter, S. L. (2011). Social vulnerability to climate-sensitive hazards in the southern United States. Weather, Climate, and Society, 3(3), 193-208.

Finch, C., Emrich, C. T., & Cutter, S. L. (2010). Disaster disparities and differential recovery in New Orleans. Population and Environment, 31(4), 179-202.

Grinsted, A., Moore, J. C., & Jevrejeva, S. (2012). Homogeneous record of Atlantic hurricane surge threat since 1923. Proceedings of the National Academy of Sciences, 109(48), 19601-19605.

Ingebritsen, S. E., Ikehara, M. E., Galloway, D. L. & Jones, D. R. (2000). Delta Subsidence in California: The sinking heart of the State. U.S. Geological Survey Fact Sheet FS-005-00.

Intergovernmental Panel on Climate Change Working Group 1 (2013). Summary for Policy Makers.

Joughin, I., Smith, B. E., & Medley, B. (2014). Marine Ice Sheet Collapse Potentially Under Way for the Thwaites Glacier Basin, West Antarctica.Science, 344(6185), 735-738.

Kopp, R. E., Horton, R. M., Little, C. M., Mitrovica, J. X., Oppenheimer, M., Rasmussen, D. J., Strauss, B. H. and Tebaldi, C. (2014). Probabilistic 21st and 22nd century sea-level projections at a global network of tide-gauge sites. Earth's Future, 2(8), 383-406.

McMillan, M., Shepherd, A., Sundal, A., Briggs, K., Muir, A., Ridout, A., ... & Wingham, D. (2014). Increased ice losses from Antarctica detected by CryoSat-2. Geophysical Research Letters

Moss, R.H., Edmonds, J.A., Hibbard, K.A., Manning, M.R., Rose, S.K., van Vuuren, D.P., Carter, T.R., Emori, S., Kainuma, M., Kram, T., Meehl, G.A., Mitchell, J.F.B., Nakicenovic, N., Riahi, K., Smith, S.J., Stouffer, R.J., Thomson, A.M., Weyant, J.P. and Wilbanks, T.J. (2010). The next generation of scenarios for climate change research and assessment. Nature, 463(7282): 747-756.

National Research Council (1987). Responding to Changes in Sea Level: Engineering Implications. National Academy Press: Washington, D.C. http://www.nap.edu/catalog.php?record_id=1006
National Research Council (2012). Sea-Level Rise for the Coasts of California, Oregon and Washington: Past, Present and Futre. National Academy Press: Washington, D.C. http://www.nap.edu/catalog.php?record_id=13389

05. REFERENCES

Neumann, J., Hudgens, D., Herter, J., & Martinich, J. (2010). The economics of adaptation along developed coastlines. Wiley Interdisciplinary Reviews: Climate Change, 2(1), 89-98.

Parris, A., P. Bromirski, V. Burkett, D. Cayan, M. Culver, J. Hall, R. Horton, K. Knuuti, R. Moss, J. Obeysekera, A. Sallenger, and J. Weiss (2012). Global Sea Level Rise Scenarios for the US National Climate Assessment. NOAA Tech Memo OAR CPO-1. 37 pp.

Rignot, E., Mouginot, J., Morlighem, M., Seroussi, H., & Scheuchl, B. (2014). Widespread, rapid grounding line retreat of Pine Island, Thwaites, Smith, and Kohler glaciers, West Antarctica, from 1992 to 2011. Geophysical Research Letters.

Southeast Florida Regional Climate Change Compact Technical Ad hoc Work Group (2011). A Unified Sea Level Rise Projection for Southeast Florida. A document prepared for the Southeast Florida Regional Climate Change Compact Steering Committee. 27 p.

Strauss, B. H., Ziemlinski, R., Weiss, J. L., & Overpeck, J. T. (2012). Tidally adjusted estimates of topographic vulnerability to sea level rise and flooding for the contiguous United States. Environmental Research Letters, 7(1), 014033.

Tebaldi, C., Strauss, B. H., & Zervas, C. E. (2012). Modelling sea level rise impacts on storm surges along US coasts. Environmental Research Letters,7(1), 014032.

USACE (2011). Sea-Level Change Considerations for Civil Works Programs, Department of the Army Engineering Circular 1165-2-212, October 2011, U.S. Army Corps of Engineers, CECW-CE Washington, DC 20314-1000. 32pp. http://planning.usace.army.mil/toolbox/library/ECs/EC11652212Nov2011.pdf

Vermeer, M., & Rahmstorf, S. (2009). Global sea level linked to global temperature. Proceedings of the National Academy of Sciences, 106(51), 21527-21532.

Weber, M. E., Clark, P. U., Kuhn, G., Timmermann, A., Sprenk, D., Gladstone, R., ... & Ohlwein, C. (2014). Millennial-scale variability in Antarctic ice-sheet discharge during the last deglaciation. Nature.

APPENDIX A: METHODS

PROJECTING LOCAL SEA LEVEL RISE

To localize the various global sea level rise projections used, including the scenarios prepared for the National Climate Assessment (Parris et al 2012), we followed the same essential methods as Tebaldi et al (2012). In that study, we added "semi-empirical" projections of global sea level rise to separate local sea level change components developed for 55 water level stations around the contiguous U.S. Here we use the example of projections built on top of a semi-empirical model, as in Tebaldi et al., to explain the methodology.

For the global component in our semi-empirical approach, we used projections from Vermeer and Rahmstorf (2009). Their approach, based on the recent historic relationship between global sea level and global average temperature, has successfully hind-casted sea level rise over the last century and millennium with great fidelity. The relation estimated over the past observed records of sea level rise and global warming can be applied to projections of future temperature change produced by climate models. By this approach, therefore, future global sea level rise is not directly derived from the output of climate models, but is projected on the basis of the future temperature projections of these models. As projections based on historical observed relationships generally do, this approach assumes that the dynamics captured by the past relation will remain the same for the projected future period. If the ongoing increase in global temperatures leads ice sheets to unravel in ways not experienced during the model's twentieth century calibration period, then this approach may understate the problem.

Use of Vermeer and Rahmstorf's approach allowed this analysis to take into account a wide range of possible futures, from ones where humanity continues to send great amounts of heat-trapping gasses into the atmosphere, to ones where we sharply reduce these emissions. Through Vermeer and Rahmstorf's method we were also able to incorporate a range of possible relationships between emissions and global temperature increases (by using a range of climate model parameters and thus exploring the dimension of model uncertainty), and a range of possible relationships between temperature and sea level (by considering the uncertainty in the parameters of the empirical model). Our analysis rolled all of these factors together to produce one set of best estimates, and a range of potential outcomes around them.

For the current Surging Seas Risk Finder, we updated our semi-empirical projections to employ the most recent carbon emissions scenarios ("Representative Concentration Pathways") and warming models being used by the global scientific community (Moss et al 2010).

In addition to future SLR estimates based on the empirical relation fitted between global temperature projections and SLR, we used global SLR models and scenarios that NOAA prepared for the National Climate Assessment (Parris 2012), and from the IPCC (2013), probabilistic projections based on the IPCC (Kopp et al 2014), and from the U.S. Army Corps of Engineers (2011).

Changes in local sea level come not only from changes in global sea level, but also from local effects such as the slow rising or sinking of coastal land, driven largely by the ancient retreat of massive ice sheets across North America. To determine local effects, we removed global rise from the total

APPENDIX A: METHODS

observed local sea level increase over a 50-year period (1959-2008) at each of the 55 nationwide stations we analyzed in our original study. The difference between the total observed local component and global rise during the same period (both of them expressed as linear trends of sea level change per year) is what we call the local component, and, in our projections, we assumed that each local component will continue as a constant rate into the future that offsets or adds on to the global component as an additive term. A detailed analysis using multiyear data from high-precision continuous GPS stations showed that vertical land motion can explain most or all of these local components. The forces behind such motion generally stay constant for thousands of years.

Our projections should not be interpreted as precise predictions for specific years, but rather best estimates that indicate overall trends, because of all of the factors that could lead to a range of outcomes (for example, different emissions futures) and because of natural year-to-year and decade-to-decade variability. For this reason, we present projections at the decade scale only.

PROJECTING COASTAL FLOOD RISK

In Tebaldi et al (2012) and here, to project the probabilities of reaching different high water levels in the future, through combinations of storms, tides and sea level rise, we developed statistics based on patterns of historical extreme water levels, and then superimposed projected sea level rise onto these. For this report, we used local statistics and local sea level projections for Reedy Point, DE, the station closest to Philadelphia and Pennsylvania.

We used statistical methods specialized for handling extreme values to analyze records of hourly data. We expanded our analysis from the fixed standard 30-year period (1979-2008) used in Tebaldi et al, to use the maximum available high quality data through the end of 2015.

We estimate the parameters of a Generalized Pareto Distribution at each station, characterizing the probability density of extreme water levels at that location, and on the basis of those parameters we derive what is called a "return level curve" for each water level station. Our return level curves relate water heights (in MHHW) to their annual probability: for example, heights with a 1% chance of being reached in any given year ("100-year" or "century" or "extreme" floods) are higher than heights with a 10% chance ("decade floods"), and so forth. We filtered out the effects of ongoing historic sea level rise at each station by estimating a linear trend over the length of the record and subtracting it out, in order to calculate baseline return level curves influenced only by tides, storms, and seasonal shifts in water level.

Once we establish a curve for the baseline period (that we can think of as today in most cases), it is easy to modify it for a given time in the future, on the basis of the effects of sea level rise alone. For example, if at that future time sea level has risen by one foot, an event reaching 5 feet of elevation will have at that future time the same probability of occurring as a minor event reaching 4 feet has today. Thus, sea level rise will make rare high water events of today more likely in the future.

APPENDIX A: METHODS

These considerations allow us to compute the chance that a particular height H will be reached in some future year (say, for example the chance that an event reaching 5 feet will happen in 2030). All that is needed is the amount of sea level rise, say L, between today (the baseline) and that target year, and the return level curve for the baseline: we then take H, subtract L and find, on the curve, the probability associated to the event of size H-L.

Slightly more complex is the computation of the cumulative risk of at least one such event by some future year, i.e., the estimate of the chance that a particular height H will be reached or exceeded by some future year. The way to think of this is as the complement of (i.e., one minus) the probability that such event will never be reached by that year. As an example, let's say the event H is currently a "100-year" event. That means that this year it has 0.01 chances of occurring, and therefore 0.99 chances of not occurring. Next year, if nothing changed, the chance of it not occurring would be the same, therefore the probability of H not occurring this year or next year would be 0.99*0.99=0.98; its complement, that is the chance of H occurring by next year, would be 1-0.98=0.02.

The same calculation applies for any number of years until the target year. We simply multiply the chances of the event H not occurring every year for the entire period, and then take its complement.

Critically, however, sea level rise makes the chance of any event higher –at least on average decade after decade. Therefore we compute changing probabilities over the years, taking into account the effect of sea level rise. To do so, we incorporate local projections of sea level rise decade by decade, not just the total rise projected by the target year.

More specifically, we used the return level curve for each decadal year, e.g. 2040, incorporating sea level rise projected through that year, and applied the same curve for the five preceding and four succeeding years as well. We then used the probability of exceeding H each year between 2011 and the target year to compute the overall odds of exceeding H at least once during the period.

To continue with the example of H as the 100-year event of today one can imagine that for a target year far enough in the future the multiplication will involve values sooner or later (depending on the pace of sea level rise at this station and on the shape of its return level curve) significantly smaller than 0.99, therefore producing a significantly larger value of the complement, by the target year, compared to that computed under the assumption of no sea level rise.

As with our projections of sea level rise, and for similar reasons, we limit our presentation to odds of reaching different flood levels at decade resolution. Any given year, even within a steady long-term trend of sea level rise, may see dips and jumps in the actual value of sea level rise at a given location. Our estimates of sea level rise are appropriate only as long-term average trends, decade after decade.

Note that the same type of calculation performed for a detailed range of values and years in the future allow us to answer a question mirroring the one above. We can search among our results for which size event will become, say, at least Q% likely by the next 20 years, rather than starting with a given size event and ask what its likelihood of occurring at least once in the next 20 year will be. Similarly we can ask questions about waiting times, looking for the number of years it will take for a given size event to occur with at least an Q% chance.

APPENDIX A: METHODS

Our calculations all concern flood levels reaching elevations relative to a stable baseline, the average high tide level during a fixed historic reference period at each station, the so called tidal datum epoch (the current standard epoch is 1983-2001). This way of measuring flood levels is different than pure storm surge, which is calculated as the extra water height above the predicted tidal water level for the very same moment in time. Our focus was not storm surge, but rather how high water actually gets, due to storm surge, plus tide, plus sea level rise.

This analysis assumed that historic storm patterns will not change; in other words, it did not address the possibility that storms might become more or less frequent or severe due to climate change.

This analysis was based on data taken at water level stations. Tides, storm surge, and the resulting statistics vary from place to place, sometimes over short distances, due to factors including land and ocean geometry and storm directions. On the other hand, in our national analysis (Tebaldi et al 2012), results for distantly spaced water level stations within the same region were often similar. Therefore, results from stations may be taken as rough indicators but not precise estimates for their neighborhoods and regions, and the quality and coverage of indication will vary.

ESTIMATING GLOBAL WARMING FLOOD RISK MULTIPLIERS

To estimate how global warming is shifting the odds of high storm surges, through sea level rise, we calculated the odds of extreme events in a hypothetical world with no past or future global sea level rise due to warming, to compare against our original calculations, which included warming. We did this comparison at each water level station in the study. The approach basically translated to subtracting out the roughly 8 inches of historical global sea level rise measured from 1880-2009, and then also assuming no future global sea level rise, for the no-warming scenario at each station (a scenario viewable in the Surging Seas Risk Finder). The no-warming scenarios still included local sea level rise from factors other than warming, such as sinking or lifting land — the full local component of sea level rise.

We made one further adjustment, which was to add back 10% of the historic global sea level rise (10% of 8 inches), in the event that some of the observed historic rise has come from factors other than warming. Research on the sea level budget assigns the great majority of the 8 inches to warming-caused effects: expansion of the ocean as it has warmed, and the melting and calving of glaciers and ice sheets. Small fractions of global sea rise unaccounted for are widely viewed to come at least in part from additional ice loss. We assume 90% of the 8 inches are due to global warming, and thus deduct this amount for our comparison.

For comparison of odds with and without warming, we used standard "100-year" or "century" floods as our reference, meaning water station water levels high enough that they have just a 1% chance of occurring in any given year. We calculated the elevations 100-year floods reach when starting on top of baseline 2012 sea level at each station, using the same data and methods as for our overall water level probability projections. Elevations were relative to average local high tide (MHHW) during a fixed past reference period (the 1983-2001 tidal epoch), as with all elevations in related studies.

APPENDIX A: METHODS

In comparing the probabilities of flood levels with and without global warming, we cut ratios off at ten, because higher ratios start to lose a sense of meaning. We also do not compute ratios at all when the chance of flooding is very close to zero without global warming. These situations create very large ratios whose exact values are meaningless: tiny changes in near-zero odds (odds without global warming) would lead to enormous changes in the ratio value.

This analysis did not address the possibility that storms might become more or less frequent or severe due to climate change. We also limited ourselves to looking at the total effects of global warming, and did not aim to separate fractions caused by humans versus natural variations. The strong scientific consensus points to people as causing most, if not all, of the average warming observed over the last century, and to being the dominant cause of future warming.

MAPPING LOW COASTAL AREAS

To develop our maps of at-risk areas, we used high-resolution, high-accuracy laser-based (lidar) elevation data provided by NOAA. These data have a roughly 5 m (16.5 ft) horizontal resolution. In any small fraction of low-lying areas not covered, we used the highest resolution data available from the National Elevation Dataset (NED), a product of the U.S. Geological Survey.

For general discussion of the accuracy of elevation data and what it means for our maps and statistics, see Strauss et al (2012), which used 1/3 arc-second NED data exclusively, as lidar data were not sufficiently available. This discussion concluded that NED quality data are sufficient for the types of analysis conducted here. Nonetheless, the reported vertical accuracy (root mean square error) of lidar data, as used in this analysis, is roughly ten times more accurate than NED.

We began our process by classifying all cells as ocean (ocean, bay, estuary or saltwater wetland) or land (land or freshwater wetland), because ocean or saltwater marsh misclassified as land would lead to overestimates of susceptible total land area. We admitted cells as land according to a conservative consensus of three independent data sets. First, the cells had to be designated as land within the elevation data itself. Second, we included only cells with centers landward of NOAA's Medium Resolution Digital Vector Shoreline. Finally, we eliminated cells with centers inside areas classified in the National Wetlands Inventory (NWI) as estuarine or marine wetland or deepwater. In computing total land area susceptible, we included NWI freshwater wetlands.

Next, we adjusted the elevation of each cell to be in reference to the nearest average high tide line, instead of a standard zero. For example, if a cell's elevation were five feet, but the local high tide reached three feet, then we would compute an elevation of two feet relative to the tide line. Clearly, sea level rise or a storm surge would need to reach only two feet above high tide to threaten this cell with inundation. Sea level and tidal amplitude vary sometimes widely from place to place, and therefore also the average height of high tide. For local high tide elevations, we used values of Mean Higher High Water from VDatum, a NOAA data product and tidal model.

APPENDIX A: METHODS

Based on these elevations adjusted relative to MHHW, we identified the set of cells beneath each water level threshold from one to ten feet above local high tide, and drew maps of each area.

Finally, we distinguished areas connected to ocean at a given water level, versus isolated areas, to use in different exposure analyses, and for differential display in our online mapping application. We included levees from the Midterm Levee Inventory in this analysis of connectivity, assuming each levee to be of sufficient height and condition to offer protection at every water level. Additional discussion discussion can be found in the main body of this report (see "Land" in Table of Contents).

ASSESSING SOCIAL VULNERABILITY

The Social Vulnerability Index for 2006-10 marks a change in the formulation of the SoVI® metric from earlier versions (see e.g. Emrich and Cutter 2011). New directions in the theory and practice of vulnerability science emphasize the constraints of family structure, language barriers, vehicle availability, medical disabilities, and healthcare access in the preparation for and response to disasters, thus necessitating the inclusion of such factors in SoVI®. Extensive testing of earlier conceptualizations of SoVI®, in addition to the introduction of the U.S. Census Bureau's five-year American Community Survey (ACS) estimates, warrants changes to the SoVI® recipe, resulting in a more robust metric. These changes, pioneered with the ACS-based SoVI® 2005-09, carry over to SoVI® 2006-10, which combines the best data available from both the 2010 U.S. Decennial Census and five-year estimates from the 2006-2010 ACS.

The table on the following page gives a complete list of the 27 variables used in SOVI® 2006-10 for Census tract level analysis.

APPENDIX A: METHODS

Table A1. Variables Used in Social Vulnerability Analysis

VARIABLE	DESCRIPTION
QASIAN	Percent Asian
QBLACK	Percent Black
QHISP	Percent Hispanic
QNATAM	Percent Native American
QAGEDEP	Percent of Population Under 5 Years or 65 and Over
QFAM	Percent of Children Living in Married Couple Families
MEDAGE	Median Age
QSSBEN	Percent of Households Receiving Social Security
QPOVTY	Percent Poverty
QRICH200K	Percent of Households Earning Greater Than $200,000 Annually
PERCAP	Per Capita Income
QESL	Percent Speaking English as a Second Language with Limited English Proficiency
QFEMALE	Percent Female
QFHH	Percent Female Headed Households
QNRRES	Percent of Population Living in Nursing and Skilled-Nursing Facilities
QED12LES	Percent with Less Than 12th Grade Education
QCVLUN	Percent Civilian Unemployment
PPUNIT	People Per Unit
QRENTER	Percent Renters
MDHSEVAL	Median House Value
MDGRENT	Median Gross Rent
QMOHO	Percent Mobile Homes
QEXTRCT	Percent Employment in Extractive Industries
QSERV	Percent Employment in Service Industry
QFEMLBR	Percent Female Participation in Labor Force
QNOAUTO	Percent of Housing Units with No Car
QUNOCCHU	Percent Unoccupied Housing Units

For this analysis, we assessed Social Vulnerability Index scores by Census tract across the entire state. We then assigned tracts high, medium, or low social vulnerability scores, based on whether they fell within the top 20%, middle 60%, or bottom 20%, respectively, of vulnerability for the whole set within each state.

More information on the Social Vulnerability Index is available at http://webra.cas.sc.edu/hvri/products/sovi.aspx

APPENDIX A: METHODS

ESTIMATING EXPOSURE OF PEOPLE, PROPERTY, AND INFRASTRUCTURE

To calculate potential risks at each water level within areas such as zip codes, cities or counties, we used boundaries provided by the 2010 U.S. Census to overlay against our maps of land beneath different water level thresholds. We then computed the amount of land below each threshold in each place. For denominators in percentage calculations, we used our own computations of land area for each place, because our definitions of coastline differed slightly in places from that of the Census.

To tabulate population and housing potentially affected, we used block-level data from the 2010 U.S. Census, and assumed development on dry land only (neither freshwater nor saltwater wetland). For each Census block, we divided the population and number of housing units by the number of dry land cells with centers inside the block. We assigned the resulting per-cell density values back to each cell, creating new datasets for population and housing unit density. To estimate the population or housing at risk for a particular water level, we simply added up population and housing densities of land cells affected under the specification. Our analysis considered the elevation of land upon which housing stands, and made no special provision for elevated or multi-story buildings.

We followed the same approach for property value, computing value density based on Census block group resolution data from Neumann et al (2010). The property value is derived almost exclusively from individual parcel assessed just values, evaluated in 2008, which we adjusted using the Consumer Price Index to 2012 dollars. The data include residential, commercial, industrial, institutional and government property, both taxable and tax-exempt.

For analysis of linear features such as roads and rail, we computed the length of each feature on land below the water level in question, and made totals by feature type (e.g. total roads, federally-owned roads, or mainline rail).

For airports, we used linear runway data, and determined the percentage of runway length on land below each water level. We counted an airport as vulnerable at a given level when this percentage exceeded a threshold of 25%.

For point features, we simply use latitude/longitude coordinates overlaid onto our MHHW elevation map to evaluate whether a building, site or facility falls below a given water level. This approach does not take into account the actual footprint of a structure, nor the possibility that critical features may be elevated above the ground (or stored in an unsealed basement).

The first step in each analysis is to properly filter and de-duplicate records for the feature class or subclass of interest from a source dataset – for example, state-owned roads, commuter rail stations, nuclear power plants, or major hazardous waste sites. We primarily used federal datasets. References for each are accessible via the Surging Seas Risk Finder.

APPENDIX B: GLOSSARY AND ABBREVIATIONS

EPA – U.S. Environmental Protection Agency

Extreme flood – As used in this report, a coastal flood height with a 1% or lower annual chance, assuming the sea level for 2012.

High tide line – see MHHW

IPCC – Intergovernmental Panel on Climate Change

Lidar – Light detection and ranging technology. A method of measuring distance that relies on firing laser beams and analyzing their returned, reflected light.

MHHW – Mean Higher High Water: a local frame of reference for elevation based on the elevation of the higher of the two high tides each day averaged across a reference period. The reference period used is the current tidal epoch, 1983-2001. This report uses "high tide line" as the equivalent of the height of MHHW.

MLLW – Mean Lower Low Water. See MHHW; MLLW is instead a frame of reference based on the elevation of the lower of the two low tides each day.

NCA – National Climate Assessment

NOAA – National Oceanic and Atmospheric Administration

NRC – National Research Council

Sea level rise, slow – In this report, the NRC lower-range sea level rise projection

Sea level rise, medium – In this report, the NRC main sea level rise projection

Sea level rise, fast – In this report, the NRC upper-range sea level rise projection

SLR – Sea level rise

Social vulnerability - A broad term that describes the sensitivity of populations to the impacts of environmental risks and hazards, including coastal flooding; related to a community's ability to prepare for, respond to, and recover from hazard events.

Storm tide – The height of tidal stage plus storm surge

Tidal epoch – Period over which tidal levels are defined. See definition for MHHW.

Princeton: One Palmer Square, Suite 330 Princeton, NJ 08542
Phone: +1 609 924-3800
Toll Free: +1 877 4-CLI-SCI / +1 (877 425-4724)
www.climatecentral.org

Exhibit EDH-4

Petition of the Office of the Massachusetts Attorney General Requesting an Investigation into the impact on the continuing business operations of local gas distribution companies as the Commonwealth achieves its 2050 Climate Limits. (June 4, 2020).

THE COMMONWEALTH OF MASSACHUSETTS
OFFICE OF THE ATTORNEY GENERAL
ONE ASHBURTON PLACE
BOSTON, MASSACHUSETTS 02108

MAURA HEALEY
ATTORNEY GENERAL

(617) 727-2200
(617) 727-4765 TTY
www.mass.gov/ago

June 4, 2020

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Petition of the Office of the Attorney General Requesting an Investigation into the impact on the continuing business operations of local gas distribution companies as the Commonwealth achieves its 2050 Climate Limits.

Dear Secretary Marini:

Enclosed for filing please find the Office of the Attorney General's Petition Requesting an Investigation, as referenced above.

Please do not hesitate to contact me if you have any questions.

Sincerely,

/s/ Jo Ann Bodemer

Jo Ann Bodemer
Assistant Attorney General

Enclosures

cc: Shane Early, Esq., General Counsel, Department of Public Utilities

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Petition of the Office of the Attorney General, pursuant to G.L. c. 12, §§ 11E, 10; and its common law authority to act in the public interest, Requesting an Investigation, pursuant to the Department of Public Utilities' authority under G.L c. 164, §§ 76, 105A into the impact on the continuing business operations of local gas distribution companies as the Commonwealth achieves its target 2050 climate goals.	**D.P.U. 20-XX**

The Office of the Attorney General ("AGO"), pursuant to G.L. c. 164, §§ 76, 105A; G.L. c. 12, §§ 11E, 10; and the AGO's common law authority to act in the public interest, respectfully requests that the Department of Public Utilities (the "Department") initiate an investigation to assess the future of local gas distribution company ("LDC") operations and planning in light of the Commonwealth's legally binding statewide limit of net-zero greenhouse gas ("GHG") emissions by 2050.[1]

As found in the Commonwealth's 2015 update to its Clean Energy and Climate Plan ("CECP") for 2020, the Commonwealth's heating sector must make sizeable reductions in its use

[1] *See* the Global Warming Solutions Act ("GWSA"), St. 2008, c. 298, codified at M.G.L. c. 21N; Executive Office of Energy and Environmental Affairs'("EOEEA") Determination of Statewide Emissions Limit for 2020 (Apr. 22, 2020), *available at* https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit; (setting a legally binding statewide limit of net zero greenhouse gas emissions by 2050, defined as 85 percent below 1990 levels); State of the State Address (Jan. 21, 2021) (Governor commits to achieving net-zero greenhouse gas emissions by 2050), *available at* https://www.mass.gov/news/governor-baker-delivers-2020-state-of-the-commonwealth-address.

of fossil fuels to achieve the state's mandated GHG limit.[2] Ensuring that Massachusetts LDCs' current and planned business and operating practices are consistent with the Commonwealth's 2050 emission reduction mandate and interim targets requires more from the LDCs than "business as usual." Just as declining fossil fuel demand is reshaping markets and business practices in global markets (due to a range of factors including a climate-risk driven transition to clean energy), the Commonwealth's climate policy requirements will have profound impacts on gas distribution system management, operations, and rates. This will require the LDCs to make significant changes to their planning processes and business model. It will also require the Department to develop new policies and structures to protect ratepayers and ensure a safe, reliable, and fair transition away from reliance on natural gas and other fossil fuels.

While policymakers and stakeholders are presently discussing and examining various electric-dependent pathways to achieve the 2050 climate requirements, there has been little

[2] Pursuant to the GWSA, the EOEEA must prepare a CECP every 5 years, beginning in 2010, that sets GHG limits and provides plans to ensure the Commonwealth meets its 2050 mandated emissions limit. See G.L. c. 21N (setting forth standards for targets and plans). Both the 2010 and 2015 update focused on reducing building sector GHG emissions. *See* Massachusetts CECP for 2020, 2015 Update at 19 ("Buildings consume more than 50 percent of the energy used in Massachusetts including the vast majority of the electricity and significant amounts of natural gas and oil primarily for space heating. Emissions from buildings represent over 50 percent of GHGs in 2013, with direct fossil fuel use (*i.e.*, excluding buildings use of electricity) accounting for almost a third of the Massachusetts GHG inventory."), *available at* https://www.mass.gov/files/documents/2016/08/sk/2020-clean-energy-plan.pdf.; *see also* EOEEA, March 2020 Public Sessions Presentation, *available at* https://www.mass.gov/doc/march-public-meeting-slide-deck-for-2050-roadmap ("March 2020 Slide Deck") (noting same); Massachusetts Comprehensive Energy Plan (December, 2018) at Executive Summary, page v, available at https://www.mass.gov/service-details/massachusetts-comprehensive-energy-plan-cep (noting that the building heating/domestic hot water sector represents the second largest source of emissions in the Commonwealth, with nearly two-thirds of that thermal heating demand being met by natural gas); Massachusetts GHG Mitigation and Policies, at Buildings, available at https://www.mass.gov/info-details/ghg-emissions-and-mitigation-policies#buildings- (noting same).

public discussion of the resulting business planning and financial implications of building electrification and related initiatives that will need to be implemented with sufficient lead time to comply with 2050 emission reduction mandates. The Department has both the authority and expertise to initiate this urgent public discussion by promptly opening an investigation that will (1) examine the gas distribution industry, regulatory, and policy changes needed to support the achievement of the Commonwealth's mandated GHG emission limits; and (2) determine what near- and long-term adjustments are necessary to maintain a safe and reliable gas distribution system and protect consumer interests as the Commonwealth transitions from fossil fuels to a clean, increasingly electrified, and decarbonized energy future by 2050.

Like the Department's leadership in examining and implementing new regulatory policies for harmonizing the state's clean energy priorities with electric grid modernization efforts,[3] this investigation provides the Department with the opportunity to solicit utility and stakeholder input and develop a nation-leading regulatory and policy roadmap to guide the evolution of the gas distribution industry companies, provide ratepayer protection, and allow the Commonwealth to move into its net-zero GHG emissions energy future.

---

[3] *See e.g.*, *Vote and Order Opening Investigation*, D.P.U. 12-76 (2012) (investigation into modernization of the electric grid, with workshops and written submissions from stakeholders).

I. BACKGROUND

1. Massachusetts is a national leader in climate action.[4] Accordingly, the legislative, executive, and judicial branches have taken definitive and necessary steps to achieve GHG emissions reduction requirements that will result in an 85 percent reduction in emissions below 1990 levels by 2050 and achieve net-zero emissions. GWSA; Determination of Statewide Emissions Limit for 2020, *supra n.1*.

2. Massachusetts' GHG emissions limits are set forth in several key pieces of legislation enacted in 2008. First, the GWSA set forth target goals for the reduction of GHG emissions from all sectors of the Commonwealth's economy. The current end goal is to reduce GHG emissions by 85 percent by 2050 below the 1990 baseline emission level, with intermediary goals set for 2020 (25 percent reduction) and 2030.[5] Along with the GWSA, the Green Communities Act (St. 2008, c. 169; the "GCA") created a framework to promote enhanced energy efficiency throughout the Commonwealth and required Program Administrators

---

[4] For example, in 2007, Massachusetts led multiple states, cities and other environmental action groups to compel the Environmental Protection Agency ("EPA") to regulate carbon dioxide as a pollutant under the Clean Air Act. *Massachusetts v. EPA*, 549 U.S. 497 (2007). The United States Supreme Court found, among other things, that the "harms associated with climate change are serious and well recognized" and that the EPA has the statutory authority, under the §202(a)(1) of the Clean Air Act, to regulate greenhouse gas emissions. The Supreme Court reasoned that the express language of the Clean Air Act requires the EPA to promulgate regulations to protect the public health and welfare, unless it determines that greenhouse gases do not contribute to climate change. *Id.* In December 2009, the EPA made the endangerment finding that the current and projected concentrations of greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations. Federal Register, Vol. 74, No. 239 (Dec. 15, 2009), Rules and Regulations at 66496.

[5] Determination of Statewide Emissions Limit for 2020, *supra* n.1; *see also* EOEEA 2018 GWSA 10-year progress report, available at https://www.mass.gov/doc/gwsa-10-year-progress-report (providing progress made in achieving the GWSA's 2020 mandate (25 percent GHG reduction below 1990 levels) and finds, based on the Massachusetts Department of Environmental Protection's 2017 GHG inventory, that GHG emissions in the Commonwealth were 22.4 percent below the 1990 baseline level).

(consisting of gas and electric utilities and municipal aggregators with approved energy efficiency plans) to develop energy efficiency plans that would "provide for the acquisition of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply." G.L. c. 25, § 21(b)(1).[6]

3. In May 2016, the Supreme Judicial Court clarified and reaffirmed that the GHG emission reduction limits of the GWSA are mandatory, enforceable emission limits, and not mere aspirational goals. *Kain et al. v. Department of Environmental Protection*, 474 Mass. 278, 288–90 (2016). The Court in *Kain* also underscored that the EOEEA (of which the Department, along with the Department of Environmental Protection, is a part) is primarily responsible for administering the required emission reductions. *See* G.L. c. 21N, § 7; G.L. c. 21A, § 2, clause (30).

4. Similarly, in 2018, the Supreme Judicial Court recognized that the GWSA, "is designed to make Massachusetts a national, and even international, leader in the efforts to reduce the greenhouse gas emissions that cause climate change." *New England Power Generators Assoc., Inc. v. Dep't of Environmental Protection*, 480 Mass. 398, 399 (2018). The Supreme Judicial Court, in upholding the Department of Environmental Protection's authority to promulgate sector specific regulations under G. L. c. 21N, § 3(d), stated that the GWSA "establishes significant, 'ambitious,' legally binding, short-and long-term restrictions on those emissions." *Id.* at 399

---

[6] In 2018, the GCA was amended to provide Program Administrators with the authority to provide a full range of energy services to customers, including energy optimization, energy storage, renewables, active demand response and strategic electrification of home heating. *An Act to Advance Clean Energy*, St. 2018, c. 227. In addition, the Department now recognizes "a localized and reasonable cost value of reducing GHG emissions [that] [] the Program Administrators can claim as one of the benefits of the proposed energy efficiency programs, within the context of contributing to GWSA compliance." *2019-2021 Three-year Energy Efficiency Plans*, D.P.U. 18-110 through 18-119 (2019) at 69–70 (internal citations omitted).

(citations omitted) (also noting that the GWSA "was passed to address the grave threats that climate change poses to the health, economy, and natural resources of the Commonwealth").

5. In September 2016, Governor Baker signed Executive Order 569, which set forth a comprehensive approach to meeting the Commonwealth's GHG emission goals, as well as protecting residents, businesses, and municipalities from the impacts of climate change. On January 21, 2020, in his State of the State address, Governor Baker committed the Commonwealth to achieving economy-wide "net-zero" emissions by 2050. Currently, EOEEA is working to identify cost-effective and equitable strategies to meet the 2050 long-term emission reduction mandates. The EOEEA's "80x50" final report also will inform the determination of the 2030 emissions limit and the development of the CECP for 2030, as well as provide a roadmap to achieve the GWSA's 2050 emissions reduction limit. *See* https://www.mass.gov/info-details/ma-decarbonization-roadmap.[7]

6. Of particular note, the EOEEA has reintroduced pathways identified in its 2020 CECP as foundational strategies to achieve long-term decarbonization and net-zero emissions: "1) Increase Energy Efficiency: Building weatherization, passive house construction, etc.; 2) End-Use Fuel Switching: Electric cars, hydrogen trucks, heat pumps, biofuels, etc.; 3) Expand Clean Energy: Renewable electricity, grid storage, advanced biofuels, etc.; and 4) Increased Carbon Sequestration: Conserving natural lands, best management practices." March 2020 Slide Deck, at slides 20-23.[8]

[7] The EOEEA has undertaken a planning process to identify strategies to ensure Massachusetts reaches its GHG emissions reduction mandates and achieves net-zero emissions by 2050. The EOEEA plans to publish its findings in December 2020. It is the Department's role to ensure that the utility regulatory framework is in place to support these identified pathways.

[8] In December 2010, pursuant to the GWSA, the EOEEA presented its CECP for 2020 to the Legislature. 2020 CECP, *supra* n 2. The 2020 CECP also identified increased energy

7. Taken together, this suite of legislative, judicial, executive, and agency action evinces a strong, central policy goal—across Administrations spanning over a decade—to make the changes necessary to achieve net-zero carbon emissions in the Commonwealth by 2050 to address the urgent threat of climate change quickly and comprehensively. The consensus-identified pathway emerging for the residential and commercial building heating sector, under present technologies, is electrification, powered by low- or zero-emission sources. *See e.g.*, March 2020 Slide Deck (detailing electrification of heating sector as pathway to 2050 goals).[9]

8. As electrification and decarbonization of heating increases, the Commonwealth's natural gas demand and usage from thermal heating requirements will decline substantially and could be near zero by 2050. *Id.* As the Commonwealth reduces its fossil fuel consumption, the Department should establish a consistent regulatory framework that protects customers and maintains reliability and safety during the transition.

II. THE DEPARTMENT'S JURISDICTION TO INVESTIGATE

9. Within the Constitutional limits of its delegated statutory jurisdiction, comprehensive authority "to regulate and control the storage, transportation and distribution of gas . . . is hereby vested in the [D]epartment." G.L. c. 164, § 105A. Further, the Department has plenary authority, on its own motion or on written complaint, to investigate at any time "as to the manner in which . . . gas is being or shall be stored, transported or distributed." *Id.* In construing the scope of power conferred by Section 105A the Supreme Judicial Court noted:

---

efficiency, electrification of the heating sector and expanded clean energy as necessary elements to achieving the 2050 mandated emissions limits.

[9] To better plan for this transition to electrification, commencing with the 2020 Capacity, Energy, Loads and Transmission (CELT) Report, ISO New England has begun forecasting the electrification of heating and its resulting impacts on wholesale electricity power planning and reliability studies. *See* https://www.iso-ne.com/static-assets/documents/2020/02/final-draft-2020-heatelectr-v1.pdf

> [T]he Legislature intended to give, and did give, . . . paramount power to the Department further to regulate and control the storage, transportation and distribution of gas and pressure under which these operations may respectively be carried on in this Commonwealth.

Pereira v. New England LNG Co., Inc., 364 Mass. 109, 120 (1973) (internal citation omitted, and punctuation modified).

10. Analogizing the scope of the Department's plenary authority under G.L. c. 164, § 105A with the Department's preemptive zoning powers related to gas facilities under G.L. c. 40A, §§ 3, 10 the SJC reasoned:

> These two statutes in combination recognize the absolute interdependence of all parts of the Commonwealth and of all of its inhabitants in the matter of availability of public utility services, and they give to the Department the power to take action necessary to insure that all may obtain a reasonable measure of such vital services.

Pereira v. New England LNG Co., Inc., 364 Mass. at 121. Accordingly, a comprehensive investigation into the LDCs' plans to transition to decarbonization is well within the broad authority that the Legislature expressly granted to the Department. Moreover, Section 76 of Chapter 164 affirms that the Department has general supervision of all gas companies and:

> shall make all necessary examination and inquiries and keep itself informed as to the condition of the respective properties owned by such corporations and the manner in which they are conducted with reference to the safety and convenience of the public, and as to their compliance with the provisions of law and the orders, directions and requirements of the department . . . .

In addition, G.L. c. 164, § 69I requires that the Department review every two years the long-range forecast and supply plans of the LDCs. Among other priorities, G.L. c. 164, § 69I directs that these plans consider environmental impacts (defined as land use impact, water resource impact, air quality impact, solid waste impact, radiation impact, and noise impact) and that plans to expand and construct any new gas facilities be "consistent with current health, environmental protection, and resource use and development policies as adopted by the [C]ommonwealth; and are consistent with the policies to provide a necessary energy supply for the [C]ommonwealth with a minimum impact on the environment at the lowest possible cost."

11. Thus, the Department has both the opportunity and the responsibility to undertake a comprehensive review of the LDCs' continuing gas operations in light of, and in furtherance of, the Commonwealth's GHG emission reduction mandates. Indeed, in order to carry out its mandate to ensure continuous provision of these "vital services," and protect the interests of the Commonwealth's ratepayers, such investigation is imperative.

III. SIMILAR PROCEEDINGS IN OTHER STATES

12. On their own initiatives, California and New York's public utilities commissions have recently undertaken similar proceedings.

13. In January, the California Public Utilities Commission ("CA PUC") opened a rulemaking proceeding with the goal of providing a process for the CA PUC to consider challenges relating to California's natural gas infrastructure safety and reliability while the state effectuates its long-term decarbonization goals. CA PUC R.20-01-007 (2020). As part of this proceeding, the CA PUC seeks to develop and adopt updated reliability standards that reflect the current and prospective challenges to gas system operators and to implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies. *Id.*

14. Like Massachusetts' Gas System Enhancement Plans ("GSEP"), in 2011, the CA PUC created the Pipeline Safety Enhancement Plan ("PSEP") process, which requires all gas transmission pipeline operators to outline the replacement and pressure testing of all intrastate natural gas transmission pipelines. CA PUC R.11-02-019 (2011). The total PSEP investment in California is estimated to be well over two billion dollars. CA PUC R.20-01-007 (2020), at 5. At the same time that it created the PSEP process, the CA PUC found that compliance with local

and statewide greenhouse gas legislation will necessitate the decline in natural gas demand for the foreseeable future. *Id.* at 10. Stakeholders recommended that the CA PUC develop long-term plans for phasing out gas utility assets and identify regulatory accounting mechanisms that will mitigate stranded costs for utilities while maintaining affordable gas rates for remaining customers. In addition to its review of safety and reliability regulations, the CA PUC will also develop a planning strategy to balance the impact that the projected gas demand reduction will have on the gas systems with the existing framework to ensure safe and reliable service, *e.g.*, PSEP. *Id.* at 17.[10]

15. In March, the New York Public Service Commission ("NY PSC") opened an investigation "to consider issues related to gas utilities' planning procedures." NY PSC Case 20-G-0131, Order Instituting Proceeding, dated March 19, 2020 (the "Order"). The NY PSC states that it "seeks to establish planning and operational practices that best support customer needs and emissions objectives while minimizing infrastructure investments and ensuring the continuation of reliable, safe, and adequate service to existing customers." Order, at 4. With the passage of its Climate Leadership and Community Protection Act, New York must achieve net-zero greenhouse gas emissions by 2050 and 100 percent emissions-free electric power sources by 2040.

16. In response to these mandated emissions requirements, the NY PSC will examine, among other things, the transparency of gas distribution company planning, non-pipe alternatives, demand response and rate design, as well as any necessary tariff and rule revisions. Within 150 days of the Order, each gas utility must file a "status report and proposals regarding the extent to

[10] The CA PUC set forth a series of questions for the investigation to address. CA PUC R.20-01-007, at 18–20 (including questions regarding long-term natural gas policy and planning).

which the gas utility currently uses or anticipates using demand reducing measures, including energy efficiency, electrification, demand response, non-pipe solutions, and other measures" to meet future demand. Order, at 12. In addition, each gas utility must report on the "potential to target existing and new energy efficiency and electrification programs and budgets to reduce near term and future infrastructure investments and emissions." *Id.*

IV. TOPICS FOR INPUT AND DEPARTMENT CONSIDERATION

17. The Commonwealth's 2050 GHG emission reduction mandate and the anticipated decline in natural gas demand raise many questions regarding the future of gas distribution services and possible changes to the Department's rules and regulations. As an initial starting point, the AGO offers the following particular items for the Department's consideration:

A. Ratepayer Protection, Equity and Fairness

18. How should the Department account for affordability concerns, particularly when the number of gas customers decline as the Commonwealth electrifies its heating sector? What additional policy measures may be necessary to ensure that no customer is left behind in the transition to a clean heating sector? How should principles of equity and fairness serve as benchmarks to protect remaining firm customers?

19. What measures should the Department take to ensure that those least able to pay are not subject to increasing distribution rates as the LDC's revenue requirement is spread over a diminishing customer sales base? Are there rate design safeguards that could help prevent inequitable and disparate impacts?

20. Not all ratepayers, particularly low- to moderate-income customers and residents of environmental justice communities will be able to cost-effectively electrify their home heating

without additional policy measures.[11] What incentives or additional policy measures are necessary to assist in the electrification of their homes (or the adoption of another carbon-neutral alternative)?

21. To the extent some customers remain firm natural gas customers for a longer period, what regulatory measures are necessary to ensure that the LDCs continue to provide safe and reliable gas service as their customer counts decline?

22. Should shareholders pay for the diversification and expansion of the LDC's business operations to meet GHG emission limits? How should the Department determine what is business expansion vs. the provision of a monopoly service that is recoverable in rates?

B. Planning, Forecast and Supply[12]

23. Should the Department adjust its guidelines for review of gas LDCs' forecast and supply plans to require additional long-term forecast data addressing the Commonwealth's transition away from natural gas as a heating fuel? Should the Department require the LDCs to submit modeling/scenario analysis showing the impacts to gas demand in response to decarbonization policy and how that demand projection would affect supply and pricing?

---

[11] Environmental justice communities in Massachusetts have long been among the poorest and most polluted in the Commonwealth. *See e.g.*, *COVID-19's Unequal Effects in Massachusetts*, Report of Attorney General Maura Healey, released May 12, 2020 available at https://www.mass.gov/doc/covid-19s-unequal-effects-in-massachusetts. "[P]olicymakers at every level must work hand in hand with communities in developing and implementing steps to remedy environmental injustice and its attendant public health harms. The voices and experiences of communities of color must play a central role, and community representatives and leaders must be full partners in the work of building an environmentally just future." *Id.* at 8.

[12] Currently, natural gas distribution companies are required to file their long-range forecast and supply plans every two years with the Department. G.L. c. 164, § 69I. By statute, the gas long-range forecast is a five-year forward-looking projection with respect to the gas requirements of an LDC's market area, including the gas send-out necessary to serve projected firm customers and the available supplies necessary to meet the projected demand. *Id.* Also by statute, the LDC's plan must "provide a necessary energy supply for the [C]ommonwealth with a minimum impact on the environment at the lowest possible cost." *Id.*

24. Should the Department require longer-term forecasts, *e.g.*, 10-year or 20-year projections and require the LDCs to assess various methods for meeting future demand, including but not limited to, increased energy efficiency, demand response, electrification, and other carbon-neutral options?

C. Capital Investments and GSEP[13]

25. How much additional LDC investment is prudent in the next 30 years to ensure a safe and reliable gas distribution system, while statewide gas demand declines?

26. Are there other cost-effective alternatives to traditional distribution infrastructure investment that would be better aligned with the Commonwealth's climate goals? Should the Department require gas LDCs to present alternatives when proposing capital investment for system repairs or new gas distribution infrastructure? How should the Department compare and evaluate investment alternatives necessary for the Commonwealth's carbon-neutral energy future?

27. Should the Department require the LDCs, in their GSEPs, to demonstrate continuing need or long-term value for the proposed infrastructure investment and demonstrate how proposed GSEP investments "are consistent with the policies [outlined in G.L. c. 164, § 69H] to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost?"

[13] Pursuant to G.L. c. 164, § 145, a "gas company may file with the Department a plan to address aging or leaking natural gas infrastructure within the Commonwealth in the interest of public safety and reducing lost and unaccounted for natural gas through a reduction in natural gas system leaks."

28. Should the Department require the LDCs, in their GSEPs, to compare GSEP investment with other investment alternatives, *e.g.*, abandoning leak-prone pipes for targeted electrification initiatives and/or geo-thermal projects?

29. Should the Department adjust GSEP planning and cost recovery to mitigate against potentially stranded infrastructure investment, as well as operations and maintenance expenses as a result of declining gas demand? Should accelerated depreciation or retirement of older leak prone infrastructure alternatives be considered? Are there regulatory mechanisms to proactively maintain reasonable rates and mitigate the impact of these investments on remaining firm customers?

D. Other Considerations

30. *Renewable Natural Gas- Biofuel ("RNG"):* What is the potential for RNG to meet future gas demand and deliver verifiable GHG emissions reductions? Is RNG readily available? What considerations are there for scalability and associated operational costs? What infrastructure investment is required to support the widescale use of RNG? What policy or legislative action might be necessary or beneficial to support investment in RNG, *e.g.* RPS-like requirement for RNG?

31. *Renewable Natural Gas- Power-to-Gas ("P2G"):* What is the potential for P2G in Massachusetts? Can P2G deliver verifiable GHG emissions reductions? Have any of the gas distribution utilities investigated the use of hydrogen as a power source? What considerations are there for scalability and associated operational costs? Is there infrastructure investment required to support the widescale use of P2G? What policy or legislative action would be necessary or beneficial to support investment in P2G?

32. *Energy Efficiency Programs:* What is the viability of gas demand resource programs to meet or contribute to emission reduction goals? Are adjustments to current cost-effectiveness screening of energy efficiency programs required to allow for the implementation of a gas demand response program? Can targeted or incremental electrification offset certain future GSEP investment? Does the Department need to review and revise the energy efficiency delivery platform, including the structure of company earned performance incentives, to support achievement of the Commonwealth's climate goals? Should incentive structures be revised to allow for targeted or incremental electrification?

33. Is there an opportunity to convert some amount of fossil fuel residential heating (*e.g.*, oil, propane, natural gas) with geo-thermal network applications? Can existing gas infrastructure or operations be used to support geo-thermal investment? What is the potential for geo-thermal ground source heating technology to meet cost-effectively the heating/cooling needs in the Commonwealth vs. air source heat pump electrification? Should geo-thermal opportunities be administered through program administrators? LDCs? Other market-based third-party organizations? Other governmental agencies? What are the scalability and costs to implement a statewide geo-thermal effort? What policy is required to support investment in geo-thermal networks?

34. *Other technologies:* Are there alternative technologies available (or in development) to electrification that can satisfy the building sector's heating needs and meet the GWSA emission reductions?

35. *Continued Sustainability of Gas Distribution as Usual:* Can the LDCs sustain their current business model as the Commonwealth takes affirmative action to electrify

and decarbonize the heating sector? What does the LDC look like in 2030? 2040? 2050? Are there different business models to be considered? Should LDCs plan to adapt to the new energy future by expanding business lines? What will be required of gas LDCs in meaningfully contributing to the achievement of the Commonwealth's GHG emission reduction mandates? Are there unique opportunities for LDCs that share a parent company with an electric company?

V. PROPOSED PHASED INVESTIGATION

36. The AGO recommends that the Department investigate in two phases. In the first phase, the Department would direct the LDCs to submit detailed economic analyses and business plans depicting future gas demand in a carbon-constrained economy, as well as probable revenues, expenses, and investments. The LDCs would also address the challenges that a substantially decarbonized economy creates for them and present ideas and solutions for the LDCs of the near and far-term future as the Commonwealth transitions its heating sector away from fossil fuels. This first phase also would include stakeholder input regarding issues such as necessary regulatory changes, policy and legislative directives, as well as gas business operation changes necessary to accommodate the Commonwealth's GHG emission mandates.[14] Like its grid modernization investigation in D.P.U. 12-76, the Department could conduct or sponsor workshops or working groups to evaluate and flesh out the submitted stakeholder plans and proposals and to strive for a consensus framework and timeline for future Department action.

37. The second phase of the proposed investigation would seek the development and implementation of the necessary policy, business, and regulatory pathways to achieve the

[14] Stakeholders may also consider proposing alternative business and regulatory models that could sustain the continued operation of gas distribution companies in a decarbonized 2050.

Commonwealth's climate change mandates and protect the Commonwealth's gas consumers. The Department (or working group) could develop straw proposals regarding proposed regulatory, legislative, and policy initiatives required to support the Commonwealth's climate policy and actions, mitigate unnecessary investment in gas distribution assets, and protect ratepayers from increasing gas distribution costs. The utilities and participating stakeholders should have an opportunity to comment on the straw proposals prior to the Department's final order. The Department's final action would be to issue an order providing both the policy and regulatory framework necessary to protect ratepayers and provide necessary guidance for the LDCs regarding the Commonwealth's increasingly decarbonized future.

VI. CONCLUSION

38. Pursuant to its authority pursuant to G.L. c. 164, §§ 76, 105A, the Department should take proactive steps to investigate the future role of the LDCs as the Commonwealth transitions to a clean, increasingly electrified, and decarbonized heating sector. An investigation will provide the platform for the Department to assess fully the prevailing concerns and relevant issues facing LDCs and enable it to develop policies and a regulatory framework to ensure an orderly and fair transition to a clean energy heating sector, to ensure continued safe and reliable gas service even as demand declines, and to ensure that consumers do not pay unnecessary costs.

WHEREFORE, the AGO respectfully requests the Department open an investigation, as described above, to examine the issues facing gas distribution companies as the Commonwealth rapidly moves to achieve its 2050 GHG emission reduction mandate.

Respectfully submitted,

*/s/ Rebecca L. Tepper*____________

Rebecca L. Tepper
Chief, Energy and Telecommunications Division
Jo Ann Bodemer
Donald W. Boecke
Assistant Attorneys General
Massachusetts Attorney General
Office of Ratepayer Advocacy
One Ashburton Place
Boston, MA 02108
(617) 727-2200

Dated: June 4, 2020

Exhibit EDH-5
Case No. 17-G-0460, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan, New York State Department of Public Service, (June 14, 2018).

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 17-E-0459 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service.

CASE 17-G-0460 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.

ORDER ADOPTING TERMS OF JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLAN

Issued and Effective: June 14, 2018

TABLE OF CONTENTS

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on June 14, 2018

COMMISSIONERS PRESENT:

John B. Rhodes, Chair
Gregg C. Sayre
Diane X. Burman, dissenting
James S. Alesi

CASE 17-E-0459 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service.

CASE 17-G-0460 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.

ORDER ADOPTING TERMS OF JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLAN

(Issued and Effective June 14, 2018)

BY THE COMMISSION:

INTRODUCTION

This order establishes a three-year rate plan for electric and gas service provided by Central Hudson Gas & Electric Corporation (Central Hudson or Company), for the period July 1, 2018, through June 30, 2021. The order adopts terms of a Joint Proposal (JP) executed by the Company; the New York State Department of Public Service trial staff (Staff); Multiple Intervenors (MI); Pace Energy and Climate Center (Pace); New York Geothermal Energy Organization (NY-GEO); the Utility Intervention Unit of the Department of State, Division of

Consumer Protection (UIU); Dutchess County; Acadia Center; the Public Utility Law Project of New York, Inc. (PULP); the Natural Resources Defense Council (NRDC) (partial); Bob Wyman; and the U.S. Army Legal Services Agency, representing the U.S. Department of Defense and all other Federal Executive Agencies (Army Legal Services).

BACKGROUND OF THE PROCEEDING

Central Hudson distributes electricity to approximately 300,000 customers and natural gas to about 80,000 customers in the Mid-Hudson River Valley region of New York.[1] The Company's most recent electric and gas rate plan was adopted in a rate order issued in June 2015.[2] In that order, the Commission approved the implementation of a three-year electric and gas rate plan for Central Hudson.

On July 28, 2017, Central Hudson filed tariff leaves and testimony seeking to increase its electric and gas delivery revenues based on a rate year starting July 1, 2018, and ending June 30, 2019 (Rate Year). Central Hudson also included select financial information for two additional rate years. Central Hudson's proposed delivery rates were designed to produce an electric delivery revenue increase of approximately $63.4 million and a gas delivery revenue increase of approximately $22.2 million, resulting in delivery revenue increases of 21.2% and 24.3%, respectively, or total system-wide revenue increases

---

[1] Hearing Exhibit 1, Pre-filed direct testimony of Company Witness Buckley, p. 31.

[2] Cases 14-E-0318 and 14-G-0319, Central Hudson Gas & Electric Corporation – Rates, Order Approving Rate Plan (issued June 17, 2015) (2015 Rate Order).

of 12% and 18%, respectively.[3] Central Hudson requested a 9.5% overall return on equity and an equity ratio of 50%.[4]

The presiding administrative law judges (ALJs) held a procedural conference and a technical conference on September 7, 2017. By ruling issued September 19, 2017, they established a case schedule requiring the filing of Staff and intervenor testimony on November 21, rebuttal testimony on December 15, and the commencement of an evidentiary hearing on January 9, 2018. By ruling issued September 29, 2017, the ALJs granted a request for reconsideration of a portion of that schedule and established a revised rebuttal filing due date of December 18, 2017.

The Company filed supplemental testimony and exhibits on October 19, 2017. Staff, UIU, MI, NRDC, PULP, Pace, Dutchess County, Bard College, Bob Wyman, and Citizens for Local Power (CLP) filed direct testimony. In its testimony, Staff noted that the Company's proposed electric revenue increase had been revised to \$66.2 million (a 22.1% delivery revenue increase). Among other things, Staff recommended an electric revenue increase of \$27.8 million, a gas revenue increase of \$7.6 million,[5] an overall return on equity of 8.3%, and an equity ratio of 48%.[6] Staff's recommended revenue increases included the impact of collecting energy efficiency related costs through base rates, as opposed to through a surcharge. This proposal

---

[3] Hearing Exhibit 22, Joint Proposal, p. 2.

[4] Hearing Exhibit 1, Pre-filed direct testimony of Company Witness Buckley, p. 5.

[5] Hearing Exhibit 16, Pre-filed direct testimony of Staff Accounting Policy and Revenue Requirements Panel, pp. 10-11.

[6] Hearing Exhibit 16, Pre-filed direct testimony of Staff Finance Panel, pp. 9-10.

would result in a base rate increase of $8.5 million for electric and $0.8 million for gas, but no net bill impact.

By letter dated December 8, 2017, Central Hudson filed a notice of impending settlement negotiations, advising that the first negotiation session would be held on December 21, 2017, in Albany. In accordance with the Commission's rules, the required review of the notice was completed and reported, also on December 8.

Rebuttal testimony and exhibits were filed by the Company, UIU, Pace, MI, and CLP. On December 21, 2017, Central Hudson requested the postponement of the evidentiary hearing that was scheduled to commence on January 9, 2018, to facilitate the settlement discussions and allow additional time to negotiate and finalize a joint proposal. Thereafter, several additional postponements were requested and granted.

The settlement negotiations ultimately proved successful, resulting in the filing of the April 18, 2018, JP between the Company, Staff, MI, Pace, NY-GEO, UIU, Dutchess County, Acadia Center, PULP, NRDC, Bob Wyman, and Army Legal Services (collectively, the Signatory Parties). The Signatory Parties assert that the JP, together with its accompanying appendices, contain a comprehensive set of terms and conditions for a three-year rate plan for Central Hudson's electric and gas service. They recommend that the rates and surcharges of Central Hudson be determined in accordance with the understandings, principles, qualifications, terms, and conditions set forth therein. The filing of the JP was accompanied by a summary of the JP, bill impact tables, and a scheduling proposal.[7] Statements in support of the JP were filed by the Company, MI, Pace, Acadia Center, PULP, NY-GEO, Bob Wyman, and Staff.[8] CLP filed a statement on the JP. No party filed a statement opposing the JP. On May 9, the Company filed a letter in lieu of reply statement in support of the JP. An evidentiary hearing was held on May 21, 2018.[9]

PUBLIC COMMENTS AND NOTICE OF PROPOSED RULEMAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), Notices of Proposed Rulemaking were published in the State Register on October 11, 2017 (SAPA No. 17-E-0459P1 and SAPA No. 17-G-0460P1).

On September 11, 2017, a notice was issued describing the Company's rate filing and announcing the dates, times, and locations of six public statement hearings and public information sessions. The notice further stated that comments also could be made by internet, mail, or the Commission's toll-free Opinion Line. Consistent with the notice, afternoon and evening public information sessions and public statement hearings were held in Poughkeepsie, Kingston, and Newburgh, on October 3, 10, and 16, 2017, respectively.[10] Between two to 20 people spoke at each public statement hearing and five to 45 people attended each hearing.

---

[7] On April 19, 2018, a Ruling on Schedule was issued establishing the due dates for filing initial and reply statement on the JP and the start date of the evidentiary hearing.

[8] On May 8, 2018, Staff filed a letter clarifying and correcting portions of its statement in support.

[9] See Notice of Evidentiary Hearing (issued May 2, 2018).

[10] Commissioner Sayre presided at the Poughkeepsie public statement hearings and Commissioner Burman presided at the public statement hearings in Newburgh.

After the Joint Proposal was filed, an April 20, 2018, Notice was issued establishing a further period for public comments on the JP.

Public Statement Hearing Comments

Comments were made by 15 people at the Poughkeepsie hearings, 33 people at the Kingston hearings, and 17 people at the Newburgh hearings. Most individuals spoke on their own behalf, while others commented on behalf of various educational institutions, environmental groups, and other nonprofit organizations. Frank Skartados and Kevin Cahill of the New York State Assembly, as well as other local elected officials, also spoke at the hearings.

Most commenters opposed the Company's requested rate increases in their entirety. Comments generally focused on the issues of affordability, even at the existing rates, especially with respect to residential customers living on fixed or limited incomes who also are facing rising costs for necessities such as groceries, prescription medications and health insurance. Various commenters stated that Central Hudson's delivery rates already were too costly, especially for the large population of low income customers in the Company's service territory, and that the requested increases were too much and simply would ensure more profits for the Company. Similarly, commenters noted that there were already too many utility shut-offs of the Company's customers. Commenters also complained about Central Hudson's high fixed customer charge.

Some commenters said that the Company should expand its energy efficiency and conservation programs, focus on increasing the use of renewable resources, use rate structures such as time-of-use options to promote conservation, and use its profits to pay for needed infrastructure upgrades. Other commenters questioned Central Hudson's intended use of the rate increases, noting that the Company had relied on several of the same categories of increased costs to raise rates previously, without any corresponding increase in service quality or reliability.

A few commenters mentioned the high costs of vegetation management and the Company's claimed need to address trees affected by the Emerald Ash Borer Beetle, expressing that the costs appeared to be inflated for the tree and vegetation clearing program. Others expressed concern with the Company's proposed training facility, opining that adequate training facilities already existed in the local communities. Several individuals also expressed concern with the Commission's prior approval of the Fortis Inc. acquisition of Central Hudson.[11] One commenter expressed concerns with the potential impact of the rate increase on the small-business community, while other individuals stated that the proposed rate increases would have a disproportionate impact on residential customers.

Written Comments and Opinion Line Comments

In addition to the public statement hearing comments, almost 800 comments were received either through the Commission's opinion line or filed with the Commission's Secretary. Virtually all the written and opinion line comments received were from individual customers expressing opposition to the proposed rate increases. There were, however, a few comments received after the Joint Proposal was filed that expressed support for the reductions from the Company's initial filing that are reflected in that proposal.

[11] See Case 12-M-0192, Joint Petition of Fortis Inc. et al. and CH Energy Group, Inc. et al. for Approval of the Acquisition of CH Energy Group, Inc. by Fortis Inc. and Related Transactions.

Citing low or nonexistent cost-of-living adjustments and rising costs for necessities like housing, food, prescriptions and health insurance, many commenters stated that the proposed rate increases were too high, especially for people on low or fixed incomes, and that the Company should reduce executive compensation or other Company profits to fund any cost and expense increases. Some commenters stated that the Company should not receive any increases given the Company's current level of profits.

Numerous commenters, including various Town, City and County officials, stated that fixed customer charges are too high and need to be reduced. They said that high fixed charges not only minimize incentives to conserve energy and to invest in renewable energy systems, but also undermine Reforming the Energy Vision (REV) policy initiatives seeking to give consumers more control over energy use and costs, and have a disproportionate impact on moderate and low income customers who purportedly use less energy than average. Finally, several commenters stated that the Company already shuts off service for too many customers for nonpayment and that an increase in rates will only exacerbate the problem.

SUMMARY OF JOINT PROPOSAL[12]

Term[13]

The JP proposes a three-year rate plan for Central Hudson's electric and gas businesses that would begin on July 1, 2018, and continue until June 30, 2021. Rate Year 1 consists of

---

[12] In the following discussion, some terms of the JP, along with any issues related thereto, are generally summarized and discussed. The summary is provided for the reader's convenience.

[13] Hearing Exhibit 22, Joint Proposal, §III.

the 12-month period beginning on July 1, 2018, and ending June 30, 2019. Rate Years 2 and 3 consist of the next two successive 12-month periods ending June 30, 2020, and June 30, 2021, respectively. Unless specifically noted otherwise, the provisions of Rate Year 3 would remain in effect until superseding rates or terms become effective.

Revenue Requirements[14]

The JP would increase electric and gas base delivery revenues in each of the three rate years. The JP recommends electric delivery revenue increases of $19.725 million in Rate Year 1, $18.581 million in Rate Year 2, and $25.083 million in Rate Year 3, and gas delivery revenue increases of $6.654 million in Rate Year 1, $6.702 million in Rate Year 2, and $8.183 million in Rate Year 3. To mitigate the customer bill impacts that would be associated with these increases, the proposed increases have been moderated by using available regulatory liabilities and applying them as credits. After applying credits totaling $6 million in Rate Year 1, $9 million in Rate Year 2, and $11 million in Rate Year 3, the net electric delivery revenue increase will be $13.725 million in Rate Year 1, $15.581 million in Rate Year 2, and $23.083 million in Rate Year 3. After applying credits totaling $3.5 million in Rate Year 1, $4.0 million in Rate Year 2, and $4.0 million in Rate Year 3, the net gas delivery revenue increases will be $3.154 million in Rate Year 1, $6.202 million in Rate Year 2, and $8.183 million in Rate Year 3. These amounts include the impact of Staff's proposal to collect energy efficiency-related costs through base rates, as opposed to through a surcharge. This change resulted in a base rate increase of $8.5 million for electric and $0.8 million for gas, but no net bill impact.

---

[14] Id., §IV.

The Rate Year 1 delivery revenue increases include the impact of Staff's proposal to collect energy efficiency-related costs through base rates, as opposed to through a surcharge. Because the Company will no longer collect these costs through a surcharge, the Rate Year 1 electric delivery revenue increase experienced by customers is offset by an $8.479 million surcharge reduction and the Rate Year 1 gas delivery revenue increase experienced by customers is offset by a $0.837 million surcharge reduction. This results in a Rate Year 1 net increase experienced by customers for electric service of $5.246 million, or approximately 1% of their total bill and a net increase experienced by customers for gas service of $2.317 million, or approximately 1.5% of their total bill. [15]

The net increases experienced by electric customers for Rate Year 2 of $15.581 million, or about 2.8%, and for Rate Year 3 of $23.083 million, or approximately 4%, are not impacted by the shifting of energy efficiency-related costs from a surcharge to base rates. The same is true for the net increases experienced by gas customers for Rate Year 2 of $6.202 million, or 3.6%, and for Rate Year 3 of $8.183 million, or 4.4%.

Equity Ratios, Return on Equity, and Earnings Sharing Mechanism[16]

The revenue requirements for all three years of the proposed rate plan are based on a capital structure with a common equity ratio of 48% in Rate Year 1, 49% in Rate Year 2, and 50% in Rate Year 3, and an allowed return on common equity (ROE) of 8.8%. The JP includes an earning sharing mechanism (ESM) that is triggered if Central Hudson's actual ROE in any year, after certain adjustments, exceeds 9.3%. Earnings above

---

15 The estimated percentage increases experienced by customers is calculated assuming the Company's delivery revenues represents 60% of the customers' total bills.

16 Id., §VI.A.

9.3% and up to 9.8% would be shared equally between the Company and ratepayers; ratepayers would receive 80% of any earnings over 9.8% up to 10.3%; and ratepayers would receive 90% of any earnings over 10.3%.

Electric and Gas Revenue Allocation and Rate Design[17]

JP Appendix L sets forth the signatories' agreed-to electric and gas revenue allocation. JP Appendix M sets forth the signatories' agreed-to electric and gas rate design.

The electric bill credits will be allocated to each service class in proportion to class responsibility for the overall delivery rate increase and will be refunded to customers on kilowatt-hour (kWh) or kilowatt (kW) basis through the existing Electric Bill Credit Mechanism. The gas bill credits will be allocated to each service class in proportion to class responsibility for the overall delivery rate increase and will be refunded to customers on a hundred cubic feet (Ccf) basis through the existing Gas Bill Credit Mechanism which is applicable to firm Service Classifications (SCs) 1, 2, 6, 11 (Distribution Large Mains (DLM), Distribution (D) and Transmission (T)), 12, and 13. For billing purposes, any applicable credit up to $1 million resulting from Service Classification (SC) 11 gas delivery service to the Danskammer Generating Station (see JP Section IX.A) will be included in and combined with the Gas Bill Credit, thus appearing as one line item on customer bills.

The JP provides that the current customer charge for certain electric customers (i.e., SC 1 residential, SC 2 non-demand, and SC 6 residential time-of-use) and the minimum charge for SC 1 residential gas customers will be reduced by $3.00 in

[17] Id., §X.

Rate Year 1, $1.00 in Rate Year 2, and $0.50 in Rate Year 3.[18] As a result, the SC 1 residential electric customer charge will be $21.00 in Rate Year 1, $20.00 in Rate Year 2, and $19.50 in Rate Year 3. The SC 1 gas residential minimum charge will decrease by $1.00, $0.50, and $0.25 in Rate Year 1, Rate Year 2, and Rate Year 3, resulting in a minimum charge of $25.00 in Rate Year 1, $24.50 in Rate Year 2, and $24.25 in Rate Year 3. The JP notes that future changes to these charges may be decided in other related proceedings, including, but not limited to, the Value of Distributed Energy Resources (VDER) proceeding.[19]

The JP calls for the establishment of a three-part rate for the gas service provided pursuant to the SC 11 tariff (the Firm Transportation Rate) that would consist of (1) a monthly minimum charge; (2) a volumetric charge applicable to a customer's monthly consumption exceeding 1,000 Ccf per month; and (3) a demand charge applicable to a customer's Maximum Daily

---

[18] The current electric customer charges are $24.00 for SC 1 (residential), $35.00 for SC 2 (general service, non-demand), and $27.00 for SC 6 (residential time-of-use). The current minimum charge for SC 1 residential gas service is $26.00. See Hearing Exhibit 1, Pre-filed direct testimony of Central Hudson's Forecasting and Rates Panel, pp. 54, 58.

[19] Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources.

Quantity (MDQ).[20] In addition, the three SC 11 transmission rates from the 2015 Rate Plan[21] will be combined into one transmission rate called SC 11 Transmission and the two SC 11 distribution rates from the 2015 Rate Plan[22] will be combined into one distribution rate called SC 11 Distribution, while SC 11 DLM rate will be maintained.[23] The volumetric rate will be set to recover approximately 15% of delivery revenue allocated to SC 11 with the remaining estimated revenue less the minimum charge being recovered through the MDQ charge.

---

[20] The existing SC 11 tariff entitled "Firm Transportation Rate – Core" is applicable to use of service for transportation of customer-owned gas to those customers that have the capability of transporting and receiving at one service point 75,000 thousand cubic feet (Mcf) or greater per year where: 1) the customer's premises are (a) located adjacent to the Company's existing gas mains having adequate capacity to supply customer's prospective requirements in addition to the simultaneous requirements of present or prospective customers taking firm or interruptible service from such mains; or (b) at other points under arrangements made in accordance with General Information, Section 25; and 2) service is to be provided under an agreement as included in General Information, Section 40.

[21] i.e., Transmission Annual x<300,000 Mcf, Transmission Annual 300,000<x<800,000 Mcf and Transmission Annual x>800,000 Mcf.

[22] i.e., Distribution Annual x<100,000 Mcf and Distribution Annual x>=100,000 Mcf.

[23] JP Appendix M indicates that SC 11 subclass, Electric Generation (SC 11 EG), also will be maintained. This subclass, established July 1, 2015, applies to electric generation facilities with a minimum generation capacity of 50 megawatts taking firm natural gas transportation service from Central Hudson facilities at transmission pressures. See 2015 Rate Order, p. 35.

Net Plant Targets and Reconciliations[24]

Electric and Gas Net Plant Targets[25]

JP Appendix C sets forth the depreciation expense targets and the net plant targets upon which the electric and gas revenue requirements are based. These targets are applicable only to the time periods specified in the JP. Actual average electric and gas net plant balances and depreciation expense at the end of each Rate Year will be calculated using the calculation methods described in JP Appendix D.

Net Plant Target Reconciliations[26]

The JP provides that actual electric and gas net plant balances and depreciation expense will be reconciled to the combined electric and gas net plant targets and depreciation expense targets for Rate Year 1, Rate Year 2, and Rate Year 3 on an annual Rate Year basis. The revenue requirement impact (i.e., return and depreciation as described in Appendix D) resulting from the total difference (whether positive or negative) between actual average net plant balances and depreciation expense and the combined target levels will carry forward for each of the Rate Years and will be summed algebraically at the end of Rate Year 3.

---

24 Hearing Exhibit 22, Joint Proposal, §V.A.2.

25 Actual Net Plant and the Net Plant Targets have the following components: 1) the Average Electric or Gas Net Plant; 2) the Average Electric or Gas Non-Interest Bearing Construction Work in Progress (NIBCWIP); 3) the Average Common Net Plant allocated to Electric or to Gas; and 4) the Average Common NIBCWIP allocated to Electric or to Gas. Hearing Exhibit 22, Joint Proposal, §V.A.

26 Hearing Exhibit 22, Joint Proposal, §V.A.3.

Deferral for the Benefit of Ratepayers[27]

If, at the end of Rate Year 3, the cumulative incremental revenue requirement impact from net plant balances and depreciation expense differences is negative, the Company will defer the revenue requirement impact for the benefit of customers; if it is positive at the end of Rate Year 3, no deferral will be made. Carrying charges at the pre-tax rate of return will be applied by the Company to the amount deferred from the end of Rate Year 3 until the date that the Company's next rate order takes effect.

Existing Reporting[28]

The Company will continue to provide Staff with yearly reports, due by March 1 of each year, on its capital expenditures during the prior calendar year. The Company also will continue to annually file its five-year capital investment plan with the Secretary to the Commission; this report will be filed by July 1 and will include an explanation of any cost variance between the approved budget and an actual expenditure greater than 10% for any single project identified in the Company's Major Capital Project Report shown in JP Appendix E, Sheet 1. The proposed three-year capital investment plan is set forth in JP Appendix Y.

New Reporting[29]

The Company will be subject to two new reporting requirements, 1) a quarterly capital variance report and 2) a detailed annual report that identifies planned information technology (IT) projects. The IT report will include: (1) the final variance summary of all on-going and active capital

---

[27] Id., §V.A.4.

[28] Id., §V.A.5.

[29] Id., §V.A.6.

projects and programs; (2) an explanation of any cost or timeline exceeding 10% of forecast; (3) a narrative on changes to any IT project design, contracts, or software; (4) a description of benefits of any new IT projects or programs; and (5) any quantitative benefit/cost analysis to date and/or forecast, including the methodology used. Starting with the quarter ending March 31, 2019, the Company will file with the Secretary the first of its quarterly reports that will include: (1) any changes to the IT project prioritization with an explanation; (2) the expense variance by project; and (3) an explanation for any cost variance exceeding 10% of the project's approved budget.[30]

Deferral Accounting[31]

The JP provides for the continuation, without modification, of numerous accounting deferrals for revenues, expenses, and costs, including but not limited to, Environmental Site Investigation and Remediation (SIR) Costs, Pension Expense and Post-Employment Benefits Other than Pensions (OPEBs), Property Taxes, and REV Demonstration Projects. The JP specifies the modification of several other 2015 Rate Plan accounting deferrals including, for example, the ESM, Economic Development, the Low Income Program, the Electric Revenue Decoupling Mechanism (RDM), Right-of-Way Tree Trimming Costs, and Gas Leak Prone Pipe (LPP). The JP lists the accounting deferrals from the 2015 Rate Plan that will expire. Finally, it lists the new accounting deferrals that will be added. A summary listing of accounting deferrals and applicable examples is set forth in JP Appendix F, together with the specific deferral method and associated carrying charge for each. The

---

30 See id., Appendix P.

31 Id., §V.B.

accounting deferrals that are authorized by the terms of this JP will not terminate at the end of Rate Year 3, but instead are intended to continue until they are superseded or expressly revoked.

Impact of Federal Tax Changes

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (Tax Act) was signed into law. The Tax Act significantly lowered the Company's federal income tax expense, starting in 2018. The JP reflects the Signatory Parties' best estimate of the impact the Tax Act will have on expenses for the three years of the rate plan. Staff states that Rate Year 1 revenue requirements were lowered by approximately $13.2 million for electric and $4.8 million for gas due to the decrease, from 35% to 21%, in the federal income tax rate applicable to the Company.[32] The revenue requirement impact that the Tax Act has on the January 1, 2018, to June 30, 2018, time period, the six months when the Tax Act is in effect but before the rate plan in the JP begins, will be deferred for future customer benefit and we will address such balances at a future time.

Low Income Customer Provisions[33]

The JP notes that low income discounts will be provided to Home Energy Assistance Program (HEAP) recipients, consistent with the requirements set forth in the orders issued

---

[32] Staff Statement in Support of Joint Proposal (Staff Statement), p. 31.

[33] Id., §XI.

by the Commission in the generic proceeding.[34] The annual funding for these credits total $8.612 million in Rate Year 1, $11.015 million in Rate Year 2, and $12.018 million in Rate Year 3. The specific bill discount credits, set forth in the electric and gas tariffs, may change based on the annual Low Income Plan the Company is required to file with its analysis of customer bills. However, as proposed in the JP, eligible low income customers will receive monthly low income discounts ranging from $19.00 to $72.00.[35]

The level of funding for the bill discount credits is subject to symmetrical deferral.[36] Any accumulated balances of program under-spending will be deferred for future use in the Low Income Program and carrying charges will be applied at the pre-tax rate of return. If higher than forecasted participation renders the rate allowance specified for the discounts inadequate to provide them to all qualifying customers, the Company is authorized to defer the difference between the rate allowance and the actual discounts.

The Low Income Order authorized the continuation of an Arrears Forgiveness Program that will be phased out during Rate Year 2. The JP therefore provides for total allowances for this

---

[34] Case 14-M-0565, Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers, Order Adopting Low Income Program Modifications and Directing Utility Filings (issued May 20, 2016)(Low Income Order), and Order Granting in Part and Denying in Part Requests for Reconsideration and Petitions for Rehearing (issued February 17, 2017)(Low Income Rehearing Order).

[35] This range assumes that the customer receives a heating discount for one fuel type. Eligible non-heating low income customers will receive discounts ranging from $3.00 to $56.00.

[36] See Hearing Exhibit 22, Joint Proposal, §V.B.2.e.

program of $142,000 in Rate Year 1 and $6,000 in Rate Year 2. These allowances also are subject to symmetrical deferral.

The Low Income Order also authorized the continuation of the waiver of Reconnection Fees. The JP notes that an allowance of $51,000 for each Rate Year (split 80/20 between electric and gas), also subject to symmetrical deferral, has been established.

Tariff Related Matters[37]

Existing tariff provisions and related rate making will generally be continued, but with some exceptions and modifications, such as including storage batteries in the definition of "designated technologies" under section 14.5 of the standby service tariff; combined Nitrous Oxides emissions for designated technologies exempt from standby rates under section 14.5 will be reduced under 4.4 lbs/megawatt hour (MWh) to 1.6 lbs/megawatt (MW) under the standby service tariff for customers that complete a Coordinated Electric System Interconnection Review (CESIRs) on or after July 1, 2018 (CESIRs completed before July 1, 2018, will be grandfathered under the 4.4 lbs/MWh standard); graduated increases in reconnection charges applicable to service restoration to the same customer at the same meter location within 12 months after discontinuance of service; and expanding the electric RDM to additional customer classifications, and implementing a new Gas Miscellaneous Charge mechanism and bill line item to address the recovery and refund of new initiatives.

Energy Efficiency[38]

The JP provides that, beginning in Rate Year 1, Central Hudson's electric and gas Energy Efficiency Transition

37 Id., §XII.

38 Id., §XIII.

Implementation Plan (ETIP) costs will be recovered in base rates instead of the Energy Efficiency Tracker Surcharge portion of the System Benefit Charge (SBC).[39] The annual electric and gas ETIP costs included in base delivery rates are $9.8 million and $1.2 million, respectively.[40]

Training Center[41]

In its initial testimony, the Company proposed to construct an integrated and modern facility dedicated to providing hands-on and scenario-based learning and indoor/outdoor electric and gas training (the Training Center). The Company also proposed to construct an integrated transmission and distribution system operations center (the Primary Control Center).[42] The centers were proposed to be co-located, with the Training Center estimated to cost

---

[39] The Company will apply an appropriate credit to those customers that currently have exemptions from the Energy Efficiency Tracker Surcharge portion of the SBC, such that the credit will preserve the economic value of the exemptions that otherwise would be lost by shifting the recovery of electric and gas ETIP costs from the SBC to base rates. To the extent a service class is not included in the RDM and the actual value of such exemptions provided differs by $10,000 or more from the value imputed in base rates (see Hearing Exhibit 22, Joint Proposal, Appendix M, Sheets 5 through 7), the entire difference will be deferred for future disposition subject to Commission approval.

[40] Central Hudson’s Energy Efficiency Program costs and targets are subject to change pursuant to Commission action in Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative. If the Commission does not provide specific cost recovery directives for any modifications to such budgets, the JP would authorize the Company to defer and recover any such changes approved by the Commission.

[41] Hearing Exhibit 22, Joint Proposal, §XV.

[42] See Hearing Exhibit 1, Pre-filed testimony of Central Hudson’s Training and Development Panel, and of Witness Anthony S. Campagiorni (Policy and Overview).

approximately $32.5 million while the Primary Control Center spending would be $2.2 million in 2018 and $1.7 million in 2019.[43]

The JP states, in relevant part, that within 30 days of the Commission's issuance of a final order in these proceedings, the Company will file an initial report with the Secretary containing the proposed Training Center and the scope of the Primary Control Center Projects (Projects) and a timeline of major performance milestones, including deadlines for functional capability and operation/integration of the Projects and the Company's expected incremental capital expenditures and operating expenses that would be incurred if the Projects are not pursued. Within 60 days after this filing, the JP states that Staff and the Company will meet to discuss the major performance milestones timeline and, if they do not reach agreement regarding said milestones, either the Company or Staff may seek a ruling from the Commission regarding appropriate milestones. Thereafter, the Company would file with the Secretary a major milestone performance report within 30 business days of a milestone completion date (Milestone Report) that describes, *inter alia*, the Projects' compliance with the applicable milestone(s); identifies the Company's view of the Projects' direct customer benefit(s); describes the electric and gas business impacts; and, if necessary, also indicates potential and appropriate remedial action for a specific Project that has not fully met a milestone. Finally, Staff will present its review of the Milestone Report(s) to the Director of the Office of Electric, Gas and Water for approval and the Director's approval of the continuation of the Projects shall be

[43] See Hearing Exhibit 1, Pre-filed Exhibits of Central Hudson's Training and Development Panel, TDP-3.

documented in a letter from the Director to the Company with a copy filed with the Secretary.

Electric Reliability[44]

We are mindful of the severity of recent storms and the impact to customers that prolonged outages bring. As the Department conducts its comprehensive statewide investigation into the utility companies' preparation and response to those events, which may lead to a variety of recommendations for different companies, the Commission encourages the Company to continue to consider its approaches to reduce the likelihood of storm damage and enhance its storm response activities.

The JP recommends continuation of the electric service annual metrics for System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI).[45] SAIFI, which is currently set at or below 1.30 will be set at the following targets: (1) 2018 - 1.38; (2) 2019 - 1.34; and (3) 2020 - 1.30. The slightly increased 2018 and 2019 SAIFI targets reflect our acknowledgment that the Emerald Ash Borer is causing unprecedented danger tree-related risks. Adopting the SAIFI targets set forth in the JP will provide the Company with the ability to implement the Emerald Ash Borer Danger Tree Program while still requiring the Company to maintain and improve reasonable reliability performance levels. The target for CAIDI will continue to be set at or below 2.50.

---

[44] Id., §XVI.

[45] Electric reliability performance is primarily measured by the Commission utilizing the SAIFI and CAIDI indices. SAIFI is the average number of times that a customer is interrupted for five minutes or more during a year, while CAIDI is the average interruption duration time in hours for those customers that experience an interruption during the year. See, e.g., New York State Department of Public Service, 2016 Electric Reliability Performance Report, filed session of June 15, 2017.

Potential negative revenue adjustments for SAIFI and CAIDI can be incurred up to 30 basis points each, or up to about $4.1 million total, if the Company fails to achieve these targets.

Gas Safety[46]

The JP continues and further enhances existing gas safety performance metrics and safety programs. Specifically, the JP provides that the Company will continue to replace LPP at a rate of 15 miles per year and increases the Company's negative revenue adjustment from eight basis points to 12 basis points for failing to achieve this target.[47] The JP recommends cumulative potential negative revenue adjustments for the Company's gas operations of up to 150 basis points and recommends up to 43 basis points of positive revenue adjustments for surpassing various gas safety metrics, including LPP replacement, Type 3 leak reduction, emergency response, and damage prevention.[48]

The JP recommends the creation of new gas safety programs, including residential methane detection and first responder training. Within 60 days, the Company will file an implementation plan for its Residential Methane Detection Program. Within 120 days, the Company will file an implementation plan for its First Responder Training Program. Both programs will be funded with code rule violation negative revenue adjustments that the Company may incur as part of its safety performance metrics. Any costs in excess of the available amounts may be deferred.

---

[46] Id., §XVII.

[47] The 2019 pre-tax dollar value of 12 basis points equals $309,000.

[48] For 2019, the pre-tax dollar value of 150 basis points would be $3.9 million. The 2019 pre-tax dollar value of 43 basis points is $1.1 million.

The JP requires the Company to submit an implementation plan for each identified non-pipe alternative and provides an incentive to the Company to seek out these alternatives to traditional gas infrastructure investments. It is envisioned that the identified non-pipe alternatives would include projects that will reduce peak day demand, as well as provide for transportation mode alternatives. The Company will also be required to issue a request for proposals to solicit technology and fuel neutral market responses to a defined level of peak reduction and then determine the value of various levels of peak reduction provided by a Demand Response program.

Customer Service[49]

The JP introduces new Customer Service initiatives, including the elimination of fees associated with payments made by credit/debit card or at walk-in locations and the Company's agreement to study the feasibility of implementing an electronic Deferred Payment Agreement (DPA) program. The JP establishes more stringent targets for existing Customer Service Quality Performance Mechanisms, including the Customer Satisfaction Index and the Public Service Commission (PSC) Complaint Rate. In addition, the JP provides for the implementation of a new Call Answer Rate metric and a new mechanism designed to encourage the Company to reduce both residential service terminations and residential uncollectibles. The JP also provides funding for additional customer service employees over the term of the Rate Plan.

The JP provides for a maximum total of $3.0 million or about 32 basis points of negative revenue adjustments across both electric and gas operations if the Service Quality metrics are not met. In addition, a positive revenue adjustment of

---

49 Id., §XVIII.

$925,000 or about 10 basis points is provided for exceeding goals relating to residential terminations and uncollectibles. As noted above, Central Hudson's residential termination practices were identified as one of the areas where the Company's practices should be improved; establishing this positive revenue adjustment should encourage the Company to reduce the number of residential terminations.

Earnings Adjustment Mechanisms[50]

The JP recommends adoption of various Earnings Adjustment Mechanisms (EAMs). The proposed electric EAMs are intended to provide the Company with incentives to: 1) increase electric system efficiency through peak reduction and distributed energy resource utilization; 2) increase achieved electric and gas energy efficiency; 3) reduce residential and commercial customers' electric energy intensity (total usage on a per customer basis); 4) increase residential customer participation in voluntary Time of Use rates; and 5) reduce carbon emissions through increased penetration of emissions-reducing technologies. The JP also recommends allowing the Company to petition for approval of Interconnection EAM targets. The Gas Energy Efficiency EAM is intended to incentivize the Company to achieve energy efficiency savings that are significantly above 37,296 dekatherms (Dth).[51]

Central Hudson has the potential to earn a maximum earnings adjustment of $2.0 million in 2018, $4.3 million in calendar year 2019, $4.7 million in calendar year 2020, and $4.9 million in calendar year 2021 for its electric business. With

50 Id., §XXI.

51 37,296 dekatherms (Dth) is the current net savings target for the gas ETIP.

respect to the gas business, Central Hudson has the potential to earn a maximum earnings adjustment of $0.18 million in 2018, $0.39 million in calendar year 2019, $0.44 million in calendar year 2020, and $0.47 million in calendar year 2021.[52] The financial consequences of EAMs will be excluded from the computations of actual regulatory earnings.[53]

Geothermal Rate Impact Credit[54]

The JP establishes a geothermal rebate or "rate impact credit" to facilitate installations of this emerging technology.[55] The credit will be funded by incremental heating usage that would be monetized and provided to non-participants through the RDM. To qualify for the annual $264 rate impact credit, a customer must have equipment that meets the requirements of the New York State Energy Research and Development Authority (NYSERDA) Geothermal Rebate Program, and the customer must enroll in Central Hudson's Insights+ offering.[56]

---

[52] Hearing Exhibit 22, Joint Proposal, Appendix W lists all EAM targets and incentives.

[53] See Hearing Exhibit 22, Joint Proposal, p. 34.

[54] Id., §XXII.

[55] Following the development of a technology agnostic DER or mass market default rate or a rate that is specifically intended to mitigate the rate impact of geothermal heat pump systems, no further rate impact credit will be paid out. Such a rate is expected to be developed in Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources.

[56] Insights+ is an offering provided on the CenHub Platform that allows customers the ability to enroll in a voluntary, subscription-based service that introduces enhancements to the current Insights experience. The program includes replacement of the customer's existing house meter with an Insights+ meter, enabling the customer to view hourly usage data.

Platform Service Revenues and Demonstration Projects[57]

Central Hudson's online self-service platform, CenHub, was developed by the Company as a REV demonstration project. On April 3, 2016, the CenHub Platform was made available to Central Hudson's customers and, as of December 31, 2017, 42% of Central Hudson's customers have engaged with the CenHub Platform. Upon issuance of this order, CenHub will no longer be considered a demonstration project, but rather will be funded through base rates, with the Platform Service Revenues (PSRs) it generates shared 80/20 between customers and the Company.[58]

Insights+ is an offering provided on the CenHub Platform. It has not been available to customers long enough to assess the value that it can provide to customers. As a result, it will continue as a demonstration project.

Miscellaneous Provisions

Among other provisions of the JP are the following:

1) Acknowledgement that JP terms may be subject to update arising out of generic Commission proceedings, including but not limited to (i) the REV Proceeding; (ii) Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources; (iii) Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative; and (iv) Case 17-M-0815, Proceeding on Motion of the Commission on Changes in Law that May Affect Rates;[59] and

---

[57] Hearing Exhibit 22, Joint Proposal, §XXIV.

[58] This PSR will be excluded from the calculation of the Company's regulatory earnings.

[59] Hearing Exhibit 22, Joint Proposal, §XXV.A.

2) A proposed process for how disputes regarding the interpretation of the JP or implementation of any of the provisions of the JP should be resolved.[60]

DISCUSSION

Based on our review of the JP and the evidence and arguments supplied by its proponents, we conclude that the JP meets the criteria set forth in the Commission's Settlement Guidelines,[61] such that its terms should be adopted and incorporated into a rate plan for Central Hudson for the next three years. We find that all procedural protections were afforded to all participants in the case, such that the parties had full notice and opportunity to make their views known in both the litigated and settlement tracks of the proceeding. The JP that has resulted from the settlement negotiations reflects compromises made by diverse and ordinarily adversarial parties with strong incentives to craft resolutions that addressed their various interests. It is a proposal that could reasonably be expected to result from litigation. However, as a rate plan developed by so many parties with specialized knowledge, we conclude that it is likely superior to the probable outcome of adversarial litigation. We find that the proposed rate plan reflects an appropriate balancing of ratepayer and shareholder interests, such that the rate increases are close to the minimum necessary to provide the Company with a fair return on its investment while enabling it to provide safe and adequate service and advance important State policy objectives. As such,

---

60 Id., §XXV.F.

61 Cases 90-M-0255, et al., Procedures for Settlements and Stipulation Agreements, Opinion 92-2 (issued March 24, 1992) (Settlement Guidelines).

the resulting rates are just and reasonable, and in the public interest.

We find much in the JP that is laudable, and we highlight some of its more salient provisions below.

Revenue Increases/Term

We find that the three-year term of the rate plan is in the public interest because it provides customers and the Company with long-term delivery rate certainty and greater stability and ability to plan than would be possible in a one-year litigated case. The three-year term is described by MI as "a sweet spot" that provides the utility with increased revenue certainty and the ability to focus on operating as efficiently as possible without repeated forays into the rate-setting process, provides customers increased rate certainty, and allows utilities, customers, and regulators with the opportunity to avoid annual rate case litigation. Instead, it affords parties the ability to resolve certain issues creatively, in ways not often possible through litigation, including moderating near-term rate impacts over a longer period.[62] The three-year term agreed to in this JP indeed provides the benefits highlighted by MI. In addition, we note that an added benefit of three years is that it is long enough to justify the extensive commitment of time and resources that is required to craft such a comprehensive proposal but still short enough to likely avoid the greater risks of inaccuracy that would accompany the forecasts and projections that would have to be used in a longer-term plan.

The recommended $19.725 million electric delivery revenue increase for Rate Year 1 is substantially lower than the

[62] Statement of Multiple Intervenors in Support of JP (MI Statement), pp. 4-5.

Company's corrected and updated requested Rate Year 1 increase of $66.2 million. The electric revenue increases are driven mainly by increased capital investments and depreciation expense, the change from collecting $8.5 million of energy efficiency costs through base rates instead of via a surcharge, right-of-way maintenance (transmission and distribution), and information technology.

The recommended $6.7 million gas delivery revenue increase for Rate Year 1 is much lower than the Company's requested Rate Year 1 increase of $22.2 million. The gas delivery revenue increases are driven mainly by increased capital investments and depreciation expense, and increases in operational and maintenance expenses related to funding low income programs, the change from collecting $0.8 million of energy efficiency costs through base rates instead of via a surcharge, information technology, and site investigation and remediation costs.

The proposed electric and gas increases reflect adjustments to and compromises from the parties' litigation positions, including compromises between Staff and the Company on items such as the overall electric revenue and gas revenue levels, use of regulatory liabilities as moderators, and the recommended ROE and common equity ratios. MI views the electric and gas revenue requirements, the reflection of anticipated federal tax savings in those revenue requirements, the use of rate moderators and energy efficiency program cost recovery, among others, as some of the most important issues resolved by this JP.[63] UIU likewise highlights the beneficial impact that concessions by the Company on its requested ROE and equity ratio had on the revenue requirement levels. CLP notes that it argued against a rate increase and the JP proposes more modest increases.[64]

Staff states that the rate increases provided for under the JP are necessary to allow the Company to continue to provide safe, reliable, and affordable service and are driven, on the electric side, by increased capital spending and related depreciation expense and the transfer of energy efficiency expenses currently collected through a surcharge into base rates. Staff adds that while these drivers are not unique to Central Hudson, they are subject to inevitable increase and are difficult to control. We agree with Staff that the revenue levels agreed to in this JP are necessary to ensure that the Company has sufficient funding to provide safe and adequate service at just and reasonable rates. We find the revenue levels to be reasonable, especially in light of the Company's acknowledgement that the JP's lowered revenue requirements results in a rate plan that ensures it has adequate resources to fulfill its statutory obligation to provide safe, adequate, and reliable service, including providing the funding to increase

---

63 MI Statement, pp. 2, 4. MI notes that the electric service classes most relevant to it are (1) SC 3 (Large Power Primary Service) and (2) SC 13 (Large Power Substation and Transmission Service), while the gas service classes most relevant to its interests are (1) SC 9 (Interruptible Transportation Rate) and (2) SC 11 (Firm Transportation Rate – Core, subclasses (a) Transmission and (b) Distribution). The other issues that MI views as among the most important resolved by the JP signatories include the electric and gas revenue allocations and the electric and gas rate designs applicable to large nonresidential customers. Id., p. 2.

64 Citizens for Local Power Statement on the Joint Proposal (CLP Statement), p. 3.

employee numbers to better serve its customers and handle increasing business complexities, modernize the electric and gas infrastructure, and enhance the Company's IT systems.[65]

We note that the proposed rate increases have been significantly mitigated because of lower federal income tax expense resulting from the recently enacted Tax Act, lower employee pension and OPEB costs because of pension fund gains and a change in accounting, and a decreased overall rate of return and other changes to rate base and have been moderated by the application of credits. Indeed, in support of the revenue requirements that are advocated in the JP, MI credits the "fortuitous timing of a substantial federal income tax reduction and the availability of tens of millions of dollars in regulatory liabilities (*i.e.*, deferred customer credits) for use as rate moderators" for helping to get the increases to a level that it could support, rather than oppose.[66] The Company, Staff, and MI acknowledge that the revenue requirement amounts set forth in the JP reflect material estimated federal income tax

---

[65] Statement of Central Hudson Gas & Electric Corporation in Support of Joint Proposal (Company Statement), pp. 8-9, 11.

[66] MI Statement, p. 7. While MI supports the JP revenues requirements, it urges the Commission to reevaluate some of its policies and priorities and thereby help to "stem the tide of significant utility delivery rate increases that are threatening the ability of businesses and industries to remain competitive in New York State." MI Statement, pp. 5-6; see also MI Statement, p. 8.

reductions,[67] which they and others agreed to allocate 100% to customers, as fair, equitable, and in the public interest. MI adds that the capture of 100% of the estimated Tax Act savings for the benefit of customers in the form of lower delivery rates starting in Rate Year 1 was very important and indeed contributed to its decision to execute and support the JP.[68]

With respect to the proposed use of credits, we note that, by adopting Staff's recommendation to spread the regulatory credits over a three-year period instead of the Company's litigation recommendation to use all the credits to offset Rate Year 1 increases, the JP will provide rate mitigation both during and after the term of the rate plan.[69] The agreement regarding the use of credits garnered widespread support among the Signatory Parties. MI says that it strongly supported the negotiated return of $34.5 million of regulatory

---

67 The JP proposes that the Company be "held harmless for any changes it is required to make due to the [Tax Act] and/or any state or local action resulting from the [Tax Act] and is authorized to defer the revenue requirement of any changes it is required to make due to the [Tax Act]." JP, p. 26. At the hearing, the Company explained that, due to time constraints, the parties had been able only to estimate the financial effects the Tax Act would have on the Company and the associated amounts to be allocated to the ratepayers. As such, the Company explained, the term "held harmless" was included in the JP to clarify that the Company would be able to defer the revenue requirement impacts not directly related to the Tax Act or other impacts that were unknown at the time the JP was executed. Evidentiary Hearing Transcript (Tr.), pp. 17-28.

68 MI Statement, pp. 9-12.

69 Staff acknowledges that the use of a bill credit to moderate electric rates in Rate Year 3 will force a small rate increase at the end of the Rate Plan's three-year term, but says that the impact is minimal and the rate moderators proposed under the JP do not use all projected available net regulatory liabilities, thus leaving a portion available for future offset use. Staff Statement, pp. 21-23.

liabilities to electric and gas customers, adding that the amounts settled upon provide substantial moderation of what otherwise would be considerably higher delivery rate impacts.[70] UIU similarly touts the proposed use of credits when it observes that the JP further cushions customer impacts by (1) spreading the revenue recovery over a three-year period and (2) allocating electric and gas bill credits to each service class as rate moderators, both of which help soften customer rate shock. Moreover, UIU adds that it supports the Company's passing back customer credits in a timely manner while reserving some customer credits to help mitigate future rate increase.[71] The JP's approach to the use of bill credits is another one of several of its recommendations that are evidence of a result that falls within a range of reasonable litigated outcomes and is supported by record evidence.

Almost all the public comments received in these proceedings voiced opposition to any rate increases. However, we find that the increases recommended in the JP are necessary as they provide sufficient revenues to allow Central Hudson to maintain and improve the provision of safe and reliable electric and gas service, at just and reasonable rates. Among other things, increases are needed to allow the Company to maintain and upgrade its electric and gas infrastructure and information systems, fund additional energy efficiency expenses, and significantly expand its low income customer discount programs. The use of customer credits to offset the increases will moderate the delivery rate impacts, providing some measure of rate relief for all customers. With such offsets, the total monthly bill for a typical residential customer will increase,

---

70 MI Statement, pp. 12-13.

71 Utility Intervention Unit Statement in Support of the Joint Proposal (UIU Statement), pp. 3-4.

on average, by $1.46 (or 1.3%) for electric service and $2.54 (or 2.1%) for gas heating service in Rate Year 1. In addition, the numerous reconciliation provisions, along with the earnings sharing mechanism, will protect ratepayers to the extent there are variances between the estimated costs that comprise the revenue requirement and the Company's actual expenditures.

Staff was the only party to present a case in support of alternative overall revenue requirements. Ultimately the parties that engaged in the extensive negotiations that led to this JP agreed to the amount of the proposed increases that we are now approving. We find that the results of those negotiations are in the public interest and fall within the reasonable range of outcomes likely to result from litigation.

Cost of Capital

For Rate Year 1, the JP establishes rates based on a return on equity of 8.8% and a 48% common equity ratio for both Central Hudson's electric and gas businesses. The common equity ratio increases to 49% in Rate Year 2 and 50% in Rate Year 3. The foregoing provides the Company with an overall after-tax cost of capital of 6.44% in Rate Year 1, 6.49% in Rate Year 2, and 6.54% in Rate Year 3.

In its litigated case, Central Hudson initially sought a 9.5% ROE, which its ROE witness described as the low end of a 9.48% to 10.15% range of reasonableness.[72] The Company's witness derived her range of results by employing combinations of her low, mean and high Discount Cash Flow (DCF) analyses with her Capital Asset Pricing Model (CAPM) analyses and either weighting the two methodologies equally or two-thirds DCF to one-third

[72] Hearing Exhibit 1, Pre-filed direct testimony of Company Witness Buckley, p. 5.

CAPM.[73] The Company also requested a 50% common equity ratio.[74] In contrast, Staff's litigated position supported an 8.3% ROE.[75] Staff's position was rooted in the Commission's traditional weighting of two-thirds DCF to one-third CAPM results recently reaffirmed in our 2018 rate order for Niagara Mohawk Power Corporation.[76] Staff recommended a 48% common equity ratio.[77]

Central Hudson, MI, UIU, and Staff note that the proposed ROE and common equity ratios reflect a balancing of the concessions made by the Signatory Parties in the context of the financial and economic circumstances anticipated for Central Hudson during the JP's term.[78] UIU, for example, notes that the reduction in ROE from 9% to 8.8% reduces the electric and gas revenue requirements each of the three rate years, thus benefitting customers. In its support of the proposed 8.8% ROE and the increasing common equity ratios, Staff notes that these

---

[73] Id., pp. 3-5.

[74] Id., p. 90.

[75] Hearing Exhibit 16, Pre-filed direct testimony of Staff Finance Panel, pp. 9-10.

[76] See Case 17-E-0238 and 17-G-0239, Niagara Mohawk Power Corporation – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 15, 2018), p. 37 (2018 Niagara Mohawk Rate Order).

[77] Hearing Exhibit 16, Pre-filed direct testimony of Staff Finance Panel, pp. 9-10.

[78] See, e.g., Company Statement, pp. 21-22; MI Statement, pp. 7-8; Staff Statement, p. 42; and UIU Statement, pp. 3-4. Central Hudson and UIU, for example, note that the Company's concessions regarding the reductions in its requested ROE (moving from 9.5% to 8.8%) and equity ratio (50% to 48% in Rate Year 1 and 49% in Rate Year 2) helped to reduce the electric and gas revenue requirements, while MI notes that its compromise on equity ratio should not be read as an intent to modify, or signal any movement away from, the Commission's longstanding practice of capping a utility's equity ratio for ratemaking purposes at 48% absent extenuating circumstances.

terms adequately recognize the increased financial risk and business risk that are inherent when setting rates over a multi-year period and the higher interest rate environment since its 8.3% recommended ROE determination.[79] These terms also recognize the pressure on the Company's financial metrics attributable to the Tax Act.

Regarding the 50 basis point difference between its 8.3% ROE recommendation and the JP's 8.8% ROE, Staff explained that, "as opposed to a single-year rate decision, the extended term of the JP inherently carries more financial risk as investors are subject to additional risk economic conditions will change and the actual cost of capital will increase during the three-year interim."[80] Staff adds that "because the JP also locks in forecasted amounts for numerous elements of expense for the three-year term of the JP, Central Hudson's business risk is also impacted by the potential that actual operating costs turn out to be greater than those forecasted."[81]

Staff also represents that current economic conditions indicate that the Commission's preferred ROE methodology would produce a higher ROE than the 8.3% ROE it recommended using data through September 2017. It notes that in September 2017, the yield requirements on 10-year and 30-year U.S. treasuries were 2.31% and 2.87%, respectively. When the JP was signed on April 18, 2018, those same yields had increased to 2.87% and 3.06%.[82]

In the most recent National Fuel Gas Distribution Company (NFG) rate order, the Commission reaffirmed the

---

[79] Staff Statement, p. 40.

[80] Id., p. 41.

[81] Id., pp. 41-42.

[82] Id., p. 40.

principles underlying our long-standing methodology for calculating a reasonable return on equity for a rate plan, regardless of whether it is ordered on a settlement or litigated track.[83] Those elements consist of the application of DCF and CAPM analyses to a representative proxy group of utility companies; the use of a two-stage DCF computation with inputs derived from Value Line; the basing of CAPM results on an average of the outcome from standard and zero-beta models with a risk-free rate based on Treasury bonds, market risk premium provided by Merrill Lynch's Quantitative Profiles, and betas taken from Value Line; and the use of a 2/3 – 1/3 weighting of the DCF and CAPM results, respectively.[84]

We agree with Staff that that a return on equity that is higher than the one produced by our preferred methodology is reasonable in this case considering the added financial and business risk accepted by Central Hudson. Specifically, we find the JP's 8.8% ROE is reasonable as it is based on the application of our cost of equity methodology plus a rational premium to compensate investors for the additional risk that economic conditions could increase the cost of capital during the three-year rate plan as well as for the possibility that actual operating costs turn out to be greater than those forecasted by the JP. With respect to increases in the cost of capital, we note that an update of our preferred methodology is now 8.6%. This is evidence of the very real financial risk being borne by the Company as the soonest its rates may be adjusted to reflect increases in the cost of capital is July 1, 2021.

83 Case 16-G-0257, National Fuel Gas Distribution Corporation – Rates, Order Establishing Rates for Gas Service (issued April 20, 2017), pp. 53, 57 (2017 NFG Rate Order).

84 Id., pp. 52-53.

We also find the ESM included in the JP to be reasonable. As we have previously stated, such mechanisms give the utility an incentive to cut costs during the rate plan. If the savings achieved are significant enough, customers will benefit during the rate plan. The higher sharing percentages as the ROE increases provide an important protection for customers against forecasted cost errors, especially in the later years of the rate plan. When rates are reset, customers will capture the full benefit of the cost-cutting going forward.

Turning to the 49% Rate Year 2 and 50% Rate Year 3 common equity ratios, Central Hudson and Staff state that the specific intent is to provide the Company with a reasonable opportunity to maintain its credit ratings within the "A" categories of the major credit ratings agencies.[85] In testimony, Central Hudson argued that a 50% common equity ratio was needed for it to be upgraded to an "A" rating from Standard & Poor's while Staff argued that increasing the Company's authorized common equity ratio from 48% to 50% was neither necessary or cost-effective. Subsequently, on December 22, 2017, the Tax Act was signed into law. For utilities, the cash flow ramifications that result from the Tax Act's provisions are largely viewed negatively by the major credit ratings agencies and according to the JP, the compromise common equity ratios contained in the JP acknowledge the change in Central Hudson's creditworthiness associated with the Tax Act.

According to Staff, the JP's use of a greater equity cushion over the next several years is warranted because the modest cost incurred to strengthen Central Hudson's balance sheet, and thereby materially enhance the Company's critical cash flow metrics, is a reasonable tradeoff considering the

[85] Company Statement, pp. 21-22; Staff Statement, pp. 40-41.

potential costs to ratepayers should the Company's credit ratings fall out of the "A" ratings categories.[86] Central Hudson opines that the proposed equity ratios reflect a reasonable compromise between the litigated positions of it and Staff.[87]

Given the degree of uncertainty regarding the ultimate impact of the Tax Act on the Company's creditworthiness, we find the JP's use of higher common equity ratios in Rate Year 2 and Rate Year 3 to be a responsible and reasonable measure to forestall, or at least diminish, the prospect of higher future borrowing costs attributable to a diminution in Central Hudson's creditworthiness over the next several years. As Staff points out, the Company could face higher borrowing costs of approximately $5 to $10 million on a net present value basis with a one-notch downgrade, while the added cost of the thicker common equity layer, in terms of revenue requirement, is about $1 million in Rate Year 1 and $2 million in Rate Year 2.[88] In sum, while each utility will have different circumstances, the parties to this JP have adequately demonstrated the reasonableness of bolstering Central Hudson's ratemaking common equity ratio in the short run during the rate plan to counter the near-term negative impacts of the Tax Act.

IT Upgrades

The JP includes enhancements to the Company's IT that will allow it to modernize its systems and meet increasing customer, regulatory, and business demands. One such project is the planned modernization of the Company's Customer Information System (CIS), which is more than 35 years old. The pursuit of this project is consistent with the high priority placed on IT

86 Staff Statement, p. 41.

87 Company Statement, pp. 21-22.

88 Staff Statement, p. 41.

modernization by the Commission in the most recent management audit of Central Hudson.[89]

The JP's new reporting requirements related to IT projects, set forth in JP Appendix P and summarized earlier in this order, will help to ensure accountability and transparency. We find that the provision of funding that will permit the Company to prioritize IT capital projects, especially when coupled with these new reporting requirements, is in the public interest and should be approved.

Training Center and Primary Control Center Projects

In its initial testimony, Central Hudson proposed to construct a Training Center that would allow it to educate its changing workforce in a safe and controlled environment that simulates real-life field conditions. The Company asserted that the Training Center would benefit customers by allowing Central Hudson to conduct drills with first responders; provide training on pipeline operation and maintenance in response to changes in gas safety regulations; and conduct electric progression training under simulated conditions, thereby no longer requiring the Company to take equipment out of service to conduct such training. Central Hudson contended that the Training Center's goal was to ensure that Central Hudson continues to provide safe and reliable service. The Training Center was proposed to be a multi-year, dual-phase project, estimated to cost about $32.5 million dollars, with an in-service date of January 2021.[90]

---

89 Case 16-M-0001, In the Matter of a Comprehensive Management and Operations Audit of Central Hudson Gas & Electric Corporation, Order Releasing Audit Report (issued October 24, 2017).

90 See Hearing Exhibit 1, Pre-filed testimony of Central Hudson's Training and Development Panel (TDP) and Exhibit, TDP-3.

Central Hudson also proposed to construct a new, more modern Transmission and Distribution Primary Control Center, co-located with the Training Center. The Company stated that the current control center is too small and lacks the technology needed to support the Distribution Management System, a system that will allow remote control monitoring of the electric distribution system.[91] The Company proposed to spend about $2.2 million in 2018 and $1.7 in 2019 on the Primary Control Center.[92]

In its pre-filed testimony, Staff agreed that the centers were needed, stating, among other things, that a centralized training center with classrooms equipped with computers, IT support, Internet, site security protocols, and hands-on equipment, would provide more efficient and effective training programs for Company employees and contractor personnel, including training capable of keeping pace with the increased training requirements for pipeline operation and maintenance. Staff stated that, since the proposed Training Center would provide value to ratepayers, the provision of training at the proposed facility to both Company personnel and non-Company personnel (e.g., qualified contractors performing work for the utility and first responders) is appropriately ratepayer funded.

Staff asserted that the need for additional training could reasonably be expected as requirements pertaining to work performed on electric and gas facilities are expected to be expanded in the near term. However, given its concerns that the Company had not yet purchased land or finalized the permitting process, Staff stated that the Company's proposed timeline was

---

91 See Hearing Exhibit 1, Pre-filed Testimony of Central Hudson's Distributed System Platform Panel.

92 See Hearing Exhibit 1, Pre-filed Exhibits of Central Hudson's Training and Development Panel, TDP-3.

too aggressive and the scope and final cost of the Training Center might be excessive. With respect to the proposed Primary Control Center, Staff noted that under the Company's proposed timeline, it would not be in service until 2021. As a result, Staff recommended that the Company meet with Staff quarterly regarding both Projects; file annual progress reports on both Projects with the Commission; and not be given full symmetrical deferral of all Primary Control Center expense items. Staff also recommended the disallowance of proposed 2018 and 2019 capital budget amounts associated with the Primary Control Center.[93]

As noted in the summary of the JP, *supra*, the Joint Proposal outlines a process that requires the Company to provide information about the scope of and timeline for the Projects, and then provide periodic major milestone reports thereafter. Under the JP, the Company would be allowed to develop the Projects, subject to approval, delay, or cancellation of such deployment and implementation by either the Director of the Office of Electric, Gas, and Water or by the Commission.

The Company and Staff have persuasively demonstrated, due to emerging technologies and changing safety standards and workforce, that the Company needs a centralized approach to training that offers hands-on and scenario-based training opportunities for Central Hudson employees, outside contractors (such as tree trimming contractors and LPP contractors), municipal agencies (e.g., Department of Public Works, first responders, etc.) and mutual aid crews, to ensure that the Company continues to provide customers with safe and reliable service. They also have convincingly established that the

---

93 Hearing Exhibit 16, Pre-filed Testimony of Staff Training Panel, pp. 13-15.

Primary Control Center will ensure that Central Hudson retains the ability to monitor and control its distribution system.

We find that the process outlined in the JP, with one additional requirement, will facilitate the development of the proposed Training Center and Primary Control Center and a utility workforce with necessary skills to consistently, efficiently, and effectively construct and maintain the safety, adequacy, and reliability of the electric and gas facilities and systems used to provide electric and gas service to Central Hudson customers. While the JP requires Staff and the Company to meet and discuss the major performance milestones timeline within 60 days of the filing of the Initial Report and provides for a Commission ruling if mutual agreement cannot be reached, the Company is hereby not authorized to make any capital expenditures on the Training Center and Primary Control Center prior to receiving approval of the Initial Report and major performance milestones timeline from the Director of the Office of Electric, Gas, and Water, upon consultation with the Commissioners at the direction of the Chair. We also caution that the Training Center should be dedicated to the betterment of the workforce and be designed for the necessary functions the workforce performs and not for unnecessary or duplicative objectives that could be reasonably performed elsewhere. In addition, we note that one near-term focus should be on improving and meeting operator qualifications and meeting gas safety requirements. By defining the scope, major performance milestones, and associated checkpoints; allowing for the establishment of a specific time for meeting clear, readily measured indicators that show functional capabilities as well as operational integration; and defining a method to implement and document the Projects' checkpoint compliance, review, and approval process, the process supports careful and considered planning by the Company and ensures periodic review by the Staff. By expressly making the continuation of the Projects' development and implementation subject to potential alteration or cancellation by the Director of the Office of Electric, Gas, and Water, in consultation with the Commissioners at the direction of the Chair, or by the Commission itself, the process we are approving should help ensure that the concerns about the cost and scope of the centers are appropriately balanced against need for training and for a qualified and capable utility workforce.[94] Moreover, by this Order, we are limiting the amount of plant in service for the Projects to the proposed $5 million. Any additional amounts will be authorized only by future Commission approval. With these additional requirements, the gradual and considered development of these Projects as outlined in the JP reflects a reasonable compromise and is in the public interest.

Low Income Programs

Changes to the Company's current Low Income Program, called the Enhanced Powerful Opportunity Program (EPOP), are required to satisfy program modifications established in the Commission's generic low income proceeding.[95] The Low Income Order established a policy to limit energy costs for low income households to no more than six percent of household income and adopted a default methodology for setting tiered discount levels

---

[94] It is our understanding that the Rate Year 2 and Rate Year 3 revenue requirements include a total of $5 million in funding for the development of the proposed centers. The Company and Staff testified that this amount reflects the levels of plant in service assumed in the Rate Year 2 and Rate Year 3 revenue requirements, adding that this amount is intended to fund the acquisition of land and the construction of the proposed gas village. Tr. 38-39.

[95] Case 14-M-0565, supra, Low Income Order and Low Income Rehearing Order.

that vary based on the level of need. The Low Income Order also established a funding limit such that the utility's total budget may not exceed two percent of total electric or gas revenues for sales to end-use customers. Pursuant to the Low Income Order, on September 16, 2016, Central Hudson filed a Low Income Program Implementation Plan with the Commission, which approved the plan with modifications on February 17, 2017.[96]

The Company's current EPOP has three components: a bill discount, arrears forgiveness, and a reconnection fee waiver. The Company's initial testimony indicated that it stopped accepting enrollments into EPOP on April 15, 2017, and, beginning on or about November 15, 2017, EPOP would be replaced with its new Low Income Bill Discount Program in accordance with the Implementation Plan, as modified by the Implementation Order. Low income customers are eligible for the Low Income Bill Discount Program if they receive HEAP benefits for their electric, gas, or other fuel services. The new Low Income Bill Discount Program will have the following components: monthly low income bill discounts; automatic enrollment in Budget Billing, with an opt-out option; and reconnection fee waivers.

The JP proposes significant incremental funding for the new Low Income Bill Discount Program: $8.612 million in Rate Year 1 ($5.727 million for electric and $2.885 million for gas); $11.015 million in Rate Year 2 ($7.325 million for electric and $3.690 million for gas); and $12.018 million in Rate Year 3 ($7.992 million for electric and $4.026 million for gas). These funding levels will result in bill discounts for electric heating and non-heat customers of between $19 and $39 per month, gas heating customers of between $30 and $50 per

---

[96] Case 14-M-0565, supra, Order Approving Implementation Plans with Modifications (issued February 17, 2017) (Implementation Order).

month, and gas non-heating customers of $3 per month.[97] These discounts are much greater than the current monthly discounts of $5.50 for non-heating gas and non-heating electric customers, $17.50 for electric heating customers, $5.50 for gas heating customers, $23 for heating customers utilizing both electric and gas, and $11 for non-heating customers utilizing both electric and gas.[98]

The Company will phase out the arrears forgiveness aspect of EPOP during Rate Year 2. However, Central Hudson will maintain the arrears forgiveness component of the EPOP program for customers who were EPOP participants for so long as they continue to qualify for the program and/or until they have completed the arrears forgiveness component. Given that the arrears forgiveness program under EPOP provided a benefit for 36 months, the last EPOP customer is expected to exit the program in or about March 2020. The total costs associated with the arrears forgiveness component of EPOP are forecasted to be $142,000 in Rate Year 1 and $6,000 in Rate Year 2. These amounts fall well under the amount approved in the Implementation Order, which was $260,482 per year.

The Low Income Order provides utilities with the option to charge or waive reconnection fees for low income customers. The JP proposes continuing Central Hudson's Reconnection Fee Waiver Program, with an increased allowance of

---

97 Hearing Exhibit 1, Pre-filed direct testimony of Central Hudson's Low Income Panel, p. 7, Table 1. The discounts will be calculated according to the eligibility criteria described in the Low Income Order. Hearing Exhibit 16, Pre-filed direct testimony of Staff's Consumer Policy Panel, p. 16.

98 Hearing Exhibit 16, Pre-filed direct testimony of Staff's Consumer Policy Panel, p. 9.

$51,000 for each Rate Year.[99] This funding level is within the permissible budget total established in the Low Income Order, and will permit the Company to offer eligible low income customers a one-time waiver of the reconnection fee.[100]

The JP proposes that the Company will defer Low Income Bill Discount program costs in excess of the proposed amounts for future recovery from ratepayers, as authorized by the Low Income Order, and it will defer under-expenditures for future use to support low income programs. Symmetrical deferred accounting is proposed for costs associated with the arrears forgiveness phase-out and the Reconnection Fee Waiver Program. In addition, the Low Income Bill Discount Program will undergo annual adjustments to account for changes in enrollment projections, average bill amounts, and State Median Income levels that underlie HEAP income eligibility limits.

Finally, the JP requires the Company to update and improve its customer service Integrated Voice Response (IVR) messaging system to include information about the new Low Income Program, including the availability of and requirements for eligibility for the program.[101]

The Company states that the proposed Low Income Program is consistent with the Low Income Order and will serve nearly 25,000 customers by the end of Rate Year 3. It states that the provision for the automatic enrollment of eligible customers in the Budget Billing Program serves the public interest by offering those customers levelized bills. The

---

[99] Current allowance for this program is $35,000 annually. Id., p. 22.

[100] The Company's reconnection fees currently range from $20 to $100. Hearing Exhibit 1, Pre-filed direct testimony of Central Hudson's Low Income Panel, p. 12.

[101] Hearing Exhibit 22, Joint Proposal, p. 59.

Company believes that the levelized bills will protect those customers from the rate shock associated with price spikes resulting from periods of high energy consumption. In addition, the Company believes that the proposed enhancements to its IVR system will provide customers with greater transparency regarding payment options, which will reduce the number of service terminations for customers in arrears. The Company adds that the planned phase-out of the arrears forgiveness program is reasonable given the overall increase in funding and customer outreach associated with the new Low Income program.

Staff comments that the funding levels for the new Low Income Program will provide eligible low income customers with reductions in their monthly bills of between 17% and 65%.[102] Staff reports that the Signatory Parties all agreed that the Company should replace its existing low income customer program with the proposed new program. According to Staff, the new Low Income Program complies with the Implementation Order, and the annual rate allowances comply with Commission directives to cap the budget for the program at 2% of sales revenue.

PULP adds that it supports this new Low Income Program given that the program will serve more customers and receive greater funding than the previous program and, thus, better serve the public interest.[103]

We agree that the JP's proposal to implement the new Low Income Discount Program as approved by the Implementation Order is reasonable. It is estimated that Central Hudson's new Low Income Program ultimately will serve nearly 25,000 customers, which is approximately three times the number of customers currently being served under the EPOP. We previously

---

[102] Staff Statement, p. 9.

[103] PULP Statement in Support of JP, pp. 6-7.

have recognized there is a significant energy "affordability gap,"[104] and the proposed program considers the projected increased customer participation and discount levels sufficient for participating customers to keep their energy burden at or below 6% of the household income. Central Hudson's new Low Income Program follows the structure for low income programs established in the Low Income Order and Rehearing Order, which resulted from an extensive process designed to carefully balance the interests of low income customers, other customers, and the utilities.

Vegetation Management

Generally, the purpose of funding for Central Hudson's vegetation management programs is to minimize customer outages caused by trees and tree limbs coming into contact with overhead power lines. The Company's transmission right-of-way (ROW) vegetation management program consists of routine ROW maintenance, including vegetation trimming, danger tree removal, and ROW edge reclamation. The Company's main distribution ROW maintenance activity is scheduled on- and off-road line clearance, which work is performed on a four-year cycle. The JP proposes funding levels for Central Hudson's ROW maintenance programs for both transmission and distribution lines that are increased above those levels established in the prior rate order.

In its initial filing, the Company proposed a distribution ROW vegetation management program budget of $25.57 million for Rate Year 1, which included $11.50 million in incremental funding for its line clearance cycle, reinstatement of the Enhanced Line Clearance Program, and a new activity to mitigate the impacts of the Emerald Ash Borer. Staff agreed

[104] Low Income Order, supra, pp. 4, 8.

with the Company that the Emerald Ash Borer was causing unprecedented tree-related risks. Staff nevertheless recommended downward adjustments to aspects of the Company's proposed distribution ROW vegetation management program, resulting in a recommended rate allowance of $19.59 million in Rate Year 1. Staff specifically recommended that the Enhanced Line Clearance Program not be allocated any funds since, if the work proposed under the other aspects of the Company's ROW maintenance programs were completed, reliability performance gains comparable to those proposed in the Enhanced Line Clearance Program would be achieved.[105]

The JP follows Staff's recommendations for funding the Company's distribution line ROW clearance program at $19.59 million in Rate Year 1, $20.00 million in Rate Year 2, and $20.419 million in Rate Year 3, for a total of $60.01 million.[106] The variance between the figures proposed in the JP and the Company's initial request is due to the elimination of the proposed incremental line clearance miles associated with the Company's on- and off-road line clearance and the re-funding of the Enhanced Line Clearance Program.

As for its transmission ROW vegetation management program, the Company initially proposed a budget of $2.45 million for Rate Year 1. The Company later filed supplemental testimony proposing to increase the Rate Year request to $4.77

---

[105] Hearing Exhibit 16, Pre-filed direct testimony of Staff's Vegetation Management Panel, pp. 25-27.

[106] Hearing Exhibit 22, Joint Proposal, Appendix A, Schedule 1.

million, an increase of approximately $2.3 million.[107] Central Hudson claimed that the increased request related to its need to perform work that was not completed within the 2015 Rate Plan budget. Staff recommended downward adjustments to Central Hudson's transmission ROW maintenance budget to $2.25 million.[108] In rebuttal, the Company proposed $3.5 million to address time-sensitive backlog work.

The JP proposes to accept the Company's figure offered in rebuttal for Rate Year 1, and proposes $2.9 million in Rate Year 2 and $2.61 million in Rate Year 3.

Finally, the JP proposes that the allowances now will be subject to an annual reconciliation, which will permit the Company to have more flexibility by allowing specified dollar amounts to be used as necessary in different Rate Years.[109] Specifically, the JP proposes that the Company may defer funds from under-spending on vegetation management in Rate Year 1 for use in Rate Year 2 and from under-spending in Rate Year 2 for use in Rate Year 3. For distribution ROW vegetation management,

---

[107] See Case 17-E-0250, Petition of Central Hudson, Order Denying, in Part, Deferral Accounting and Recovery of Additional Distribution and Transmission Vegetation Management Funds and Relief from the 2016 Frequency Performance Metric (issued September 18, 2017). Central Hudson had petitioned the Commission for additional funding to implement a targeted distribution danger tree program, as well as additional funding for transmission ROW maintenance. The Commission denied the Company's request for an additional $1.9 million in incremental funding for transmission ROW maintenance, finding that, unlike with distribution ROW maintenance, which had been affected by the rapid migration of the Emerald Ash Borer, there were no unforeseen circumstances that affected the Company's transmission ROW maintenance.

[108] Hearing Exhibit 16, Pre-filed direct testimony of Staff's Vegetation Management Panel, pp. 8-14.

[109] Hearing Exhibit 22, Joint Proposal, p. 18.

the amount that can be deferred is capped at $1 million, and for distribution ROW maintenance the amount is capped at $500,000. In Rate Year 3, if the Company underspends the Rate Year 3 allowance and any other previously deferred funds, all the underspent funds will be deferred for ratepayer benefit.

Similarly, the Company may defer overspending from one rate year to the next, thereby reducing the next rate year allowance. The same deferral caps are applicable. If Central Hudson overspends in Rate Year 3, all overspending will be absorbed by the Company, with no deferral.

The Company says that the reconciliation method proposed in the JP will provide it with flexibility between Rate Years, but also provides ratepayers with protection by proposing a downward-only deferral mechanism at the end of Rate Year 3. The Company explains that this asymmetrical deferral will benefit customers by safeguarding them from any overspending by the Company and prevent the Company from benefitting if it underspends.

Staff says that the vegetation management funding levels proposed in the JP will allow Central Hudson to improve reliability by reducing tree-related outages on distribution and transmission lines. Staff agrees with the Company that the Emerald Ash Borer is causing significant tree-related risks and that the Company must proactively address the threat.

An aggressive vegetation management program designed to decrease tree-related outages and thereby improve reliability is of critical importance. The funding levels proposed in the JP strike a fair compromise between the respective budgets initially proposed by the Company and Staff. The Commission recognizes the effect the Emerald Ash Borer and other invasive species have on trees within Central Hudson’s territory and believes that the level of funding provided for in the JP, as well as the new policy permitting annual reconciliation, will provide the Company with the necessary funds and flexibility to effectively implement its vegetation management programs, thereby preserving electric system reliability for customers.

Geothermal Rate Impact Credit

The JP proposes that, within its Carbon Reduction Program (CRP), Central Hudson will develop a Geothermal Rate Impact Credit program in collaboration with NYSERDA. The rate impact credit, which is proposed to be $264, would be paid to participating residential customers annually, by June 30 of each year. The credit was calculated by comparing the additional delivery revenue that the Company would receive from the incremental energy use during the heating season of the geothermal heat pump under the current rate design, to what those revenues would be under a more cost reflective rate design. This difference, for an averaged size geothermal system in the Company's territory results in $264. In order to qualify for the credit, customers must install equipment that meets the requirements of NYSERDA's Geothermal Rebate Program. In addition, the JP proposes that the participating customer be required to enroll in Central Hudson's Insights+ program.[110]

The JP proposes funding the Geothermal Rate Impact Credit through an expense component of the electric RDM. Specifically, Geothermal Rate Impact Credits paid to customers

[110] Insights+ is a subscription-based, demonstration project that Central Hudson began offering on its CenHub Platform in June 2017. Central Hudson currently offers the subscription at a subsidized cost of $4.00/month. The subsidization will end once Insights+ no longer qualifies as a demonstration project. However, since Insights+ has not been available for a sufficient period-of-time to evaluate its value to customers, the program will remain a demonstration project following the issuance of this Order. Hearing Exhibit 22, Joint Proposal, pp. 73, 75.

taking service under SCs 1 and 6 will be subtracted from Actual Delivery revenue in the month that they are incurred prior to the monthly comparison of Actual Delivery Revenue to the Delivery Revenue Target.[111] The JP further proposes that, while the rate impact credit will not be included in the CRP funding cap, any necessary customer outreach, education, or implementation funding will be included.

The Company states that this proposal is in the public interest as it promotes geothermal systems, which are both environmentally and customer-friendly in that they are emissions-free and energy-efficient systems.

NY-GEO, CLP, and Bob Wyman also all generally support the Geothermal Rate Impact Credit and consider it a step forward in helping ratepayers adopt more energy-efficient alternatives to fossil fuels, thereby reducing carbon and other greenhouse gas emissions in the State.

The reduction of carbon emissions is a primary goal of New York State's Energy Policy. The Geothermal Rate Impact Credit will assist in reducing the upfront cost of investment in this energy-efficient alternative to the carbon-intensive heating and cooling methods currently utilized by many of Central Hudson's customers. In addition, by pairing the credit with NYSERDA's Geothermal Rebate Program, Central Hudson's program will assist customers in choosing and identifying quality equipment and contractors. Furthermore, funding of the credit is provided by the increased delivery revenue associated with the incremental electric usage during the heating season that the geothermal system customer will provide. This rebate recognizes the benefits that additional off-peak energy usage can provide to the system at the same time as not increasing the

[111] Hearing Exhibit 22, Joint Proposal, p. 42.

system peak and therefore costs. This program will provide encouragement to customers to adopt this emerging, environmentally beneficial technology, which, in turn, will help the customers reduce their total energy bill and, at the same time, help the State meet its ambitious energy efficiency and carbon reduction goals.

CenHub

CenHub is the Company's website and portal where customers can engage by learning about their energy consumption to help them make decisions about their usage. Beginning as a REV demonstration project, over 40% of the Company's residential customers are now enrolled in the platform and the Joint Proposal includes provisions to fund the platform through base rates. This platform will allow for the seamless provision of information, decision making and access to incentives and rebates for a host of energy efficient products and services. Overall, this platform will increase the Company's effectiveness in delivering energy efficiency programs and have a positive impact on reducing customer bills.

Energy Efficiency

Central Hudson originally proposed an ETIP annual budget, including evaluation, measurement, and verification (EM&V) and administrative costs, of approximately $8,479,345 for electric and $837,356 for gas. Staff recommended that the Company increase its annual ETIP funding for electric to $9,772,740 and for gas to $1,182,179.[112] Staff also recommended in its testimony a downward-only reconciliation of the Company's actual expenditures, to be conducted cumulatively every three years, as well as recovery of the electricity energy efficiency

---

[112] Hearing Exhibit 16, Pre-filed direct testimony of Staff Markets & Innovation and Energy Efficiency Panel, p. 12.

program costs between individual service classifications on an energy basis to ensure revenue-neutral cost allocation.[113]

The JP adopts Staff's proposed funding levels for each rate year, resulting in totals for the yearly energy efficiency budgets that are approximately 15 percent larger for electric and 40 percent larger for gas. As of July 1, 2018, these amounts will be collected in each rate year through base rates, as Staff had proposed in its testimony, rather than through the energy efficiency tracker surcharge portion of the SBC. This shift is consistent with Commission policy because it promotes a more comprehensive approach to energy efficiency, which can be combined with peak-reduction and system-efficiency activities, as cohesive components of the Company's core business.

The electric ETIP cost allocation will be based on 87.3% Energy and 12.7% Coincident Peak Demand. The gas allocation will reflect the residential (SCs 1 and 12) and non-residential (SCs 2, 6, 11 and 13) cost recovery responsibility split of 86.7% and 13.3%, respectively, currently applied to the ETIP amounts authorized for recovery in Case 15-M-0252 (Matter of Utility Energy Efficiency Programs). These costs will be carefully allocated in accordance with the JP provisions, so that some customers will remain exempt from responsibility for these costs in the same way that they enjoyed exemption from costs under the Energy Efficiency Tracker (EE Tracker).

In addition, the JP proposes that the Company be allowed to defer any over- or underspending for the period July 1, 2018, through June 30, 2021. At December 31, 2021, any net cumulative under expenditures will be deferred by the Company for funding future energy efficiency programs, but any over-spending will be absorbed by the Company. During the

[113] Id., pp. 14-15.

period of the rate plan, the Company still will be required to file ETIPs, however, which eventually will become a more comprehensive System Energy Efficiency Plan.

Along with the increased budgets, the JP proposes a 40% increase of the Company's current ETIP targets for energy efficiency programs, with corresponding EAM incentives for achieving or exceeding those targets, all of which will result in significant electric and gas savings. As proposed in the JP, the Company must achieve electric energy efficiency net savings of 47,936 MWh per year in the calendar years 2018 through 2021, and gas energy efficiency savings of 52,214 Dth per year in the same period.[114] The Energy Efficiency EAM targets for electric and gas should be converted to gross MWh and gross MMBtu targets, respectively, for electric and gas to be consistent with the Order issued on March 15, 2018 in Case 15-M-0252.[115] Therefore, the minimum gross MWh target for electric energy efficiency savings is 53,262 MWh and the minimum gross MMBtu target for gas is 58,016 MMBtu. The revised 2018 through 2021 minimum, midpoint, and maximum energy efficiency EAM targets for both electric and gas are reflected in the Appendix W Revised Sheets 9 and 10 of 13 which are appended to this order as Attachment 3.

In addition, under the JP, Central Hudson will implement a moderate income electric efficiency offering in Rate Year 2. The JP requires the Company to collaborate with NYSERDA and convene a stakeholder meeting by December 31, 2018, to receive input on this program.

---

[114] Hearing Exhibit 22, Joint Proposal, Appendix W, Sheets 9 and 10 of 13.

[115] Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020 (issued March 15, 2018).

In support of the JP, Staff notes that the Company originally had been opposed to the change in its recovery of energy efficiency program costs through base rates, but that the Company ultimately agreed to Staff's proposal. According to Staff, this change in recovery method will not affect customers' overall energy bills because no matter how the costs are recovered, the Company is not authorized to exceed the energy efficiency portfolio budgets set by the Commission. Staff also highlights the provision of the JP that provides for a downward-only reconciliation of ETIP costs over the term of the rate plan.

CLP says the JP represents important progress toward strengthening Central Hudson's energy efficiency savings targets. CLP notes that the savings targets for 2018 initially proposed by the Company were nearly 25% lower than the value established in its ETIP, and only half of the level of reduction the Company achieved in 2016.[116] CLP opines that increasing energy efficiency is a cost-effective way to reduce carbon emissions and ultimately will result in savings for ratepayers.

For its part, Pace states that it supports the targets, because the targets initially proposed by Central Hudson were not sufficiently ambitious. According to Pace, because the targets in the JP are more aggressive than those initially proposed in the Company's ETIP, they do more to promote REV goals.[117] Pace also supports the moderate income energy efficiency offering, stating that such program will extend energy efficiency benefits to a broader range of

[116] CLP Statement, p. 5.

[117] Statement of Pace Energy and Climate Center in Support of JP (Pace Statement), pp. 11-13.

customers, and the stakeholder process will allow Pace and other parties to actively participate in developing the program.[118]

We agree that the JP recommends a reasonable program of energy efficiency budgets and targets. They greatly improve upon the targets initially contemplated by Central Hudson, thereby providing strong incentives to achieve more aggressive energy savings. In that respect alone, they comport with our stated policies specifically and the public interest generally. Importantly, the significant increases in the historic levels of the Company's electric and gas energy efficiency targets are coupled with only a modest increase in the budgets. These modest budget increases can be accommodated reasonably within an overall rate plan that balances the need for energy efficiency against affordability concerns.

While we find that the budgets and targets are reasonable based on current information and policies, we do note that this issue could be re-examined and reopened as it relates to the joint Department of Public Service-NYSERDA comprehensive energy efficiency White Paper, New Efficiency: New York, that was filed in April, 2018 in response to the Governor's State of the State Address.[119] The JP specifically contemplates the reopening of the rate plan we establish here to accommodate the outcome of generic proceedings such as that considering issues related to energy efficiency targets and policy.

Earnings Adjustment Mechanisms

As noted above, EAMs are proposed in the JP as a tool to incentivize actions by the Company and its customers to

---

118 Id., pp. 13-14.

119 On February 8, 2018, a new case (Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative) was started to consider the issues related to energy efficiency targets and policy.

improve the efficiency of the electric and gas systems and of customers' electric and gas usage, to promote development of the market for distributed energy resources, and to shift usage to cleaner technologies.[120] All these actions advance State policies to reduce emissions of greenhouse gases and other pollutants while improving the reliability and resiliency of our energy infrastructure.

Under the JP, the Company would adopt EAMs for its electric and gas businesses starting January 1, 2018, with the EAMs to be measured on a calendar year basis. The JP proposes five electric EAMs, comprised of a total of seven metrics, and one gas EAM, comprised of one metric. Each metric would contain targets set at minimum, midpoint, and maximum performance levels that generally would become more stringent each calendar year. The Company will earn a pre-tax earnings adjustment on a prorated basis for performance between the minimum and midpoint performance levels, and between the midpoint and maximum performance levels. Central Hudson has the potential to earn a maximum earnings adjustment of $2.0 million in 2018, $4.3 million in calendar year 2019, $4.7 million in calendar year 2020, and $4.9 million in calendar year 2021 for its electric business. For its gas business, Central Hudson has the potential to earn a maximum earnings adjustment of $0.18 million in 2018, $0.39 million in calendar year 2019, $0.44 million in calendar year 2020, and $0.47 million in calendar year 2021. All EAM targets and incentives are set forth in JP Appendix W.

The five proposed electric EAMs are System Efficiency, Electric Energy Efficiency, Customer Engagement, Environmentally

---

[120] EAMs were proposed as a ratemaking tool in Case 14-M-0101, Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (REV Track Two Order).

Beneficial Electrification, and Interconnection. The System Efficiency EAM is composed of two metrics – Peak Reduction and DER Utilization. The Peak Reduction metric would incentivize Central Hudson to reduce its New York State Independent System Operator (NYISO) Zone G-J Locality peak. The DER Utilization EAM metric incentivizes Central Hudson to work with third parties to expand the use of DER resources including large solar, combined heat and power, standalone or behind the meter electric energy storage resources, and fuel cells in Central Hudson's service territory.

The Energy Efficiency EAM is composed of three metrics: (1) Electric Energy Efficiency; (2) Residential Electric Energy Intensity; and (3) Commercial Electric Energy Intensity.[121] The Electric Energy Efficiency EAM incentivizes the Company to achieve energy efficiency savings in calendar years 2018 through 2021 that are significantly above its annual savings target of 34,240 MWh. It will be measured as the sum of MWh savings from all of Central Hudson's administered electric ETIP Energy Efficiency Programs, including behavioral programs, which may be utilized to achieve MWh targets. As a precondition to earning the incentive associated with this metric, the Estimated Useful Life (EUL) of the Company's ETIP portfolio must be at least 90% of the current weighted average EUL for New York State utilities, and earnings related to this metric will be prorated between this level and the Company's historic EUL. The Electric Energy Efficiency EAM is subject to change pursuant to

[121] An Outreach and Education budget for the Electric Energy Intensity Metric is included in rates as indicated in JP Appendix A.

a Commission determination in the Energy Efficiency Proceeding.[122]

The Residential Electric Energy Intensity EAM and the Commercial Electric Energy Intensity EAM will incentivize Central Hudson to reduce residential (SCs 1 and 6) and commercial (SC 2 non-demand) customers' total usage on a per customer basis. The Customer Engagement EAM incentivizes the Company to increase residential customer participation in Voluntary Time of Use (VTOU) rates.

The Environmentally Beneficial Electrification EAM incentivizes the Company to reduce carbon emissions by facilitating greater penetration of technologies that utilize electricity and reduce carbon emissions relative to traditional technologies that rely on more carbon intensive fuel sources. Examples of these technologies include geothermal heating and cooling, air source heat pumps for heating and cooling, and electric vehicles. It will be measured as the lifetime short tons of avoided carbon dioxide from environmentally beneficial electrification technologies as identified in the Company's Carbon Reduction Implementation Plan, which will be filed within 30 days of the issuance of this order.

Finally, the Company may petition the Commission for approval of metrics and targets consistent with a future Commission order regarding the Interconnection EAM Metric in Case 16-M-0429.[123] The Company will reserve 1 basis point minimum, 2.5 basis points midpoint, and 5 basis points at maximum for interconnection-related EAMs.

---

[122] Hearing Exhibit 22, Joint Proposal, p. 68; see also Appendix W, Sheets 3-4.

[123] Case 16-M-0429, In the Matter of Earnings Adjustment Mechanism and Scorecard Reforms Supporting the Commission's Reforming the Energy Vision.

The Gas Energy Efficiency EAM will incentivize the Company to achieve energy efficiency savings that are significantly above 37,296 dekatherms (Dth).[124] It will be measured as the sum of Dth savings from all Central Hudson's administered gas ETIP Energy Efficiency Programs. As a precondition to earning the incentive associated with this metric, the EUL of the Company's ETIP portfolio must be at least 90% of its historic EUL for Central Hudson's Gas ETIP portfolio, and earnings related to this metric will be prorated between this level and the Company's historic EUL. Like its electric counterpart, the Gas Energy Efficiency EAM is subject to change pursuant to a Commission determination in the Energy Efficiency Proceeding.

The JP provides that the incentives associated with Electric EAMs will be recovered through the Miscellaneous Charges EAM Factor, which will be a component of the Company's Energy Cost Adjustment Mechanism. Recovery will be over a 12-month period commencing with the first billing batch in July following the EAM measurement period. Recovery will be on a kWh basis for non-demand customers and on a kW basis for demand customers, with rates determined for each service classification or sub-classification based on the aggregate results of the following allocation methodologies: (1) Peak Reduction EAM, allocated using the transmission demand allocator; (2) Energy Efficiency, Energy Intensity and Environmentally Beneficial Electrification EAMs, allocated using the energy allocator; and (3) DER Utilization EAM, allocated using three allocators which will be equally weighted (coincident peak, non-coincident peak, and energy allocator). These rates will be applied to the energy (kWh) or demand (kW) deliveries, as applicable, on the

[124] 37,296 dekatherms (Dth) is the current net savings target for the gas ETIP.

bills of all customers served under SCs 1, 2, 3, 5, 6, 8, 9, 13, and 14. Customers taking service under SC 14 will be billed the rate applicable to their parent service classification, which is the service classification that the customer would otherwise qualify for based on the customer's usage characteristics.

Recoveries (11 months actual, one month forecasted) will be reconciled to allocable costs for each 12-month recovery period ending June 30, with any over or under recoveries included in the development of succeeding Miscellaneous Charges EAM Factors. Reconciliation amounts related to the one-month forecast will be included in the next subsequent rates determination.

For billing purposes, recovery for non-demand customers will be included in Miscellaneous Charges, with the combined amount shown as one line item on customer bills. Cost recovery for demand customers will be through Miscellaneous Charges II, a separate line item on customer bills.

Incentives associated with Gas EAM will be recovered through the new Gas Miscellaneous Charge mechanism. Recovery will be over a 12-month period commencing in July, and will be on a Ccf basis with a uniform factor developed, based on forecast Ccf over the respective recovery period, and applied to all deliveries on the bills of all customers served under SCs 1, 2, 6, 11, 12, 13, 15 and 16. Recoveries (11 months actual, one month forecast) will be reconciled to allocable costs for each 12-month recovery period ending June 30, with any over or under recoveries included in the development of succeeding Miscellaneous Charges EAM Factors. Reconciliation amounts related to the forecast versus actuals for the final month of the rate plan will be included in the next rate determination.[125]

[125] Hearing Exhibit 22, Joint Proposal Appendix W, Sheets 12 and 13.

MI notes that Central Hudson will have an opportunity to earn EAMs, funded by customer surcharges, that could cost electric and gas customers almost $17.4 million over the three-and-one-half year period they are proposed to be in effect, if Central Hudson achieves the prescribed maximum performance levels. While MI states its disagreement with the concept of positive-only EAMs for utility shareholders and expresses skepticism that their implementation will provide customers with net benefits that could not have been achieved at a substantially lower potential cost or no cost, it states that, given the Commission’s current policies requiring the funding of EAMs, the specific EAMs set forth in the JP are acceptable to it.[126]

Pace submits that the JP’s proposed EAMs adequately reflect REV principles and other State policies aimed at reducing energy usage and integrating DERs into the grid and are highly beneficial to customers and the environment.[127] Pace states that the EAM targets for electric and gas energy efficiency energy are greater than historical levels and may be increased when the Commission acts on Staff’s Earth Day Energy Efficiency Proposal.

Noting its opposition to funding the expansion of the natural gas system, Pace contends that the JP proposal concerning the Environmentally Beneficial Electrification EAM is superior to the Company’s original proposal because it no longer includes gas conversions as a metric.[128] Pace supports the System Efficiency EAM targets, stating that reducing system peaks is very important because peak demand drives many capital

---

[126] MI Statement, pp. 21-22.

[127] Pace Statement, pp. 11-16.

[128] CLP also supports the elimination of gas expansion proposals. CLP Statement, p. 4.

improvements, transmission and distribution investments, and system costs, and that generation used only during peak periods is associated with higher rates of marginal pollutant emissions. Finally, Pace notes that the DER utilization metric provides incentives for increased DER penetration, which will be highly beneficial to customers and the environment.

Among other things, NY-GEO and Bob Wyman express support for the reduction of gas expansion that is reflected in the JP and for the funding that is being made available for both electrical energy efficiency and beneficial electrification.[129]

The Company states that the agreed-to EAMs reasonably balance the competing interests of shareholders and customers, as well as environmental concerns, to establish new incentives that will increase the Company's existing efforts to promote energy efficiency and the integration of new clean energy technologies. It notes that System Efficiency EAM reflects various compromise positions between the Company, Staff, and the parties, while the Customer Engagement EAM reflects compromises between the litigating positions of it and Staff. It contends that the EAMs should be adopted without modification.[130]

Staff asserts that the JP’s EAM provisions balance shareholder, customer, environmental, and public interests to establish new incentive mechanisms that will align the Company’s business activities with New York State energy and climate policy goals. Staff adds that the EAMs will support energy efficiency programs that will integrate new clean energy technologies from emerging markets. Staff also adds that the proposed EAMs are within the range of outcomes advocated in the parties’ initial and rebuttal testimony. Staff concludes that

---

129 NY-GEO (letter of) support for the Joint Proposal; Statement in Support of Joint Settlement Proposal, pp. 4-5.

130 Company Statement, pp. 46-52.

the EAM proposals are reasonable, in the public interest, and should be adopted.[131]

We find that the proposed incentives are appropriately set at amounts that will encourage the Company to satisfy EAM target levels. We acknowledge the important balance struck by the JP signatories between the objective to incentivize Company behavior using ratepayer funds and the need to minimize increases in rates, and we recognize that this is the first time that Central Hudson will be operating under EAMs. Based on the experience gained during this rate plan, the Commission can review the appropriateness of the incentive amounts in the Company's next rate case. However, for now, we agree with the JP signatories that the EAM targets and mechanisms established in these proceedings will advance important State policy objectives and goals and are in the public interest, and therefore should be adopted as proposed in the JP.

Natural Gas Safety and Reliability

The JP advances natural gas safety and reliability and reduces its environmental impact in several important ways. First, it continues the replacement of leak prone infrastructure and accelerates the repair of non-hazardous leaks. One way this is accomplished is through a new positive revenue adjustment related to leak repair. When added to the program focused on increased adoption by residential customers of methane detection technology, natural gas leaks and the resulting greenhouse gas emissions will be significantly reduced.

The Company is being encouraged through this JP to pursue non-pipes alternatives to meet demand for heating fuels. One way is through the incentives focused on geothermal heating and cooling, mentioned above, but the Company has also committed

[131] Staff Statement, pp. 84-91.

to pursue additional natural gas efficiency, demand response programs, and will issue an RFP focused on non-pipes alternatives that can displace traditional infrastructure projects. When combined with the reductions in methane leakage, the programs that seek to replace natural gas usage with other means of providing space heating or reducing fuel consumption will help ensure the transition to lower carbon energy markets in New York State.

Customer and Minimum Charges

In its litigated case, the Company recommended increasing the electric customer charge and the gas minimum charge so they would be closer to the embedded costs of service.[132] Staff acknowledged that the Company's proposed changes to the residential electric customer charges were cost-based. Staff recommended keeping the electric customer charges and gas residential minimum charge at current levels, pending a determination in the VDER proceeding as to how they should be changed to better achieve New York's energy policy goals.[133] UIU, PULP, CLP, Bard College, and Pace recommended reducing such charges.[134] Pace also recommended that the Company be directed

---

[132] Hearing Exhibit 1, Pre-filed direct testimony of the Central Hudson's Forecasting and Rates Panel, pp. 54, 58. See also Company Statement, pp. 25-27.

[133] Hearing Exhibit 16, Pre-filed direct testimony of Staff Electric Rates Panel, p. 23, and Pre-filed direct testimony of the Staff Gas Rates Panel, pp. 44-45.

[134] Hearing Exhibit 14, Pre-filed direct testimony of UIU Rate Panel, pp. 20-21; Hearing Exhibit 10, Pre-filed direct testimony of PULP Witness Yates, p. 8; Hearing Exhibit 18, Pre-filed direct testimony of CLP Witness Metzger, p. 21; and Hearing Exhibit 21, Pre-filed direct testimony of Bard College Reliability, Affordability and Sustainability Panel, p. 21.

to prepare a new model for classifying customer costs and calculating customer and minimum charges.[135]

The proposed residential customer and minimum charge amounts, which are a reduction from the current amounts, are the product of compromise between the litigation positions of the Company, Staff, Pace, Acadia Center,[136] UIU, PULP, and CLP. They are recommended as a means of garnering support from some Signatory Parties and some non-signatory parties. We approve them but note that such proposals will not take precedence over any subsequent Commission order that is applicable to Central Hudson and to the design of its rates.[137]

Management and Operations Audit Compliance

Upon the application of a gas or electric corporation for a major change in rates, Public Service Law (PSL) §66(19)(c) requires that the Commission review the corporation's compliance with the directions and recommendations made previously by the Commission as a result of the most recently completed management and operations audit. Staff addressed the

---

135 Hearing Exhibit 7, Pre-filed direct testimony of Pace Witness Rábago, pp. 10-11. See also Pace Statement, pp. 3-5.

136 Acadia Center supports the JP because it reduces the residential electric customer charges. Statement in Support of Joint Proposal by Acadia Center, pp. 3-8.

137 The JP expressly notes that these reductions are not intended to set statewide policy or take precedence over any subsequent Commission order applicable to Central Hudson regarding rate design. See Hearing Exhibit 22, Joint Proposal, p. 37.

most recently completed management and operations audits of Central Hudson in its testimony in this case.[138]

In 2009, the Commission instituted a comprehensive management and operations review of Central Hudson's gas and electric businesses, with a specific focus on the Company's construction program planning processes and operational efficiency.[139] On February 11, 2010, the Commission approved the selection of NorthStar Consulting Group (NorthStar) to perform the audit. On May 20, 2011, the Commission issued its "Order Directing the Submission of an Audit Implementation Plan" to address the recommendations for improvement that were provided in NorthStar's final audit report, publicly published the same day. The Company filed its audit implementation plan on July 1, 2011. In an audit closeout letter, dated February 24, 2016, Staff stated that all the recommendations from the audit had been satisfactorily implemented.

Because audits must be performed every five years, in 2016, the Commission instituted a comprehensive management and operations review of Central Hudson's gas and electric businesses that, like the 2009 audit, also focused on the

---

[138] See Hearing Exhibit 23, Lavery Affidavit and Pre-filed direct testimony of Staff Witness Lavery. Witness Lavery also provided testimony concerning the status of the audits in Case 13-M-0314, Review of Reliability and Customer Service Systems of NYS Gas and Electric Utilities (instituted July 16, 2013) (Data Audit) and Case 13-M-0449, Operations Audit of Major Utility Internal Staffing Levels and Use of Contractors for Selected Core Functions (Staffing Audit). We approved the implementation plans for the Data Audit on March 10, 2017, and the Staffing Audit on December 15, 2017. The Company currently is in the implementation stage with respect to the recommendations from those audits.

[139] Case 09-M-0764, Comprehensive Management and Operations Audit of Central Hudson Gas and Electric Corporation's Electric and Gas Businesses, Letter to Carl Meyer (dated November 12, 2009).

Company's construction program planning processes and operational efficiency.[140] On July 14, 2016, the Commission approved the selection of Overland Consulting Inc. (Overland) to perform the audit. Overland's final audit report was issued by the Commission on October 24, 2017. Initial and updated implementation plans were filed by the Company on November 17 and December 14, 2017. We note that the Company has begun implementing some of the Overland audit recommendations.

Pursuant to PSL § 66(19), we find that Central Hudson is currently in compliance with the directions and recommendations made in the most recently completed management and operations audits.

Other Miscellaneous Provisions

There are several other areas agreed to by the Signatory Parties, including, but not limited to, the continuation of existing electric and gas economic development fund programs; elimination of per-transaction fees associated with payment centers and payment of utility bills by credit/debit card; training for Company customer service representatives; and the implementation of electronic deferred payment agreements. These provisions demonstrate the comprehensive nature of the JP as the parties have resolved numerous complex rate and policy issues, while providing the Company's customers with some measure of rate predictability for at least three years.

Section XXV, subsections B, C, D, E, H, I, and J, of the JP do not require our adoption. There are no disputes about any of these terms but this rate plan need not and should not

---

[140] Case 16-M-0001, In the Matter of a Comprehensive Management and Operations Audit of Central Hudson Gas & Electric Corporation, Letter to James P. Laurito (dated March 17, 2016).

include terms that govern the relationship among the parties. Our decision not to adopt such provisions does not indicate or imply that such terms are not important, it merely reflects that they are unnecessary for this rate plan.

Future REV-Based Initiatives

The Commission notes that the JP was filed while several REV-related proceedings continue to make progress. The Company may and is encouraged to petition the Commission for approval of REV-based initiatives that advance goals established in this rate case at improved economics, and especially so if the Company has identified opportunities for shared savings. Under REV, New York seeks to lower the costs and speed of the achievement of the State's policy goals through accelerating the deployment at scale of solutions that create the most economic value for both consumers and the State's energy system, drawing on innovation and investment from all sectors.

The Company has untapped potential to work with innovative third parties to develop alternative solutions to achieve the results committed to by the Company in this proceeding at lower ratepayer expense, at a faster rate, or both. These solutions can take the form of technology or deployment alternatives that are more optimal for specific locations or other utility needs, or business model alternatives that yield additional savings or produce additional revenues, in both cases yielding economics which can be shared among customers, the innovative provider, and the Company.

Mechanisms for such shared savings/benefits can take the form of the EAMs identified in this JP for specified outcomes, a non-wires alternative sharing mechanism, sharing of platform service revenues, or future shared savings/benefits constructs designed for specific opportunities and approved by the Commission. The Commission requires the Company to actively continue and expand its work with third parties to identify opportunities for such solutions, to develop them as warranted, and to bring them forward to the Department and/or the Commission as needed. Such third parties are likely to be customers, providing payment to the Company for valuable services rendered by the Company, as well as providers who receive payment from the Company for valuable services rendered to the Company. The Commission recognizes that achieving such benefits from third parties may require the Company to enter into long-term contracts. As these contracts would represent long-term financial liabilities, the Commission will require the Company to demonstrate long-term net savings or benefit structures that would support entering into the contract. The Commission specifically encourages the Company to bring forward shared savings/benefits approaches to compensation as an alternative or complement to traditional cost recovery or rate-based approaches.

Given the State's policy objectives, especially promising opportunities for such solutions include (but are not limited to):

- AMI, which offers the potential for alternative business models that can generate revenues to the Company;
- Data provision, including system and usage data (subject to necessary protections), to enable third parties to develop novel and economic solutions to Company needs;
- Energy efficiency, which offers the potential for market-based solutions to reduce the cost of achieving energy savings or to offset those costs by revenues or savings elsewhere in the energy system;
- Low and moderate income focused initiatives, which can provide benefits to the energy system through strategic

deployment of distributed resources or energy efficiency in locations or against time-windows where the energy system faces constraints;

- Non-wire alternatives and non-pipe alternatives, explored as a universal practice as an alternative to traditional investments that meet the Company's predefined NWA suitability criteria;
- Grid modernization, including the use of technology to deliver reliability and system functionality at the best economics for ratepayers;
- Supply cost reduction, where novel approaches deliver savings in commodity and capacity payments; and
- Operating cost reduction, where novel approaches deliver savings in asset utilization, in operations expenditures, or in administrative/central expenditures.

Across all of these opportunities, the Company is encouraged to develop processes that invite and consider proposals that address proposer-identified opportunities (consistent with stated system needs) and whose solution would provide economic value as described above.

CONCLUSION

We conclude from our review of the record that the JP terms that we are adopting appropriately and reasonably balance the interests of ratepayers and the Company. The JP provides sufficient funding, via modest rate increases, that will allow Central Hudson to maintain safe and reliable service and attract the capital needed to ensure the Company's long-term viability, while mitigating the ratepayer impact by using credits and by taking other steps that moderate bill impacts. The execution of the JP by several parties with diverse and often adverse interests demonstrates the parties' diligent efforts to address and resolve the outstanding issues in a comprehensive and practical fashion. Finally, the terms of the JP evidence its consistency with our environmental, social and economic policies and those of the State. In consideration of the foregoing, we find that the terms of the JP are in the public interest, and we adopt the majority of them as a rate plan for Central Hudson.

The Commission orders:

1. The rates, terms, conditions, and provisions of the Joint Proposal dated and filed April 18, 2018, in these proceedings and attached hereto as Attachment 1, except for Section IV, subsection F; and Section XXV, subsections B, C, D, E, H, I, and J; are adopted and incorporated herein.

2. Central Hudson Gas & Electric Corporation is directed to file cancellation supplements, effective on not less than one day's notice, on or before June 21, 2018, cancelling the tariff amendments and supplements listed in Attachment 2.

3. Central Hudson Gas & Electric Corporation is authorized to file, on not less than one day's notice, to take effect on July 1, 2018, on a temporary basis, such tariff changes as are necessary to effectuate the terms of this Order for the rates in the rate year beginning July 1, 2018, including tariff changes necessary to effectuate removal of the EE Tracker surcharge component of the System Benefit Charge, and to incorporate any tariff amendments that were previously approved by the Commission since the tariff amendments listed on Attachment 2 were filed.

4. Central Hudson Gas & Electric Corporation shall serve copies of its filings on all active parties to these proceedings. Any party wishing to comment on the tariff amendments may do so by filing its comments with the Secretary

to the Commission and serving its comments upon all active parties within ten days of service of the tariff amendments. The amendments specified in the compliance filings shall not become effective on a permanent basis until approved by the Commission and will be subject to refund if any showing is made that the revisions are not in compliance with this Order.

5. On December 21, 2017, Central Hudson Gas & Electric Corporation consented to extend the suspension period through and including July 24, 2018. On January 24, 2018, Central Hudson Gas & Electric Corporation consented to an extension of the suspension period through and including August 23, 2018. On February 20, 2018, and March 23, 2018, Central Hudson Gas & Electric Corporation consented to an extension of the suspension period through and including September 22, 2018 and October 22, 2018, respectively. Because this order is made within the suspension period to and including June 24, 2018, the request for a make-whole (set forth in JP Section IV, subsection F) is dismissed as moot.

6. Central Hudson Gas & Electric Corporation is directed to file tariff changes in 2019 and 2020 to effectuate the rates for Rate Year 2 and for Rate Year 3. The Rate Year 2 changes shall be filed on not less than 30 days' notice to be effective on a temporary basis on July 1, 2019. The Rate Year 3 changes shall be filed on not less than 30 days' notice to be effective on a temporary basis on July 1, 2020.

7. The requirement of the Public Service Law §66(12)(b) and 16 NYCRR 720-8.1 that newspaper publication be completed prior to the effective date of the amendments for Rate Year 1 are waived and Central Hudson Gas & Electric Corporation is directed to file with the Secretary to the Commission, no later than six weeks following the effective date of the amendments, proof that a notice to the public of the changes set

forth in the amendments and their effective date had been published once a week for four consecutive weeks in one or more newspapers having general circulation in the service territory. The requirements of Public Service Law §66(12)(b) and 16 NYCRR 720-8.1 are not waived with respect to Rate Year 2 and Rate Year 3.

8. In the Secretary's sole discretion, the deadlines set forth in this order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least one day prior to the affected deadline.

9. The proceedings in Cases 17-E-0459 and 17-G-0460 are continued.

By the Commission,

(SIGNED) KATHLEEN H. BURGESS
Secretary

Exhibit EDH-6
Central Hudson Gas & Electric Corporation’s Non-Pipeline Alternatives Annual Report (filed pursuant to New York Public Service Commission Case 17-G-0460.)

Paul A. Colbert
Associate General Counsel
Regulatory Affairs

December 2, 2019

Hon. Michelle L. Phillips
Acting Secretary
New York State Public Service Commission
Agency Building 3
Albany, NY 12223-1350

Re: Case 17-G-0460 - *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service*; Non-Pipeline Alternatives Compliance Filing

Dear Secretary Phillips:

In compliance with the Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan issued on June 14, 2018 in the above-referenced case, Central Hudson Gas & Electric Corporation hereby submits its Non-Pipeline Alternatives Annual Report.

Questions regarding this filing may be directed to Mark Sclafani at (845)486-5979 or msclafani@cenhud.com.

Respectfully submitted,

/s/*Paul A. Colbert*

Paul A. Colbert
Associate General Counsel
Regulatory Affairs

284 South Avenue
Poughkeepsie, NY 12601

(845) 452-2000
Phone: (845) 486-5831 Cell: (614) 296-4779
Email: pcolbert@cenhud.com
www.CentralHudson.com

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	**Case 17-G-0460**

Central Hudson Gas & Electric Corporation's Non-Pipeline Alternatives Annual Report

December 2, 2019

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
284 South Avenue
Poughkeepsie, N.Y. 12601

People. Power. Possibilities.
Central Hudson
A FORTIS COMPANY

Central Hudson Gas & Electric Corporation
Case 17-G-0460
Non-Pipeline Alternatives – Annual Report

Table of Contents

Background

Non-Pipeline Alternatives ("NPAs") are projects designed to displace the need for traditional gas infrastructure investment. Central Hudson Gas & Electric Corporation ("Central Hudson" or "the Company") proposed to incorporate NPA projects into its system planning process within its 2017 Rate Case. [1] On June 14th, 2018 the Commission issued an Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan ("Order"). The order adopted proposed NPA strategies and required the Company to submit an implementation plan and subsequent annual report for each identified NPA project.

Central Hudson provides the following annual report on the progress of each of our NPA projects.

Non-Pipeline Alternative Projects

The Company is pursuing two categories of NPA projects, both of which employ non-traditional solutions to avoid traditional infrastructure construction. The two categories are as follows:

1) *Load Growth-Based Projects*

These types of projects would be designed to manage locational constraints that are associated with peak demand.

2) *Transportation Mode Alternatives*

Central Hudson's transportation mode alternatives projects are designed for strategic abandonment of leak prone pipe through electrification where it is more cost effective than replacement and system reliability is not negatively impacted.

Load Growth-Based Projects

Overview

In an effort to understand location-specific gas distribution costs, Central Hudson employed a consultant, Demand Side Analytics, to perform a system-wide gas distribution avoided costs study. The

[1] Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.*

study includes the analysis of approximately 40 localized gas systems throughout Central Hudson's gas service territory. Probabilistic forecasting methods, including simulations of nonlinear growth trajectories, have been used to identify areas of demand growth. This study follows a similar strategy employed for the electric system ("Location Specific T&D Avoided Cost Study Report"[2]), the results of which were included within the Company's DSIP[3]. These results have been combined with an analysis of distribution capacity to identify predicted constraints. Once the study results are finalized, any constrained areas will be evaluated as potential candidates for a load growth-based NPA solution or incorporated into the development of a system-wide value.

Current Status

Central Hudson is currently finalizing the results of the system-wide gas distribution avoided costs study and expects to confirm suitable areas for NPA solutions. Once identified, a technology agnostic market solicitation will occur, following the procedure put in place for Non-Wires Alternatives. Following the solicitation, the Company will file an Implementation Plan in accordance with the Order.

Transportation Mode Alternatives

Overview

Central Hudson's current Transportation Mode Alternatives ("TMA") are designed to facilitate strategic abandonment of leak-prone pipe ("LPP"). LPP is considered to be any natural gas distribution piping that is not made of either plastic or "protected"[4] steel pipe. Common leak-prone materials are wrought iron, cast iron, and unprotected steel. In order to improve safety and reduce ongoing maintenance costs, LPP that cannot be protected or abandoned must be replaced with new plastic pipe. LPP replacement is costly; the Company estimates that it will cost approximately $1.9 million per mile on average in 2019.[5] For a TMA initiative to be successful, each customer's natural gas service would need to be retired.

[2] *Case 15-E-0751 – in the Matter of the Value of Distributed Energy Resources, Central Hudson Gas & Electric Corporation's Avoided T&D Cost Study. July 31, 2018*
[3] *Central Hudson Distribution System Implementation Plan. Revised July 31, 2018*
[4] Pipelines are protected either physically with coatings or with cathodes and sacrificial anodes to prevent corrosion.
[5] Joint Proposal "Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service." Section XVII.E*

Approach

To date, the Company has identified three separate project locations throughout the service territory where it is likely feasible and cost-effective to permanently retire sections of LPP. These three areas, referred to as "cases", were identified in the Company's Implementation Plan & Compliance Filing for Non-Pipe Alternatives ("Implementation Plan").[6] The three locations in Newburgh and Saugerties contain approximately 20 residential customers in total.

The Company is utilizing ICF along with its existing HVAC Trade Ally network to deliver these NPA project solutions. Due to the small number of customers and the need for 100% participation within each area, the Company is utilizing a direct-install approach. Central Hudson is utilizing high efficiency cold climate air-source heat pumps and electric heat pump water heaters to replace the primary natural gas end uses.[7] Other natural gas appliances such as cooking ranges and clothes dryers will be replaced with electric units where applicable. The standard conversion package will be offered at no cost to the customer.[8]

Current Status

The Company initiated its first TMA shortly after filing its Implementation Plan. The case is meeting the expectations of the Company's initial timeline milestones. The initiative utilized a highly targeted marketing approach, followed by customer education and enrollment. The Company has completed its first customer conversion which included converting use of natural gas equipment to efficient electric heating and hot water end uses. Recruitment for the remaining two cases will begin early next year, targeting case completions by the end of 2020.

Benefit Cost Analysis

Central Hudson primarily evaluated the economics of its three ongoing TMA cases based on the Societal Cost Test prescribed within the Company's BCA Handbook.[9] Where applicable, the valuation methodologies from the BCA Handbook, which is primarily intended for electric projects, have been

---

[6] Case 17-G-0460 - Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Three Transportation Mode Alternatives, Filed June 21st 2019

[7] Customers will be educated and have the option to install a geothermal system by covering the incremental cost above the incentive provided for air-source heat pumps

[8] There may be cases where customers desire an "upgraded" appliance, the incremental cost of which would be borne by the customer.

[9] Central Hudson Gas & Electric Benefit-Cost Analysis (BCA) Handbook, Version 2.0, Revised July 31st, 2018.

used. Some natural gas specific benefits and costs have been included in a way that is similar to those within the BCA Handbook. Relevant benefits and costs have been included in a detailed BCA analysis, developed with support of third party consultants.

The Company estimates these NPA cases to have a Benefit Cost Ratios (BCR)[10] greater than 1.0 based on the three tests included in the BCA Handbook, as reported in more detail within the Implementation Plan. The BCA results within the table below have been revised based on the most current assumptions. Although most BCA results have changed only slightly, the UCT result for Case 3 has changed moderately due to a correction that does not fundamentally affect the viability of the project.

Transportation Mode Alternative – Benefit Cost Ratio by Location			
Case	SCT	UCT	RIM
1	1.41	1.07	2.74
2	6.99	2.14	2.53
3	3.18	1.60	2.28
Weighted Average	3.34	1.64	2.21

[10] Benefit cost ratio, primarily determined by the societal cost test.

Exhibit EDH-7
Selected responses from PGW to Clean Air Council data requests.

Philadelphia Gas Works
Case Name: R-2020 BRC Rate Case TBA
Docket No(s): BRC 2020 Rate Case

Response to Discovery Request: CAC-01-CAC-01-5
Date of Response: 6/10/2020
Response Provided By: Denise Adamucci and Gregory Stunder

Question:

Please provide all analyses, reports, or cost-benefit studies produced by or for PGW concerning the impact that changing the balance of fixed and variable charges on customer bills would have on PGW's EnergySense or any other PGW energy efficiency programs. Please provide all analyses in their native electronic format with formulas intact.

Attachments: 0

Response:

PGW has not conducted such a study. Such a study would likely not provide useful results or be cost-effective due to the large number of variables involved.

Philadelphia Gas Works
Case Name: R-2020 BRC Rate Case TBA
Docket No(s): BRC 2020 Rate Case

Response to Discovery Request: CAC-01-CAC-01-6
Date of Response: 6/10/2020
Response Provided By: Denise Adamucci

Question:

Please provide all analyses, reports, or cost-benefit studies produced by or for PGW concerning the impact that changing the balance of fixed and variable charges on customer bills would have on low-income PGW ratepayers. Please provide all analyses in their native electronic format with formulas intact.

Attachments: 0

Response:

PGW has not conducted such a study. Such a study would likely not provide useful results, as many low income customers participate in PGW's Customer Responsibility Program PIPP and are billed based on a percentage of their income.

Exhibit EDH-8
Excerpted pages 158 through 176 of Illinois Commerce Commission, Case No. 14-0224, Order dated January 21, 2015.

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
	:	
Proposed general increase in gas rates.	:	**14-0224**
(tariffs filed February 26, 2014)	:	
	:	
The Peoples Gas Light and Coke Company	:	
	:	
Proposed general increase in gas rates.	:	**14-0225**
(Tariffs filed February 26, 2014)	:	**(Consol.)**

<u>ORDER</u>

January 21, 2015

Contents

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
	:	
Proposed general increase in gas rates.	:	**14-0224**
(tariffs filed February 26, 2014)	:	
	:	
The Peoples Gas Light and Coke Company	:	
	:	
Proposed general increase in gas rates.	:	**14-0225**
(Tariffs filed February 26, 2014)	:	**(Consol.)**

ORDER

I. INTRODUCTION/ PROCEDURAL HISTORY

On February 26, 2014, 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" or "PUA") (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. 6-10, 18, 27, 42, 58, 66, 77, 89, 114, 124, 135.1. This tariff filing embodied a proposed general increase in gas service rates, revisions to the service classifications, riders and 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. Adm. Code Parts 285 and 286.

On February 26, 2014, The Peoples Gas Light and Coke Company ("Peoples Gas", "Peoples" 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. 5-9, 16, 19, 28, 42, 59, 68, 78, 95, 120, 140, 151.1. 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. Adm. Code Part 255.

The Commission issued a Suspension Order for North Shore's tariff filing on March 19, 2014, which suspended the tariffs to and including July 25, 2014, and further initiated Docket 14-0224. On July 9, 2014, the Commission issued a Resuspension Order that suspended these tariffs to, and including, January 25, 2015. However the deadline for Commission action is January 20, 2015.

The Commission issued a Suspension Order for Peoples Gas' tariff filing on March 19, 2014, which suspended the tariffs to and including July 25, 2014, and initiated Docket 14-0225. On July 9, 2014, the Commission issued a Resuspension Order that suspended these tariffs to, and including, January 25, 2015.

On April 1, 2014, North Shore and Peoples Gas each filed motions for protective orders in their respective Dockets, pursuant to Section 4-404 of the Act and 83 Ill. Adm. Code §§200.190 and 200.430. On April 14, 2014, the Administrative Law Judges ("ALJs") held an initial status hearing and, received the oral motion of Commission Staff ("Staff") to consolidate these cases and also orally approved a case schedule and data request response time schedule. On April 15, 2014, the Attorney General of the State of Illinois (the "Attorney General" or "AG") filed a response to North Shore's and Peoples' motions for a protective order. On May 7, 2014, the Utilities each filed a motion for entry of case management plan and schedule, pursuant to Section 10 101.1 of the Act and 83 Ill. Adm. Code §§ 200.190, 200.370, and 200.500. On August 8, 2014, Staff filed a motion to strike portions of the rebuttal testimony of the Utilities' witness Ms. Christine M. Hans and NS-PGL Ex. 26.3 in its entirety. On August 20, 2014, the Utilities filed a response to Staff's motion to strike portions of the rebuttal testimony of Ms. Christine M. Hans and NS-PGL Ex. 26.3. On August 27, 2014, Staff filed a reply in support of its motion to strike portions of the rebuttal testimony of Ms. Christine M. Hans and NS-PGL Ex. 26.3. On September 2, 2014, the ALJs denied Staff's motion to strike portions of the rebuttal testimony of Ms. Christine M. Hans and NS-PGL Ex. 26.3.

On September 4, 2014, Staff filed a motion for leave to file instanter the rebuttal testimony of Daniel G. Kahle, Dianna Hathhorn, and Janis Freetly. On September 10, 2014, the ALJs granted Staff's motion for leave to file instanter. On September 15, 2014, the Attorney General filed a motion to strike certain testimony of Utilities' witness Ms. Debra Egelhoff. On September 17, 2014, the Utilities filed a response to the Attorney General's motion to strike certain testimony of Utilities' witness Ms. Debra Egelhoff. On September 19, 2014, the Administrative Law Judges granted in part and denied in part the Attorney General's motion to strike certain testimony of Utilities' witness Ms. Debra Egelhoff. On October 17, 2014, Staff filed a motion for administrative notice of Peoples Gas' Qualifying Infrastructure Plant Surcharge Rider ("Rider QIP") information Sheet No. 9 and its supporting schedules and future Rider QIP informational Sheet Filing Nos. 10, 11, and 12 and their supporting schedules. On October 27, 2014, the Utilities filed a motion to correct the transcript of September 22-23, 2014 hearings. On October 29, 2014, the Utilities filed a response to Staff's motion for administrative notice relating to Rider QIP information sheets and supporting schedules. On October 29, 2014, the AG filed a motion to correct the transcript of September 22-23, 2014 hearings. On October 29, 2014, the AG filed a Motion to re-open the record of the People of the State of Illinois and admit into evidence a data request response from Docket No. 14-0496. *Wisconsin Energy Corporation, Integrys Energy Group, Inc., Peoples Energy, LLC, The Peoples Gas Light and Coke Company, North Shore Gas Company, ATC Management Inc., and American Transmission Company LLC*, Docket No. 14-0496. On October 30, 2014, the AG filed a revised version of that motion. On October 31, 2014, the Utilities filed a response to the AG's October 30th motion. On November 3, 2014, Staff filed a reply in support of its motion for administrative notice. On November 3, 2014, the AG filed a reply in support of its October 30th motion.

On November 5, 2014, the Administrative Law Judges granted Staff's motion for administrative notice with certain additional rulings. On November 5, 2014, the Administrative Law Judges granted the AG's October 30th motion. On November 10, 2014, the Administrative Law Judges granted motions to correct the transcript filed by the AG and the Utilities.

Petitions to Intervene

Petitions to Intervene were filed or appearances were entered on behalf of the AG; the Citizens Utility Board ("CUB"); the Retail Energy Supply Association ("RESA"); Merchandise Mart, the University of Illinois, Abbot Laboratories, Inc., AbbVie, Inc., and Ford Motor Company (collectively the "IIEC"); the Environmental Law and Policy Center ("ELPC"), (collectively, the AG and ELPC are "AG-ELPC") and the City of Chicago (the "City"), (collectively, the City, CUB and IIEC are "City-CUB-IIEC" or "CCI").

The Evidentiary Hearing

The evidentiary hearing was held September 22, 2014 and September 23, 2014, at the offices of the Commission in Chicago, Illinois. At the evidentiary hearings, the Utilities, Staff, and certain Intervenors entered appearances and presented testimony. The following witnesses testified on behalf of the Utilities: Dennis M. Derricks, Assistant Vice President, Regulatory Affairs, Integrys Business Support, LLC, North Shore and Peoples Gas (NS Exhibit ("Ex.") 1.0, PGL Ex. 1.0, NS-PGL 17.0, NS PGL Ex. 33.0); 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. 34.0); Paul R. Moul, Managing Consultant, P. Moul & Associates (NS Ex. 3.0, PGL Ex. 3.0, NS-PGL Ex. 19.0, NS-PGL Ex. 35.0); Kevin R. Kuse, Senior Load Forecaster, Integrys Business Support, LLC (NS Ex. 4.0, PGL Ex. 4.0); Christine M. Gregor, Director, Operations Accounting, North Shore and Peoples Gas, Integrys Business Support, LLC (NS Ex. 5.0, PGL Ex. 5.0 REV, NS-PGL Ex. 20.0); Sharon Moy, Rate Case Consultant, Regulatory Affairs, Integrys Business Support, LLC (NS Ex. 6.0, PGL Ex. 6.0, NS-PGL Ex. 21.0, NS-PGL Ex. 36.0); John Hengtgen, Consultant, Hengtgen Consulting, LLC (NS Ex. 7.0, PGL Ex. 7.0, NS-PGL Ex. 22.0 REV, NS-PGL Ex. 37.0); Mark Kinzle, General Manager, District Field Operations, North Shore Gas Company (NS Ex. 8.0, NS-PGL Ex. 31.0, NS-PGL Ex. 45.0); David Lazzaro, General Manager, District Field Operations, The Peoples Gas Light and Coke Company (PGL Ex. 8.0 2nd REV, NS-PGL Ex. 23.0 2nd REV, NS-PGL Ex. 38.0); John J. Spanos, Senior Vice President, Valuation and Rate Division, Gannett Fleming, Inc. (NS Ex. 9.0, PGL Ex. 9.0); Noreen E. Cleary, Assistant Vice President, Total Compensation, Integrys Energy Group, Inc. (NS Ex. 10.0, PGL Ex. 10.0, NS PGL Ex. 24.0); John P. Stabile, Tax Director, Integrys Business Support, LLC (NS Ex. 11.0, PGL Ex. 11.0, NS-PGL Ex. 25.0 REV, NS-PGL Ex. 39.0); Christine M. Hans, Manager, Benefits Accounting, Integrys Business Support, LLC (NS Ex. 12.0, PGL Ex. 12.0, NS-PGL Ex. 26.0, NS-PGL Ex. 40.0); Tracy L. Kupsh, Director, Operations Accounting IBS, Integrys Business Support, LLC (NS Ex. 13.0, PGL Ex. 13.0, NS-PGL Ex. 27.0, NS-PGL Ex. 41.0); Joylyn C. Hoffman Malueg, Rate Case Consultant – Regulatory Affairs, Integrys Business Support, LLC (NS Ex. 14.0, PGL Ex. 14.0, NS-PGL Ex. 28.0, NS-PGL Ex. 42.0); Debra

E. Egelhoff, Manager, Gas Regulatory Policy, Integrys Business Support, LLC (NS Ex. 15.0, PGL Ex. 15.0 REV, NS-PGL Ex. 29.0 REV, NS-PGL Ex. 43.0 REV); Thomas L. Puracchio, Manager, Gas Storage, Integrys Business Support, LLC (NS Ex. 16.0, PGL Ex. 16.0, NS-PGL Ex. 30.0, NS-PGL Ex. 44.0); James G. Robinson, General Manager – Customer Relations, Integrys Business Support, LLC (NS-PGL Ex. 32.0, NS-PGL Ex. 46.0).

The following witnesses testified on behalf of Staff: Dianna Hathhorn, Accountant, Accounting Department, Financial Analysis Division, Illinois Commerce Commission (Staff Ex. 1.0, Staff Ex. 6.0), Daniel Kahle, Accountant, Accounting Department Financial Analysis Division, Illinois Commerce Commission (Staff Ex. 2.0, Staff Ex. 7.0); Janis Freetly, Senior Financial Analyst, Finance Department, Financial Analysis Division, Illinois Commerce Commission (Staff Ex. 3.0, Staff Ex. 8.0); William R. Johnson, Economic Analyst, Rates Department, Financial Analysis Division, Illinois Commerce Commission (Staff Ex. 4.0, Staff Ex. 9.0), Brett Seagle, Gas Engineer, Energy Engineering Program, Safety and Reliability Division, Illinois Commerce Commission (Staff Ex. 5.0, Staff Ex. 10.0).

The AG's witnesses were: David J. Effron, Consultant (AG Ex. 1.0, AG Ex. 7.0); David E. Dismukes, PH.D., Consulting Economist, Acadian Consulting Group (AG Ex. 2.0 Corrected ("C"), AG Ex. 8.0); Roger D. Colton, Principal, Fisher Sheehan & Colton, Public Finance and General Economics (AG Ex. 4.0C, AG Ex. 10.0); Sarah Pickett, Administrative Assistant, Center for the Advancement of Science Education, Museum of Science and Industry (AG Ex. 5.0); Nathaniel Doromal, a software engineer in the finance industry (AG Ex. 6.0).

AG-ELPC's witness was: Scott J. Rubin, Consultant (AG/ELPC Ex. 3.0, AG/ELPC Ex. 9.0).

IIEC's witnesses were: Brian C. Collins, Consultant and Associate, Brubaker & Associates, Inc. (IIEC Ex. 1.0, IIEC Ex. 3.0); Amanda M. Alderson, Consultant, Brubaker & Associates, Inc. (IIEC Ex. 2.0).

City-CUB-IIEC's witness was: Michael P. Gorman, Consultant and Managing Principal, Brubaker & Associates, Inc. (City-CUB-IIEC Jt. Ex. 1.0, City-CUB-IIEC Jt. 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 November 10, 2014, the ALJs marked the record "Heard and Taken".

Rulings on Motions

A status hearing was held April 14, 2014, where Staff made a motion to consolidate these Dockets, as noted above. On April 14, 2014, after considering all of the parties' arguments, the ALJs entered a Protective Order for these dockets. On April 14, 2014, the ALJs issued a notice of schedule. On August 11, 2014, the ALJs granted Staff's motion to consolidate these dockets. On September 2, 2014, the ALJs denied Staff's motion to strike portions of the rebuttal testimony of Ms. Christine M. Hans and NS-PGL

Ex. 26.3. On September 10, 2014, the ALJs issued a notice of ALJ's ruling granting Staff's motion for leave to file instanter the rebuttal testimony of Daniel G. Kahle, Dianna Hathhorn, and Janis Freetly.

On September 19, 2014, the ALJs issued a notice of ALJ's ruling granting in part and denying in part the AG's motion to strike certain testimony of Utilities' witness Ms. Debra Egelhoff. On November 5, 2014, the Administrative Law Judges granted Staff's motion for administrative notice, with certain additional rulings. On November 5, 2014, the Administrative Law Judges granted the AG's October 30th motion.

Post-Hearing Briefs

On October 21, 2014, the Utilities, Staff, the AG, City-CUB, City-CUB-IIEC, ELPC, and IIEC, each filed Initial Briefs ("Init. Br." or "IB"). On November 6, 2014, the Utilities, Staff, the AG, City-CUB, City-CUB-IIEC, ELPC, and IIEC each filed Reply Briefs ("Rep. Br." or "RB"). On November 7, 2014, per direction of the ALJs, the Utilities submitted a draft Proposed Order.

On December 5, 2014, the ALJs issued their Proposed Order. On December 16, 2014, Briefs on Exceptions ("BOE") were filed by the Utilities, Staff, the AG, City-CUB-IIEC, ELPC, and IIEC. On December 23, 2014, Reply Briefs on Exceptions ("RBOE") were filed by Utilities, Staff, the AG, City-CUB-IIEC, and ELPC. This Order considers all of the positions and arguments set out in the briefs on exceptions and reply briefs on exceptions listed above.

II. TEST YEAR (UNCONTESTED)

The Utilities proposed calendar year 2015, the twelve months ending December 31, 2015, as the test year. NS Ex. 6.0 at 5; PGL Ex. 6.0 at 5. The Utilities submitted evidence that the forecasted 2015 test year data were based on careful analyses and appropriate adjustments. NS Ex. 5.0 at 4-5; NS Ex. 6.0 at 5; PGL Ex. 5.0 REV at 4-5; PGL Ex. 6.0 at 5. The proposed test year is reasonable NS Ex. 6.0 at 2; PGL Ex. 6.0 at 2, is uncontested, and is approved.

III. REVENUE REQUIREMENT

A. North Shore

Companies' Position

North Shore's final proposed base rate revenue requirement (as revised in its rebuttal testimony) is $88,181,000, or $89,778,000 if costs recovered as Other Revenues ($1,597,000) are included, and North Shore states that its proposed revenue requirement is just and reasonable based on the testimony and other exhibits in evidence. *e.g.*, NS-PGL Ex. 21.0 at 3; NS PGL Ex. 36.0 at 3, fn. 1; NS-PGL Ex. 21.1N, lines 1, 5, 10, and 11, column ("col.")[G].

At each of the direct and rebuttal testimony stages, North Shore presented pie charts and additional information showing the drivers of the net changes in their distribution costs of service and revenues forecasted for 2015 versus the levels expected in 2015 under the rates approved in the Companies' 2012 rate cases. NS-PGL IB at 10.

<u>Staff's Position</u>

The revenue requirement schedules attached to Staff's Initial Brief use the Peoples Gas' surrebuttal revenue requirement, and North Shore's rebuttal revenue requirement, as their starting point. To the extent that Staff's proposed adjustments were rejected or only partially accepted by the Companies and reflected in the Companies surrebuttal revenue requirement, Staff's proposed adjustments are shown either in total or in part as an adjustment to the Companies' surrebuttal revenue requirement. Staff's proposed adjustments that were accepted in total by the Companies and therefore are reflected in the Companies' surrebuttal position are not shown as an adjustment on Staff's Initial Brief Revenue requirement schedules.

Staff recommends a revenue requirement of $86,798,000 as reflected on page 1 of Appendix A to Staff's Initial Brief. Staff recommends an increase to base rates of $3,460,000 and an increase of $84,000 to other revenues for a total increase of $3,544,000 (4.26%). Staff's overall recommended increase is $2,980,000 less than the $6,524,000 increase requested by North Shore in rebuttal.

<u>AG's Position</u>

Notwithstanding their objection to the uncertainty of the 2015 test year as described in part III.C below, the AG recommends reducing the proposed revenue requirement (see NS-PGL Ex. 36.0 at 3:56) of North Shore Gas by $7.506 million, as shown at AG Exhibit 7.1, page 1 (Schedule DJE NS A) at the bottom of the "AG Proposed Adjustments" column. This proposed adjustment is not meant to oppose (or support) any adjustment proposals offered by other parties in this proceeding on which the AG has not commented.

More generally the AG questions the propriety and need of a rate increase for either Company. As it considers the Companies' claims that they require significant rate increases, the Commission typically assesses the claimed needs of shareholders within the context of rate of return evaluation. The rate-making process under the Act, *i.e.*, the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. *Citizens Utility Board v. Illinois Commerce Comm'n*, 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995); *citing Camelot Utilities, Inc. v. Illinois Commerce Comm'n,* 51 Ill.App.3d 5, 10, 365 N.E.2d 312 (1977). In the landmark case *Bluefield Waterworks Improvement Co. v. Public Service Comm'n of West Virginia,* 262 U.S. 279 (1923), the U.S. Supreme Court established that a utility's rates should reflect the opportunity – not a guarantee – to earn a return on its used and useful property when a commission sets rates. The *Bluefield* Court further held that a utility has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. *Id.* The Court specified that the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be 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. *Id.* at 693. Investors holding interests in regulated public utilities understand that these companies are dedicated to serving the public and therefore, the investors' possible returns may be limited. *Id.* at 692-693.

Illinois courts have adopted the *Bluefield* standards and applied them to the regulation of utilities in Illinois: "'The rate making process under the act, *i.e.*, the fixing of just and reasonable rates[,] involves a balancing of the investor and the consumer interests.'" *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n* (1953), 414 Ill. 275, 287, 111 N.E.2d 329, quoting *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944). Similarly, the Illinois Supreme Court earlier established that a just and reasonable rate must be less than the value of the service to consumers. *State Public Utilities Comm'n ex rel. City of Springfield v. Springfield Gas & Electric Co*., 291 Ill. 209, 216, 125 N.E. 891 (1919). The Appellate Court elaborated on this pronouncement in *Camelot Utilities, Inc. v. Illinois Commerce Comm'n*, 51 Ill.App.3d 5, 10, 365 N.E.2d 312 (1977), wherein the Court declared that it is the ratepayers' interest which must come first:

> The Commission has the responsibility of balancing the right of the utility's investors to a fair rate of return against the right of the public that it pay no more than the reasonable value of the utility's services. While the rates allowed can never be so low as to be confiscatory, within this outer boundary, if the rightful expectations of the investor are not compatible with those of the consuming public, it is the latter which must prevail.

Camelot Utilities, 51 Ill.App.3d at 10; *Citizens Utility Board v. Illinois Commerce Comm'n,* 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995).

As it balances the interests of Integrys Energy Group, Inc.'s ("Integrys") shareholders and the Companies' customers in this rate case, the Commission must consider the financial well-being of the customers these monopoly companies serve – just as it considers the claimed earnings requirements of investors. In so doing, the Commission should be mindful of the economic challenges facing low-income populations residing in the Companies' respective service territories. AG witness Roger Colton presents a thorough and detailed analysis demonstrating that a substantial proportion of Chicago-area ratepayers cannot afford to pay their natural gas bills even under current rates, let alone under the massive rate increases being proposed by the North Shore and Peoples utilities.

For example, the City of Chicago, which represents the entirety of Peoples' service territory, has 270,000 of its residents, or 10% of the City's population, living on income that is less than 50% of the Federal Poverty Level. More than 20% of the City's population lives at or below the Federal Poverty Level, while more than a third live on income below 150% of the Federal Poverty Level. Nearly half of all Chicago residents live with income below 200% of the Federal Poverty Level. AG Ex. 4.0 at 23-24.

Similarly, North Shore's service area has 80,000 people living at or below 200% of the Federal Poverty Level. Nearly as many people are in extreme poverty, below 50% of the Federal Poverty Level, (12,513) as live at the upper range of this population (13,217 between 175% and 200% of Federal Poverty Level). Nearly 30,000 people live below 100% of the Federal Poverty Level. Of all people in the North shore service territory, 14% live with income below 200% of the Federal Poverty Level. AG Ex. 4.0 at 24-25.

Unfortunately, the huge burden that these rate increase proposals could impose on North Shore and Peoples residential customer bases is not limited to those falling under official poverty definitions. Colton's testimony documents a "self-sufficiency income" standard for Chicago area households, using the self-sufficiency standards that were developed for Illinois by the Center for Women's Welfare at the University of Washington, based on periodic data-based analysis of the low-income and working populations throughout Illinois. AG Ex. 4.0 at 19. The self-sufficiency standard defines the level of income needed to maintain a minimum level of living without assistance. A person living on a self-sufficiency income does not live comfortably: he has no savings, spends nothing on recreation, does not make capital repairs to his housing or transportation and buys nothing on credit. While the 2014 Poverty Level for a three-person household is nearly $19,800 *per* year, the self-sufficiency standard is closer to $60,000 *per* year. So a person could have income three times the Federal Poverty Level, and still have inadequate income to be self-sufficient. AG Ex. 4.0 at 22-23. In 2009, the year in which the first self-sufficiency study was prepared for Illinois, the self-sufficiency wage ranged from a low of $23.97 *per* hour (West Side of Chicago) to a high of $29.31 *per* hour (DuPage County). The geographic area making up the North Shore and Peoples services territories have the highest self-sufficiency standards in the state of Illinois, *i.e.*, it takes more money to live a "no-frills" existence in these areas than anywhere else in the state. AG Ex. 4.0 at 22; AG Ex. 4.1, Schedule RDC-8.

The great difficulty which many people will face if the proposed rate increases and rate designs are approved is shown on Schedule RDC-12 of AG Ex. 4.1. With the median income in Chicago (below which level 50% of the population lives) at $47,653, at least 50% of Chicago's population lives below the self-sufficiency income for the North Side ($61,871), the West Side ($56,137) and the South Side ($56,267). AG Ex. 4.0 at 27. In the North Shore service territory, with the exception of one community, the median income for the lowest 20% of the population is not high enough to meet that region's self-sufficiency standard. In four of North Shore's communities the median income for the second lowest 20% of the population is a mere $30,000, and in five more North Shore communities the median income is between $30,000 and $50,000, well below the self-sufficiency standard. AG Ex. 4.0 at 28.

Given the harsh realities of the economic circumstances under which so many of North Shore and Peoples ratepayers live, it is hard to escape Colton's conclusion that a substantial number of these utility consumers cannot afford to pay their natural gas bills even under current rates. AG Ex. 4.0 at 28. Increasing rates pursuant to the North Shore/Peoples plan will make the unaffordability of natural gas delivery service not just a monthly risk but an inescapable reality for even more of these ratepayers.

Finally, Colton's examination of the North Shore/Peoples rate proposal impacts on low-use customers evaluated the risks facing Integrys relative to the burdens and risks facing customers described above. In order to examine whether the utilities had made an attempt to balance the interests of ratepayers and investors, during discovery in this proceeding the AG asked both North Shore and Peoples to provide the Attorney General's Office with each presentation or written materials provided as part of an agenda item made to the Integrys, North Shore or Peoples Board of Directors regarding low-income issues. The response provided by the utilities was that no such presentations, agenda items or materials existed. AG Ex. 4.0 at 29-30. Additionally, the AG asked the utilities to provide a copy of each presentation or agenda materials presented to the Integrys, North Shore or Peoples Board of Directors on customer service, credit or collection issues. The answer was the same: no such materials existed. AG Ex. 4.0 at 30. The financial risks facing its customers do not appear to have played a significant role in the utilities preparation of these rate increase requests.

Statements made by Integrys, the parent company of North Shore and Peoples, to the investment community, however, show considerable attention was given to the financial risks facing the companies and their investors. Company witness Moul stated that he did not engage in a balancing of interests in setting his common equity return recommendation, explaining that he considered only "investors" assessment of overall risk," which, he stated, includes "business risk" and "financial risk." AG Ex. 4.0 at 30, citing PGL Ex. 3.0 at 3, 7. Moul further testified that both utilities are riskier because they are smaller, have high operating ratios, have greater variability in earned returns and have experienced a decline in internally-generated funds, AG Ex. 4.0 at 31, citing PGL Ex. 3.0 at 8-10, and therefore a higher equity return would be justified. AG Ex. 4.0 at 31, citing NSG Ex. 3.0 at 13 and PGL Ex. 3.0 at 13.

Despite these risks, Integrys recently told investors that the company could increase its consolidated earnings in the range of 4% to 6% *per* year on an average annualized basis "for the foreseeable future." AG Ex. 4.0 at 31. Increases in the price of propane and supply shortages have accelerated natural gas conversions through the respective utility service territories. *Id.* In the Fourth Quarter 2013 Earnings conference call, one Integrys executive reported that "fourth quarter and full year 2013 consolidated financial results were at the higher end of expectations we set in our third quarter earnings conference call last November and were significantly better than our financial results for the same periods in 2012. Our utilities performed well and continue to be the core of our earnings." AG Ex. 4.0 at 32. Integrys good performance was reported to be "based solely on our strong utility growth" as "regulated businesses are our core…and provide the vast majority of our earning and our growth." AG Ex. 4.0 at 32.

Colton's examination of Integrys' own assessment of its utility companies' financial performance leads him to conclude that there has been no attempt to balance ratepayer interests against the optimistic projections of growth and prosperity offered for North Shore and Peoples. AG Ex. 4.0 at 33. If the Companies have failed to balance their need for a fifth rate increase in six years against the needs of their struggling ratepayers, then the Commission must perform that balancing itself.

Commission Analysis and Conclusion

Upon a thorough review of the record, the Commission finds that the appropriate revenue requirement for North Shore is $86,955,000. The Commission is cognizant of the need to balance the interests of rate payers entitled to fair and reasonable rates with the financial requirements of the Companies. The Commission concludes that the adjustments to the revenue requirement reflected in this Order are supported by the evidence.

B. Peoples Gas

Companies' Position

Peoples Gas' final proposed base rate revenue requirement (as revised in its rebuttal testimony and slightly reduced in its surrebuttal testimony) is $680,801,000, or $697,407,000 if costs recovered as Other Revenues ($16,606,000) are included, and Peoples Gas states that its revenue requirement is just and reasonable based on the testimony and other exhibits in evidence. *E.g.*, NS-PGL Ex. 36.0 at 3; NS-PGL Ex. 36.1P, lines 1, 4, 9, and 10, col. [G].

At each of the direct and rebuttal testimony stages, Peoples Gas presented pie charts and additional information showing the drivers of the net changes in their distribution costs of service and revenues forecasted for 2015 versus the levels expected in 2015 under the rates approved in the Utilities' 2012 rate cases. The Peoples Gas rebuttal information was not significantly changed by the surrebuttal revenue requirement reduction. NS-PGL IB at 12.

Staff's Position

Staff recommends a revenue requirement of $667,945,000 as reflected on page 1 of Appendix B to Staff's Initial Brief. Staff recommends an increase to base rates of $69,405,000 and an increase of $1,674,000 to other revenues for a total increase of $71,079,000 (11.91%). Staff's overall recommended increase is $29,462,000 less than the $100,541,000 increase requested by Peoples Gas in surrebuttal.

AG's Position

Notwithstanding their objection to the uncertainty of the 2015 test year as described in part III.C below, the AG recommends reducing the proposed revenue requirement (see NS-PGL Ex. 36.0 at 3:56) of Peoples Gas by $56.728 million, as shown at AG Exhibit 7.2, page 1 (Schedule DJE PGL A) at the bottom of the "AG Proposed Adjustments" column. This proposed adjustment is not meant to oppose (or support) any adjustment proposals offered by other parties in this proceeding that the AG has not commented on.

Commission Analysis and Conclusion

The Commission finds that the appropriate revenue requirement for Peoples Gas is $671,631,000. As the Commission acknowledged in the preceding section of this Order, it is very cognizant of the need to balance the interests of ratepayers entitled to fair and reasonable rates with the financial requirements of the Companies. The Commission concludes that the adjustments to the revenue requirement reflected in this Order are supported by the evidence.

C. Proposed Reorganization

Companies' Position

The Utilities note that the proposed acquisition by Wisconsin Energy Corporation ("WEC") of the ultimate parent company of the Utilities, Integrys, is pending before the Commission in Docket No. 14-0496. That is the proper forum for any proposals relating to whether, or on what terms, the reorganization should be approved. 220 ILCS 5/7 204. NS-PGL IB at 13.

The Utilities and Staff agree that no adjustment to the Utilities' revenue requirements is warranted by the reorganization, provided that Staff proposes one very minor change to one amortization period, as discussed in Section V.C.4 of this Order. The Utilities emphasize that there is no proposal by Staff or any intervenor, nor any basis in the evidence in the record, for any revenue requirement adjustments or other changes to the Utilities' proposals in the instant cases based on the proposed reorganization, and Staff agrees, with that minor exception. The Utilities add that the AG is trying to use the proposed reorganization as secondary support for some of its proposed adjustments, and that CCI, which presented no evidence on this subject, for the first time in its Initial Brief, made proposals relating to the proposed reorganization, but those proposals relate to the reorganization as such and are not proposed adjustments to the Utilities' revenue requirements. NS-PGL IB at 15-16; NS PGL RB at 13-16.

AG witness David Effron noted the June 23, 2014 announcement of the proposed WEC Integrys transaction, which referred in part to anticipated "operational and financial benefits". AG Ex. 1.0 at 4-5. Mr. Effron did not point to anything in the merger announcement (or any other information) that identified any specific potential benefits that would or might result in net savings by the Utilities in relation to their distribution costs of service in 2015 (or at any specific time). In fact, he went on to state in part: "It is unclear the extent to which the Companies' costs of service will be affected by the 'operational and financial benefits' referenced in the merger announcement or the extent to which these benefits should be incorporated into the determination of the Companies revenue requirements and rates. The Companies should describe and quantify the expected operational and financial benefits of the proposed merger in their Rebuttal testimony and should explain why it would or would not be appropriate to incorporate those expected operational and financial benefits into the determination of their test year revenue requirements." *Id.* at 5.

Again, while no adjustments have been proposed based on the proposed transaction, the Utilities state that the evidence would not support any adjustment, in any event. In rebuttal testimony, the Utilities stated in part:

> The proposed transaction is the acquisition of the ultimate parent company of the Utilities, Integrys Energy Group, Inc., by Wisconsin Energy Corporation ("WEC"). The Utilities are not being directly acquired by WEC. The proposed transaction is subject to approval by the Commission and several other state and federal governmental entities. Whether all of the required approvals will be received is unknown. With respect to Illinois, the application for approval that must be filed with the Commission under Section 7-204 of the Public Utilities Act has not yet been filed. In addition, it is possible that future regulatory approvals, if obtained, will be subject to conditions. Thus, whether the transaction will close, whether it will be subject to conditions, the substance of the

> conditions, if any, and when the transaction will close are unknown.

NS-PGL Ex. 17.0 at 10.

The Utilities point out that Staff agrees that no revenue requirement adjustments should be made based on the proposed reorganization (subject to the minor amortization item noted earlier). In rebuttal testimony, Staff discussed materials that were filed in Docket No. 14-0496 as well as data request responses of the Utilities in the instant cases relating to the proposed reorganization. Staff Ex. 6.0 at 23-25 and Attachment B. Staff witness Dianna Hathhorn concluded, based on her analysis, as follows:

> Q. Is it reasonable that the Companies' 2015 test years do not reflect future costs savings for the Reorganization?
>
> A. Yes, in light of the fact that the Reorganization is not guaranteed and even if it is approved, the conditions and timing of its approval cannot be known, it is reasonable that future cost savings are not reflected in this rate proceeding. In addition, based on the information provided by the Companies as to their current expectations with respect to the Reorganization, it is also reasonable that the Companies' 2015 test years do not reflect future cost savings from the Reorganization due to the expected timing of the closing of the Reorganization and Integrys' expectation of savings and shareholder benefits to earnings occurring outside of the test year.

Id. at 24- 25.

The Utilities note that Ms. Hathhorn added that, under some circumstances, if savings were realized sooner than expected, it is her understanding that the Commission could investigate and enter a temporary order fixing a temporary schedule of rates (under 220 ILCS 5/9 202), and that the Commission could condition its approval of the reorganization on a sharing of savings or other conditions (under 220 ILCS 5/7 204). Staff Ex. 6.0 at 25. The Utilities argue that those legal points are not pending and need not be briefed here, but, without discussing specifics of the scope of the Commission's authority and the procedures through which and grounds upon which it may act, it is correct that the Act contains provisions regarding interim rate orders (220 ILCS 5/9 202) and conditions upon approvals of a reorganization (220 ILCS 5/7 204). NS-PGL IB at 15; NS-PGL RB at 17-18.

The Utilities note that Staff also has pointed out that the Utilities are not proposing to include in their costs of service in these cases the acquisition premium or costs incurred to approve the reorganization, even though such costs would be incurred in 2015, the test year, if the reorganization is approved. Staff IB at 5. In addition, the Utilities note that Staff explained that the Act contains not only provisions for conditions upon approvals of a reorganization (220 ILCS 5/7 204), but also provisions regarding interim rate orders (220 ILCS 5/9 202) and requests for investigations of rates (220 ILCS 5/9 250), which could address the hypothetical situation of net costs savings occurring after the reorganization closes. Staff IB at 4 7.

The Utilities point out that AG witness Mr. Effron, in his rebuttal, speculated that the proposed reorganization might lead to cost savings, but that he neither proposed, nor presented facts supporting, any adjustment to the Utilities' revenue requirements based on the proposed reorganization, except that, in relation to his proposed adjustments to Integrys Customer Experience ("ICE") project costs, he speculated that the proposed reorganization, if approved, might lead to cancellation of the ICE project. *See* AG Ex. 7.0 at 22-25; NS-PGL IB at 7; NS-PGL RB at 14. In addition, the Utilities note that Mr. Effron offered conjecture that the proposed reorganization might lead to lower overall costs, and that the AG in briefing added the argument that the reorganization might also indirectly support his proposed adjustments to the Utilities' employee levels. The Utilities argue that the AG's speculation lacks any valid factual basis, and that any such issues belong in the other Docket.

The Utilities state that their witness Mr. Derricks in his surrebuttal: (1) discussed Ms. Hathhorn's rebuttal testimony, largely agreeing with it; (2) pointed out that Mr. Effron's rebuttal testimony's speculation is speculation, as also shown by several data request responses of Mr. Effron; (3) pointed out that Mr. Effron's rebuttal's speculation does not make sense given the timeline of the proposed reorganization and other facts, *e.g.*, that the transaction, if approved, is not expected to close until Summer 2015; and, moreover, (4) noted that speculation about hypothetical future cost reductions that might offset the needed rate increases is unwarranted, because the reality is that Peoples Gas is experiencing a significant increase in paving costs that is not reflected in its proposed revenue requirement. NS-PGL Ex. 33.0 at 5-8; NS-PGL Ex. 33.1. *See also* NS-PGL Cross Ex. 3 (additional data request responses of Mr. Effron); NS-PGL Ex. 38.0 at 8; NS-PGL Ex. 38.2 (regarding Peoples Gas' paving costs, showing they are almost $8 million over the forecast for the first eight months of 2014).

The Utilities state that, for example, Mr. Effron admitted that he did not review any information from past transactions regarding the amount of time that elapses between when a transaction closes and when a net decrease in expenses, if any, first occurred. NS-PGL Ex. 33.0, 6:129 – 7:149 (citing and quoting data request responses of Mr. Effron).

The Utilities state that Mr. Effron's failure to examine when net savings occur after a transaction (if they do) is even more problematic than the above may suggest, because he also did not take into account Staff's point that the Utilities are not proposing to include in their costs of service in these cases the acquisition premium or other costs to be incurred to approve the reorganization, even though such costs would be incurred in 2015, the test year, if the reorganization is approved. Staff IB at 5. Such costs, if considered and applied here, would increase, not decrease, the Utilities' test year costs. The Utilities are not proposing to include any such costs, which would not be appropriate in the current cases, but they do note that it is well established that costs incurred to achieve savings may be recovered through rates. NS-PGL IB at 15, fn. 12.

Thus, the Utilities summarize that Mr. Effron speculated about net savings, while not analyzing any information regarding when they might occur, and while ignoring the costs that will be incurred to achieve those savings, which costs would include significant costs in 2015.

The Utilities contend that speculation is not a lawful basis for a Commission decision. *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 contend that the AG's position is inconsistent. The AG has previously, and successfully, opposed the Utilities' use of an end of year rate base in future test year rate cases, rejecting the Utilities' argument that an end of year rate base would better reflect higher levels of investment as the rates being set remain in effect after the test year, on the grounds that other cost factors may increase or decrease after the test year. *See, e.g., North Shore Gas Co./The Peoples Gas Light and Coke Co.*, Docket Nos. 12-0511/12-0512 (Consol.), Order at 26 (June 18, 2013). However, the Utilities note that in the instant proceeding, the AG conjectures about post-reorganization net cost savings that may or may not occur, and that would not be expected to occur in 2015, while ignoring all other factors influencing the Utilities' costs of service, such as the costs of the reorganization itself, costs to achieve savings, and increased paving costs, the third of which is an already occurring known fact that is not reflected in Peoples Gas' revenue requirement. NS-PGL RB at 15-16.

The Utilities note that CCI presented no evidence on this subject and yet, CCI, in its Initial Brief (at 5), claimed that the Commission lacks sufficient information about whether the rates set in the current cases will remain appropriate under the changed conditions that may prevail after the reorganization closes in summer 2015, assuming approval of the reorganization. CCI does not oppose use of the 2015 test year. *Id.* However, CCI now proposes that the Commission in the current cases, not in the reorganization docket, impose a list of cost and revenue tracking, reporting, and filing requirements and even dividend limitations. *Id.* at 6-7.

The Utilities contend that CCI's proposals have no factual basis in the evidence, and to adopt them would be unlawful, for multiple reasons. To begin with, CCI purports to support its proposal to impose reorganization related requirements in the instant cases, rather than in the reorganization approval Docket, based on arguments that have no basis in fact or law. NS-PGL RB at 16.

The Utilities contend that those assertions come out of left field and are baseless and incorrect. 220 ILCS 5/7 204 is exactly the provision of the Act that governs the conditions that may be imposed upon approval of the proposed reorganization, and ICC Docket No. 14 0496 is the sole Docket in which the Commission is considering and can and must consider such issues. 220 ILCS 5/7 204 does not permit such issues to be litigated in multiple dockets, and to do so would cause duplicative litigation and could result in inconsistent outcomes. Moreover, Staff witness Ms. Hathhorn did not contend that any reorganization related requirements could or should be imposed in the instant cases. The opposite is true. Furthermore, CCI points to no deficiency in 220 ILCS 5/9-202 and 220 ILCS 5/9-250, which Staff has cited, and in fact CCI itself cites. CCI IB at 7.

CCI's assertion that the record in Docket No. 14-0496 "is not certain to contain sufficient evidence" has no foundation. Discovery is occurring in that Docket, as has been referenced here. *See, e.g.*, AG Cross Ex. 11. Moreover, Staff and intervenor testimony in that Docket is not even due until November 20, 2014 (and, on certain issues, not until November 26, 2014). CCI does not even attempt to claim that, much less explain why, it could not make the same proposals in the reorganization Docket. There is no factual or legal basis for imposing any reorganization related requirements in the instant cases. NS-PGL RB at 16-17.

The Utilities further contend that, in addition, and perhaps even more importantly, CCI's specific list of proposed requirements itself lacks any basis in the evidence. CCI did not make any of those proposals until CCI's Initial Brief. No other party made any such proposals. No witness supported CCI's proposals, and no witness had the chance to oppose them. There was no discovery or cross examination regarding CCI's proposals. NS-PGL RB at 17.

The Utilities contend that, thus, to approve CCI's list of proposals in the instant cases: (1) not only would contravene 220 ILCS 5/7-204; but (2) it would be contrary to the Commission's basic duty to decide these cases based on the evidence in the record and the applicable law, 220 ILCS 5/10-103; 220 ILCS 5/10-201(e)(iv)(A); and (3) it also would be contrary to due process, due to the lack of affording the Utilities notice and a fair opportunity to be heard regarding CCI's proposals, *See, e.g., Quantum Pipeline Co. v. Illinois Commerce Comm'n,* 204 Ill. App. 3d 310, 709 N.E.2d 950 (3d Dist. 1999). The due process violation would be even worse than the above discussion indicates, because it is not only the Utilities' rights that would be violated. Wisconsin Energy Corporation and four of the six other applicants in Docket No. 14-0496 are not parties to the instant cases. Their due process rights will be violated if requirements are imposed here based on the proposed reorganization. Moreover, other parties might intervene in that Docket that are not parties here, and, if so, their due process rights will be violated as well. NS-PGL RB at 17-18.

Finally, the Utilities contend that CCI's proposals lack merit even on their face. Several of the proposals involve cost and revenue and other information tracking and reporting, but CCI does not discuss any of the Utilities' existing obligations, such as their duty to file an annual ICC Form 21, and, again, CCI does not explain why the reorganization Docket could not handle any valid concerns on this subject. CCI goes even farther, urging the Commission to order the Utilities to file new rate cases by a date certain or defined in relation to the reorganization. Here, too, CCI does not explain why any concerns could not be handled in the reorganization Docket and/or under Sections 9-202 and 9-250. Moreover, the Utilities have a legal right to determine when they will file rate cases, *Lowden v. Illinois Commerce Comm'n*, 376 Ill. 225, 231, 33 N.E.2d 430, 434 (1941), so it is only under Section 7-204 in the reorganization Docket, as a possible condition of approval, that the Commission could address such a proposal, although, again, the Commission also would have Sections 9-202 and 9-250 available as measures to investigate and change rates. CCI goes still farther, by urging the Commission to limit post-reorganization dividends, which is a breathtakingly irresponsible proposal with no factual or legal basis, and which would be an additional due process violation in its own right by directly affecting the rights of investors with no notice or opportunity to be heard. CCI's proposals must be rejected.

The test year in this case is 2015. The Utilities contend that there is nothing in the record that supports any suggestion that the proposed reorganization might lead to net savings in 2015. The evidence is to the contrary. Moreover, any such issue belongs in the reorganization Docket.

The Utilities argue that the proposed reorganization, in terms of approval and possible conditions, is not a part of the instant cases, is not a basis for any adjustment in the instant cases, and must and will be addressed in Docket No. 14 0496, not here. The AG's conjectures and CCI's proposals must be rejected. NS-PGL IB at 13; NS-PGL RB at 19.

Staff's Position

Section 9-201(c) of the PUA provides in part that "[i]f the Commission enters upon a hearing concerning the propriety of any proposed rate or other charge, classification, contract, practice, rule or regulation, the Commission shall establish the rates or other charges, classifications, contracts, practices, rules or regulations proposed, in whole or in part, or others in lieu thereof, which it shall find to be just and reasonable." 220 ILCS 5/9-201(c). Based on the circumstances of the proposed merger and this proceeding's record described below, it is reasonable that (i) the Companies did not provide any information in this docket about future cost savings regarding the proposed merger and possible acquisition of the ultimate parent company of the Companies, Integrys by WEC ("Reorganization"); and (ii) the Companies' proposed rates, which are based upon 2015 test years, do not reflect future costs savings of the Reorganization. Staff Ex. 6.0 at 24-25. In Staff's view, because the Reorganization is not guaranteed, and even if it is approved, the conditions and timing of its approval cannot be known; it is reasonable that future cost savings are not reflected in this rate proceeding.

The AG recommended that the Companies describe and quantify the expected operational and financial benefits of the Reorganization. AG Ex. 1.0 at 4-5. Companies' witness Derricks responded generally that the Reorganization is subject to future regulatory approvals, and the conditions and timing are unknown. NS-PGL Ex. 17.0 at 10. Since the filing of the Companies' rebuttal testimony, the Companies filed their Application for the Reorganization in Docket No. 14-0496. The Companies' responses to discovery concerning the Reorganization's effect on the 2015 test year revenue requirement are included in Attachment B to Staff Ex. 6.0.

Staff witness Hathhorn testified concerning the timing of the pending rate cases with the Reorganization and whether it was reasonable that the Companies' proposed rates do not reflect future costs savings from the Reorganization. Staff Ex. 6.0 at 24. In the Fact Sheet filed in Docket No. 14-0496, as part of the filing requirements under Section 7-204A(a)(2)(ii) (Staff Ex. 6.0, Attachment B), Integrys states that the expected closing of the transaction is summer 2015. The Companies are not requesting cost recovery of the acquisition premium, *i.e.*, the price above book value, or the costs incurred to accomplish the Reorganization (Docket No. 14-0496, Petition at 13), although these costs are expected to be incurred within the 2015 test year. The Reorganization is expected to have potential long-term synergy savings. (Attachment B.) The Fact Sheet states further that the combination is accretive to earnings *per* share in the first full calendar year after closing, likely 2016 based on the expected closing date.

In light of the fact that the Reorganization is not guaranteed, and even if it is approved, the conditions and timing of its approval cannot be known, it is reasonable that future cost savings are not reflected in this rate proceeding. In addition, based on the information provided by the Companies as to their current expectations with respect to the Reorganization, it is also reasonable that the Companies' 2015 test years do not reflect future cost savings from the Reorganization due to the expected timing of the closing of the Reorganization and Integrys' expectation of savings and shareholder benefits to earnings occurring outside of the test year. Staff Ex. 6.0 at 24. Under some circumstances, however, if the Reorganization is approved and savings are realized sooner than expected, the rates derived from this proceeding may need to be adjusted. 220 ILCS 5/9-250. Further, should information become known that would materially change these expectations, the Commission has the authority to investigate the Companies' rates and/or enter a temporary order fixing a temporary schedule of rates under Article 9 and to condition its approval of the Reorganization on the appropriate sharing of savings or to require compliance with other conditions to reflect the Reorganization's impact on rates. 220 ILCS 5/9-202.

Finally, based on the information provided by the Companies in this proceeding, Staff's finance expert witness, Janis Freetly, testified that there is no need to adjust Staff's recommended rate of return on rate base due to WEC's proposed acquisition of Integrys. At this time, it is unknown if the reorganization will occur and if so, how the reorganization will affect the Companies' rate of return. Staff Ex. 8.0 at 21. Should information become known that would materially change the rate of return on rate base, however, the Commission has the authority to investigate the Companies' rates under Article 9 as discussed above, and to condition its approval of the reorganization on a revised rate of return on rate base should the merger impact that set in this proceeding pursuant to Section 5/7-204(f) of the PUA. *Id.*

AG's Position

As AG witness David Effron noted in direct testimony, the recently (June 23, 2014) announced acquisition agreement between Integrys – the parent of North Shore and Peoples Gas – by Wisconsin Energy Corp makes reference to "operational and financial benefits" that are "clear, achievable and compelling" and states that the transaction will be "accretive to Wisconsin Energy's earnings *per* share in the first full calendar year after closing." AG Ex. 1.0 at 4-5. The anticipated closing for the merger is the summer of 2015, which is the middle of the future test year in this proceeding. The extent to which the Companies' costs of service will be affected by the "operational and financial benefits" referenced in the merger announcement, or the extent to which these benefits should be incorporated into the determination of the Companies' 2015 revenue requirement in this proceeding, is completely unclear. *Id.* at 5. The lack of clarity around North Shore's and People's future should raise the question of whether the notion of deciding a 2015 revenue requirement in this proceeding is even coherent.

Mr. Effron advised in direct testimony that "[t]he Companies should describe and quantify the expected operational and financial benefits of the proposed merger in their Rebuttal testimony and should explain why it would or would not be appropriate to incorporate those expected operational and financial benefits into the determination of their test-year revenue requirements." *Id.* at 5. Rather than complying with Mr. Effron's suggestion, the Companies only cited uncertainties regarding the scheduled July 2015 closing of the proposed transaction in their rebuttal testimony and in discovery responses. *See, e.g.*, NS-PGL Ex. 17.0, at 10 ("[t]he proposed transaction is subject to approval by the Commission and several other state and federal governmental entities. Whether all of the required approvals will be received is unknown. In addition, it is possible that future regulatory approvals, if obtained, will be subject to conditions"); *see also* Staff Ex. 6.0, Attachment B, PGL response to Staff data request DGK 30.01 ("there are too many uncertainties for the Utilities to have an expectation regarding this subject"). In light of the numerous uncertainties around the pending merger, it is thus difficult to understand how the Commission can set a test-year revenue requirement based on 2015 expenses. Mr. Effron advised in rebuttal testimony that:

> [g]iven that mergers and acquisitions frequently result in decreases to expenses, the expense increases being forecasted by the Companies seem especially speculative in the circumstances, as the merger should enable the Companies to, at a minimum, avoid such increases. . . . The merger is forecasted to close in the summer of 2015. The inability or unwillingness of the Companies to quantify the operational and financial benefits calls into question the reliability of the forecasted costs for 2015, the test year in this case and the first year that the rates established in this case will be in effect. It is entirely possible that the merger will generate cost savings well beyond the mitigation of the expense increases that I have addressed. In effect, the Companies are asking the Commission to base rates on costs that may not comport with the post-merger reality. Given the uncertain effects of the merger, the Commission should question whether any rate changes are appropriate at this time.

AG Ex. 7.0 at 24-25. The AG echoes Mr. Effron's suggestions in urging the Commission to consider whether there should be any rate changes at this time of great uncertainty for 2015.

<u>CCI's Position</u>

The Companies have asked the Commission to approve proposed rate increases based on a 2015 Test Year. The 2015 Test Year is presented as representative of the period the rates determined in this case will be in effect. *See*, *e.g.*, PGL Ex. 5.0 at 2. The rates set in this proceeding will remain in effect until NS-PGL elects to file another rate case, or until the Commission orders an examination of NS-PGL's rates for other reasons. Currently, the Companies are under no obligation to resubmit their comprehensive costs and revenues for regulatory scrutiny within a definite period.2 In the past, the Companies' rates have remained unreviewed in a rate proceeding for as long as a dozen years (between Dockett No. 95-0032 and Docket Nos. 07-0241/02422 (Consol.).

At the same time, the Companies are also applicants seeking Commission approval of the acquisition of NS-PGL's parent company (and indirectly of the Companies) by a Wisconsin utility holding company. NS-PGL Ex. 17.0 at 10. If approved, the proposed reorganization would close in the middle of the 2015 Test Year being used in this case to set rates. NS-PGL Ex. 33.0 at 7. The effects of the reorganization (if approved) on the Companies' costs of service are unknown. Indeed, the potential changes to NS-PGL's costs of service are not addressed in this proceeding. The Companies avow a near-total lack of knowledge about potential changes in the Companies' costs of service. They suggest that it is possible that future regulatory approvals, if obtained, will be subject to conditions. NS-PGL Ex. 33.0 at 3. "[W]hether the transaction will close, whether it will be subject to conditions, the substance of the conditions, if any, and when the transaction will close are unknown." *Id.*

There can be no doubt the transaction, if it closes in 2015, will have some effect on the Companies' costs during the 2015 test year and going forward, effects that are not considered in this rate proceeding. Predictably, intervenors in this case (non-parties to the proposed reorganization transactions) have even less access to information about plans for, and the costs of, integrating affected entities, systems, and operations.

As a result, the Commission lacks adequate information to reach an informed conclusion about whether rates determined on a (pre-reorganization) 2015 Test Year will be appropriate under the changed conditions that a reorganization would engender. The proposed reorganization may cause significant (but currently unquantified) changes in the Companies' costs of service -- in the Test Year and beyond. *See* AG Ex. 7.0 at 475-481. It is not certain that the rates approved in this proceeding will remain just and reasonable under the changed circumstances of a reorganization. See Staff Ex. 6.0 at 25 ("Staff is aware of the fact that under some circumstances, if the Reorganization is approved and savings are realized sooner than expected, the rates derived from this proceeding may need to be adjusted.")

Notwithstanding these concerns, CCI do not oppose use of the 2015 test year. However, that lack of opposition exists only because (a) no superior basis for future rates is currently available and (b) CCI expect that the Commission will use its regulatory authority to appropriately qualify its 2015 Test Year rate determinations. The 2015 Test Year in this case reflects circumstances the Companies are working actively to alter dramatically, during the Test Year. The focus of the reorganization proceeding, moreover, is structural realignment, not ratemaking, and it cannot reasonably be expected to provide a quantitative basis for tariff rate decisions. Accordingly, the Commission must act to assure timely re-examination of the Companies' rates, in the new circumstances of a reorganization the Commission may approve almost immediately after rates are fixed using pre-reorganization cost data. The Commission's Staff expert has recognized the potential for harm to ratepayers.

Coordinating Commission orders in this rate case and in the pending reorganization proceeding will be a challenge for the Commission. However, the risks or burdens of that challenge should not fall on the Companies' customers, who did not initiate either the proposed rate changes or the proposed reorganization.

To enable timely investigation of the appropriateness of the Companies' rates under the changed conditions of a reorganization, the Commission should order an appropriate combination of the following prudent actions to protect ratepayers:

- order the Companies to report any significant change in their costs of providing regulated services, and any significant change in amounts allocated to the Companies from other affiliates, so the Commission can assess the appropriateness of possible orders to show cause why NS-PGL rates should not be reduced;

- order the Companies to separately track and record all costs, whether expenses or investments, associated with the reorganization (including costs attributable to transitions to common accounting, computer, and other management systems, to mergers of organization structures, and consolidation of operations), so that the Commission can assure that costs unrelated to the Companies' provision of regulated services are not included in regulated rates;

- order the Companies to report their actual costs and revenues, with costs attributable to the reorganization excluded and separately stated, with a view to prompt investigation (through show cause proceeding or otherwise -- §§ 9-250; 9-202), if indicated, of whether the Companies' approved rates continue to be just and reasonable;

- order the Companies to file new rates by a date certain (or within a specified period after the reorganization) that reflect (through an appropriate test year) the changed conditions occasioned by the reorganization;

- order the Companies (a) to limit any post-reorganization dividend pay-outs from the Companies to any affiliates to a level representative of pre-reorganization pay-outs and (b) to report any dividend pay-outs to the Commission within 30 days of such pay-outs; and

- order the Companies to report to the Commission, within 14 days of the change, any changes by credit rating agencies to their credit ratings of, or their recommendations concerning, the Companies or any affiliates.

The Commission should not rely solely on conditions or other protective measures that may be ordered in the reorganization proceeding. *See* Staff Ex. 6.0 at 25. The Commission must act in this case, especially because the record in that case is not certain to contain sufficient evidence on ratemaking issues to support directives that fully protect the Companies' ratepayers.

<u>Commission Analysis and Conclusion</u>

The Commission agrees with Staff that the pending merger case, Docket No. 14-0496, is the more appropriate place to evaluate merger conditions and cost savings arising from the merger. Although the merger is very likely to occur, imposing conditions or requiring concrete savings commitments in another docket in advance of the acquisition is impractical and unwise.

IV. RATE BASE

A. Overview/Summary/Totals

1. North Shore

North Shore's rebuttal testimony presented an average rate base of $219,786,000, reflecting adjustments proposed by Staff and Intervenors that the utility agreed with or accepted in whole or in part and certain updates.

Staff recommends a rate base of $218,599,000 which is $1,187,000 less than the rate base requested by North Shore.

2. Peoples Gas

Peoples Gas' surrebuttal testimony presented an average rate base of $1,759,289,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part and certain updates.

Staff recommends a rate base of $1,670,732,000 which is $88,557,000 less than the $1,759,289,000 rate base requested by Peoples Gas in surrebuttal.

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

1. Gross Utility Plant

a. 2013 Plant Balances

The Companies' direct cases provided actual plant balances for 2011 and 2012, six months actual data and six months forecasted data for 2013, and forecasts for 2014 and 2015 plant balances. In response, CCI witness Mr. Gorman noted that Peoples Gas' actual distribution plant balance as of December 31, 2013, was less than the forecasted level reflected in the Companies' forecast for December 31, 2013, and recommended that the Companies develop a forecasted rate base reflecting the 2013 actual data. Mr. Gorman did not address North Shore's actual 2013 plant balances, which exceeded its forecasted 2013 balances. In rebuttal testimony, the Companies partially agreed with Mr. Gorman's recommendation, and made an adjustment to each Utility's respective net utility plant balances and Accumulated Deferred Income Taxes ("ADIT") to reflect the actual plant, accumulated depreciation and ADIT for calendar year 2013 as compared to the '6&6' forecast balances. Mr. Gorman did not further address this issue in rebuttal testimony. No witness or party contested the updated 2013 figures. The Commission approves the Companies' updated 2013 plant balances.

b. 2014 Plant Balances (other than PGL AMRP Additions and associated items addressed in Section IV.C.1.a)

The Companies provided forecasts for 2014 plant balances. In response, CCI witness Mr. Gorman and AG witness Mr. Effron presented their respective proposals to adjust the 2014 forecast (in Mr. Effron's case, focusing specifically on Accelerated Main Replacement Program ("AMRP") additions, costs of removal associated with the AMRP additions, and costs of removal associated with other plant additions). In rebuttal testimony, the Companies updated their forecasted 2014 plant balances. Mr. Gorman did not further address this issue in rebuttal testimony. In his rebuttal testimony, Mr. Effron dropped his general costs of removal adjustment, but presented revised adjustments for AMRP costs and the associated costs of removal, as discussed in Section IV.C.1.a. Staff rebuttal witness Ms. Hathhorn proposed to adopt Mr. Effron's direct testimony proposal, subject to it being updated and corrected, although she did not present testimony on the actual merits of the proposal, other than brief speculation. CCI's Initial Brief (at 8) confirmed that it was not proposing any adjustment to 2014 plant balances. Thus, apart from the 2014 AMRP costs and associated costs of removal, the Companies' 2014 plant balances as updated in rebuttal are uncontested (subject to a slight correction of Peoples Gas' figure in surrebuttal that is uncontested, discussed in Section IV.B.1.c.vii, below). The Commission approves the Companies' updated 2014 plant balances, subject to the updates discussed in Section IV.C.1.a of this Order.

c. 2015 Forecasted Capital Additions

(i) In General

The Companies provided forecasts for 2015 plant balances to be included in rate base. The forecasted 2015 plant additions (as revised in rebuttal, where applicable) are uncontested. The Commission approves the Companies' forecasts for 2015 plant balances.

The Companies noted that, pursuant to 83 Ill. Adm. Code § 285.6100, Peoples Gas identified major capital projects added to rate base since Peoples Gas 2012 as a project with a cost greater than the lower of 0.2% of net plant or $10,000,000. Peoples Gas' net plant at December 31, 2012, was $2,131,077,763, and, thus, a major project is one that costs more than $4,262,000. Peoples Gas identified six major capital projects: (1) AMRP, (2) Calumet System Upgrade Project, (3) 2015 casing remediation project, (4) 2014 Gathering System Pipe Replacement project, (5) 2015 Gathering System Pipe Replacement project, and (6) the LNG Control System Upgrade. These projects, discussed below, are uncontested as to 2015.

The Companies further noted that pursuant to 83 Ill. Adm. Code § 285.6100, North Shore identified major capital projects as a project with a cost greater than the higher of 0.2% of net plant or $1,000,000. North Shore's net plant at December 31, 2012, was $263,103,698, and, thus, a major project is one that costs more than $1,000,000. North Shore identified three major capital projects: (1) Wildwood/Gages Lake, (2) Grayslake Gate Station, and (3) Casing Remediation Program. These projects, as discussed below, are uncontested as to 2015.

2014 AMRP costs are discussed in Section IV.C.1.a of this Order. The other major capital projects are discussed below, including both 2014 and 2015 costs.

(ii) Calumet System Upgrade (PGL)

Peoples Gas has reduced its Calumet System Upgrade costs to reflect the updated cost of work that will be completed in 2014, reducing the 2014 expenditures from $43.1 million to $36.3 million. Peoples Gas noted that of this reduced amount, $15.0 million will be in service in 2014 and the remaining $21.3 million will be accounted for as construction work in progress at December 31, 2014. These costs are not contested. The Commission approves the costs associated with Peoples Gas' Calumet System Upgrade project, subject to the updates discussed in Section IV.C.1.a of this Order.

(iii) Casing Remediation (PGL)

Peoples Gas forecasted capital additions in 2014 and 2015 of $10 million for the casing remediation program. These costs are not contested. The Commission approves the costs associated with Peoples Gas' Casing Remediation project.

(iv) Gathering System Pipe Replacement Project (PGL)

Peoples Gas presented two major capital projects for 2014 and 2015: the 2014 Gathering System Pipe Replacement Project and the 2015 Gathering System Pipe Replacement Project. Peoples Gas noted that these projects exceeded the major capital project threshold of $4,262,000. Peoples Gas forecasted capital costs of $5,525,000 for the 2014 Gathering System Pipe Replacement Project, to be expended during calendar year 2014 and capital costs of $6,000,000 for the 2015 Gathering System Pipe Replacement Project, to be expended during calendar year 2015. These costs are uncontested. The Commission approves the costs associated with Peoples Gas' 2014 and 2015 Gathering System Pipe Replacement Project.

(v) LNG Control System Upgrade (PGL)

Peoples Gas forecasted capital additions for its Liquefied Natural Gas ("LNG") Control System Upgrade Project of $8,800,000, to be expended during calendar year 2014. This item was not contested. The Commission approves the costs associated with Peoples Gas' LNG Control System Upgrade Project.

(vi) LNG Truck Loading Facility (PGL)

<u>Companies' Position</u>

Peoples Gas states that it has withdrawn its proposal to develop an LNG Truck Loading Facility to be added to rate base in the 2015 test year. This issue is not contested. However, Staff requests the Commission to rule in this docket that the Companies should, prior to developing any potential LNG Truck Loading Facility or entering into any contracts related to the sale of LNG from such a facility, make a filing seeking approval under 220 ILCS 5/7-102. The Companies argue that such a ruling would be premature, as there is no LNG Truck Loading Facility proposed for consideration in front of the Commission. The Companies also maintain that there is insufficient evidence in this docket to make such a determination.

<u>Staff's Position</u>

Staff notes that in rebuttal, Peoples Gas witness Thomas Puracchio stated Peoples Gas reserves the right to construct and operate a LNG Truck Loading Facility and to seek recovery through rates in the future. Staff reiterated its recommendation that Peoples Gas receive Commission approval pursuant to Article 7 of the Act to construct and operate the LNG Truck Loading Facility in Staff Witness Mr. Seagle's rebuttal testimony. In surrebuttal, Mr. Puracchio stated the issue of what activities require Commission approval are a legal matter that Peoples Gas will address in briefs rather than in testimony.

Staff argues that Section 7-102 (A)(g) states:

> Unless the consent and approval of the Commission is first obtained or unless such approval is waived by the Commission or is exempted in accordance with the provisions of this Section or of any other Section of this Act:
>
> (g) No public utility may use, appropriate, or divert any of its moneys, property or other resources in or to any business or enterprise which is not, prior to such use, appropriation or diversion essentially and directly connected with or a proper and necessary department or division of the business of such public utility; provided that this subsection shall not be construed as modifying subsections (a) through (e) of this Section.

220 ILCS 5/7-102(A)(g). Staff argues that Section 7-102(A)(g) requires that, among other things, Companies only use their property in a manner which is directly related to the business of providing utility services. The purpose of these provisions of the Act is to assure both that ratepayers are adequately served by the utility and that the utility receives reasonable return for its services. *Village of Hillside v. Ill. Commerce Comm'n*, 111 Ill.App.3d 25 (1st Dist. 1982).

Staff argues that despite Peoples Gas' willingness to withdraw its request for cost recovery, the Commission should require Peoples Gas to seek approval pursuant to Section 7-102 of the PUA (220 ILCS 5/7-102) prior to initiating the construction of a LNG Truck Loading Facility or entering into contracts to sell LNG by means of the LNG Truck Loading Facility at its Manlove Underground Gas Storage Field.

Commission Analysis and Conclusion

Staff witness Seagle recommended the Commission reduce Peoples Gas' rate base, regarding a LNG Truck Loading Facility, by $4,000,000. In rebuttal, Peoples Gas withdrew its proposal to develop an LNG Truck Loading Facility to be added to rate base in the 2015 test year. This issue is not contested. Requiring Peoples Gas to seek approval pursuant to Section 7-102 of the Act prior to initiating the construction of a LNG Truck Loading Facility or entering into contracts to sell LNG by means of the LNG Truck Loading Facility is premature.

(vii) Reclassification of Costs to Plant in Service (PGL)

Peoples Gas noted that an adjustment to reclassify certain costs from operations and maintenance ("O&M") expenses to Plant in Service was inadvertently omitted from Peoples Gas' rebuttal revenue requirement, and updated its adjustment accordingly to reflect the reduction to O&M expense offset by derivative depreciation expense and income taxes on Plant in Service. This adjustment is uncontested. The Commission approves Peoples Gas' coordinated adjustment to rate base and O&M expenses.

(viii) Wildwood/Gages Lake (NS)

North Shore forecasted capital additions for its Wildwood/Gages Lake project of $2,400,000 for 2014 and 2015. These costs were not contested. The Commission approves the costs associated with North Shore's Wildwood/Gages Lake project.

(ix) Grayslake Gate Station (NS)

North Shore forecasted capital additions for its Grayslake Gate Station project of $6,525,000 for 2014 and 2015. These costs were not contested. The Commission approves the costs associated with North Shore's Grayslake Gate Station project.

(x) Casing Remediation (NS)

North Shore forecasted capital additions for its Casing Remediation project of $6,250,000 for 2014 and 2015. These costs were not contested. The Commission approves the costs associated with North Shore's Casing Remediation project.

(xi) Locker Room (NS)

North Shore withdrew the Locker Room project from this rate case. The calculation of the resulting plant reductions as presented in North Shore's rebuttal testimony is uncontested. The Commission approves North Shore's plant reductions for this project.

d. Original Cost Determinations as to Plant Balances as of December 31, 2012

The Companies and Staff agree to the original cost determinations of $443,539,000 for North Shore and $3,285,370,000 for Peoples Gas as of December 31, 2012. They agreed that the following language should be included in the Findings and Ordering Paragraphs of the Commission's final Order. That language is:

> It is further ordered that the $443,539,000 original cost of plant for North Shore at December 31, 2012 and the $3,285,370,000 original cost of plant for Peoples Gas at December 31, 2012, as presented in Staff Exhibit 1.0, are unconditionally approved as the original costs of plant.

The Commission approves that language, which appears in the Findings and Ordering Paragraphs, below.

2. Accumulated Provisions for Depreciation and Amortization (including new depreciation rates and including derivative impacts other than in Section IV.C.1.a)

The inclusion of Plant in Service in rate base is subject to reduction for the associated applicable Accumulated Provisions for Depreciation and Amortization. The balances for accumulated depreciation and amortization, subject to derivative impacts, if any, as presented by the Companies, are $200,691,000 for North Shore and

$1,245,048,000 for Peoples Gas, based on actual per book data and projected data as applicable. This subject is uncontested, apart from derivative impacts, if any, of the items discussed in Section IV.C.1.a below. The Commission approves the balances for accumulated depreciation and amortization, subject to derivative impacts.

The Companies note that the depreciation rates used in these cases are new rates based on a study supported by independent expert Companies witness John Spanos. The Companies explain that this reflects the Commission's past direction that the Companies prepare a new study every five years. The new rates are uncontested. The Commission approves the new depreciation rates provided by the Companies.

3. Cash Working Capital (other than Section IV.C.2)

The Companies explain that cash working capital ("CWC") is the amount of funds required to finance the day-to-day operations of a utility. The Companies note that CWC usually is calculated using a "lead/lag study", which is a study of the applicable cash flows, and that is how it has been calculated in the instant cases. The Companies note that the CWC figure is independently calculated for the test year, so it is not an average.

The final CWC calculations presented by the Companies based on their lead/lag studies as updated in rebuttal (North Shore) and surrebuttal (Peoples Gas) are $(1,721,000) for North Shore and $10,783,000 for Peoples Gas. The Companies and Staff agree on the calculation of CWC, subject to the item in the next paragraph of this Order, and agree that the final balances of CWC will be established using the applicable final inputs ultimately approved in this proceeding.

This subject is uncontested with the exception of the "expense lead" for other post employment benefits ("OPEB") expenses, discussed in Section IV.C.2.a below, and derivative impacts on the inputs to the CWC calculation, if any, of contested operating expense adjustments. Therefore, the Commission approves the final CWC calculations presented by the Companies, subject to the determination of the OPEB expense lead issue and the derivative impacts, if any, of rulings on contested issues that affect the final inputs to the CWC calculations.

4. Materials and Supplies, Net of Accounts Payable

Consistent with the Commission's Orders in the Companies' recent rate cases, the Companies presented the 13-month average balances of materials and supplies, net of accounts payable, based on actual per book data and projected data as applicable. The 13-month averages (net) for test year 2015 are $1,928,000 for North Shore and $15,302,000 for Peoples Gas. This subject is uncontested. The Commission approves the Companies' 13-month average balances of Materials and Supplies, net of accounts payable.

5. Gas in Storage

Consistent with the Commission's Orders in the Companies' recent rate cases, the Companies presented the 13-month average balances of Gas in Storage based on actual per book data and projected data as applicable. The 13-month averages for test year 2015 are $6,238,000 for North Shore and $47,405,000 for Peoples Gas. This subject is uncontested. The Commission approves the Companies' 13-month average balances of Gas in Storage.

6. Budget Plan Balances

The Companies note that Budget Plan Balances may be a component (reduction) of rate base when they provide a source of capital. The Companies presented the 13-month average balances of Budget Plan Balances based on actual per book data and projected data as applicable. The 13-month averages for test year 2015 are $831,000 for North Shore and $10,847,000 for Peoples Gas. In addition, the Companies accepted Staff's recommended adjustment to reflect the use of the Commission's ordered interest rate of 0% to be paid on customer deposits as the rate at which budget payment plan balances will accrue interest. This subject is uncontested. The Commission approves the Companies' Budget Plan Balances and the use of the interest rate of 0% to be paid on customer deposits.

7. Accumulated Deferred Income Taxes

The Companies note that inclusion of Plant in Service in rate base is subject to reduction for the applicable associated ADIT. The final ADIT balances presented by the Companies are $(79,725,000) for North Shore and $(520,978,000) for Peoples Gas, adjusted for deferred taxes associated with incentive compensation and Net Operating Losses ("NOLs"), as discussed below. This subject is uncontested with the exception of ADIT as a derivative impact of the items discussed in Sections IV.C.1.a and IV.C.3 below. The Commission approves the final ADIT balances as presented by the Companies.

a. Incentive Compensation

The Companies have agreed to remove, from rate base, the ADIT related to the capitalized incentive compensation costs previously disallowed by the Commission. This is not contested. The Commission approves removal from rate base of the ADIT related to the capitalized incentive compensation costs previously disallowed by the Commission.

b. Net Operating Losses

The Companies and Staff agree that the stand-alone federal NOLs and the related federal deferred tax assets ("DTAs") balances at the end of calendar year 2014 and test year 2015 are zero, and, therefore, the average rate bases used for the test year should not include any NOLs or DTAs. These items are not included in the Companies' rate bases. This subject is uncontested and is approved by the Commission.

c. Derivative Impacts (other than in Section IV.C.1.a)

The Companies note, and the Commission agrees, that the only contested issues related to ADIT are the derivative impacts on ADIT of the items discussed in Sections IV.C.1.a and IV.C.3 below.

8. Customer Deposits

The Companies note that Customer Deposits may be a component (reduction) of rate base when they provide a source of capital. The Companies' original projected balances of Customer Deposits were $(1,996,000) for North Shore and $(23,657,000) for Peoples Gas, based on actual per book data and projected data as applicable. In addition, the Companies accepted Staff's recommended adjustment to reflect the use of the Commission's ordered interest rate of 0% to be paid on customer deposits. This subject is uncontested. The Commission approves the Companies' Customer Deposit balances and the use of the interest rate of 0% to be paid on customer deposits.

9. Customer Advances for Construction

The Companies note that Customer Advances for Construction may be a component (reduction) of rate base when they provide a source of capital. The Companies proposed a credit balance for this item of $562,000 for North Shore and a credit balance of $1,494,000 for Peoples Gas, based on actual per book data and projected data as applicable. This subject is uncontested. The Commission approves the Companies' Customer Advances for Construction credit balances.

10. Reserve for Injuries and Damages

The Companies note that the Reserve for Injuries and Damages may be a component (reduction) of rate base when it provides a source of capital. The Companies proposed a credit balance of $1,082,000 for North Shore as the projected balance for the Reserve for Injuries and Damages at December 31, 2014, and December 31, 2015. North Shore noted that it is not projecting any amounts assumed to be reimbursed by insurance companies.

For Peoples Gas, the Companies proposed a credit balance of $7,615,000 as the projected balance at December 31, 2014, and a credit balance of $7,613,000 as the projected balance at December 31, 2015, for an average of $7,614,000. Peoples Gas noted that beginning in 2012, amounts related to claims that were expected to be reimbursed from insurance companies were recorded by increasing the reserve for injuries and damages and recording an offsetting accounts receivable from the insurance company.

This subject is uncontested. The Commission approves the credit balances for 2014 and 2015 for North Shore and for Peoples Gas.

C. Potentially Contested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Plant

a. 2014 AMRP Additions (including derivative impacts on Accumulated Depreciation and Accumulated Deferred Income Taxes) and Associated Cost of Removal (PGL)

<u>Companies' Position</u>

Peoples Gas argues that its 2014 AMRP costs and the associated costs of removal should be adopted. As background Peoples Gas explains that in fiscal year 1981, Peoples Gas decided to replace its predominantly cast iron and ductile iron main system with cathodically protected steel and plastic main. In that year, cast iron and ductile iron main represented 3,450 miles out of the total of 4,031 miles of main in Peoples Gas' distribution system, or 86%. A 1981 study recommended replacement in certain soil types by 2030, but updates to the study concluded it would be reasonable and prudent to complete all main replacement by 2050. Peoples Gas later determined, however, that acceleration of the program would be beneficial, and the Commission agreed.

In the Companies' 2009 rate cases, Docket Nos. 09-0166/09-0167 (Consol.), the Commission approved a rider that, in brief, would allow Peoples Gas to recover incremental costs of accelerating its cast iron and ductile iron main replacement program. The Commission found that the benefits of accelerating the program include increased safety for the public and Peoples Gas crews, construction and Operating and Maintenance cost savings, creation of jobs, reduction in environmental impacts, and increased functionalities. In 2013, Section 9-220.3 of the Act, 220 ILCS 5/9-220.3, was enacted to allow rider recovery of qualifying infrastructure plant, which includes (but is not limited to) accelerated main replacement costs.

Peoples Gas details that there are four main system upgrade goals for AMRP: (1) to retire 1,870 miles of cast iron/ductile iron gas distribution mains, (2) to upgrade approximately 300,000 service pipes, (3) to relocate gas meters from inside of customer facilities to outside, and (4) to upgrade the gas distribution system from a low pressure to a medium pressure system. Peoples Gas adds that it uses a Main Ranking Index ("MRI") to decide which mains to replace. The Companies state that AMRP is coordinated with the City of Chicago and has extensive management oversight. Peoples Gas notes that their primary witness related to the AMRP, David Lazzaro, is a General Manager of District Field Operations for Peoples Gas, is a highly experienced engineer, and is responsible for all gas distribution utility field operations in the Peoples Gas Central District, including customer service, distribution system maintenance, and construction.

Peoples Gas notes that the AG, in direct testimony, proposed huge reductions in the forecasted 2014 AMRP additions (including the associated costs of removal), *i.e.*, a reduction in the 2014 AMRP additions of a gross $172,651,000, plus another $27,391,000 for the associated costs of removal (the adjustments also have derivative impacts on accumulated depreciation, ADIT, and depreciation expense). According to Peoples Gas, this proposal was based on simply extrapolating from data on actual costs from January through May 2014.

Peoples Gas explains that Mr. Effron's education is in economics, business administration, and accounting. He has spent over 25 years as a regulatory consultant. Before that, he worked for two years as a "supervisor of capital investment analysis and controls" for the conglomerate Gulf & Western Industries and before that for two years as a consultant and staff auditor at an accounting firm. Peoples Gas states that Mr. Effron is not an engineer and he does not appear to have any experience managing a utility capital project or any other infrastructure project.

Peoples Gas argues that Mr. Effron's direct testimony proposal made no sense and was wrong, because, among other things, his simplistic extrapolation from the first five months of 2014 failed to take into account the effects of the unusually cold winter weather on the pace of construction, failed to take into account plans to remediate those delays, and failed to take into account the annual construction cycle, basically missing the peak construction season. According to Peoples Gas, Mr. Effron's proposal also included errors in calculating the derivative impacts (the accumulated depreciation, ADIT, and depreciation expense impacts) associated with his recommended reductions.

Peoples Gas notes that, in contrast, the Companies, in their rebuttal testimony, presented updated reduced costs of the 2014 AMRP additions (and addressed the associated costs of removal) that: (1) reflected the slowed pace of construction in the beginning of the year; (2) took into account the contractors' plans to remediate some, but not all, of the delays; and (3) factored in the construction cycle. Peoples Gas contends that these are the only reliable numbers in the evidentiary record for these costs. In addition, Peoples Gas maintains that CCI accepts the Companies' figures, as presented in rebuttal testimony, for the 2014 plant balances.

Peoples Gas argues that although Mr. Effron's rebuttal testimony significantly reduced his recommended adjustments, he continued to propose to reduce Peoples Gas' 2014 AMRP costs by a gross $65,877,000 plus another $17,231,000 for associated costs of removal (the adjustments also have derivative impacts on accumulated depreciation, ADIT, and depreciation expense). This proposal is based on simply extrapolating from data on actual costs from January through July 2014. Peoples Gas points out that as a result, the AG's rebuttal proposal does not cure the fundamental flaws of the earlier simplistic extrapolation, although the addition of two months of data to his extrapolation reduced the size of his recommended adjustment. Further, the Companies' witness noted that: (1) data for August 2014 further showed that Mr. Effron's proposal was unreasonable, *i.e.*, August 2014 AMRP expenditures were $38.5 million; and, (2) expected expenditures for the four remaining months of the year are $25 million to $30 million per month. Peoples Gas also states that, setting aside the merits of the primary proposed adjustments, the derivative adjustments Mr. Effron calculated in rebuttal were less inaccurate than those in his direct testimony proposal, but they still were incorrect. Peoples Gas mentions that Staff agrees with the Companies' corrections to the AG's calculations of the derivative impacts.

Peoples Gas notes that while the AG's briefing (like its cross-examination at the evidentiary hearing) focuses on confirming the correctness of figures for actual capital expenditures on AMRP for January through August 2014, the capital expenditure "actuals" do not support the AG's proposals. Peoples Gas emphasizes that the numbers it presented in rebuttal testimony take into account the delays due to weather, the contract plans to reduce some of those delays, and the construction cycle. In addition, Peoples Gas notes that while the AG's rebuttal proposal is based on capital expenditures through July 2014, the AG's Initial Brief shows that in August 2014, actual AMRP capital expenditures were $38,465,000, which is $6,349,000 above the budgeted figure for that month, $32,116,000. However, as the Companies emphasize, even though August was more than $6 million above the budget for that month, the AG made no modification to reduce its proposed adjustments. Peoples Gas contends that the August data is consistent with Peoples Gas' rebuttal figures, not the AG's proposal. Peoples Gas further states that the AG's arguments also effectively ignore the contractors' plans to make up in part for the delays earlier in the year, and disregard the Companies witness' testimony regarding opportunities that developed after the revised budget was prepared.

The AG also argues that according to Companies witness Mr. Lazzaro's testimony, the expected AMRP expenditures for the last four months of the year are $25 million to $30 million per month, which are contrary to the revised budget's figures for those months. However, Peoples Gas emphasizes that the AG's argument again ignores the fact that August 2014 expenditures were more than $6 million over the revised budget, ignores the contractors' plans to make up in part for the delays earlier in the year, and disregards Mr. Lazzaro's testimony regarding opportunities that developed after the revised budget was prepared. Further, Peoples Gas notes that the AG complains that when the Companies' witness Mr. Lazzaro testified about the opportunities that developed after the revised budget was proposed, he did not explain them in more depth. In response, Peoples Gas emphasizes that this was cross-examination, and the AG did not ask Mr. Lazzaro to do so. Rather, the AG stopped its cross-examination of Mr. Lazzaro at that exact point.

Peoples Gas contends that the AG's proposal to adjust costs of removal associated with AMRP based on January through July 2014 actual costs lacks merit for the same reasons as the proposal to reduce AMRP costs, with one exception. Peoples Gas explains that here, inconsistently, the AG points to the fact that August 2014 data also was under the revised budget, and Peoples Gas argues that the AG cannot have it both ways. The AG cannot claim that the August removal costs being almost $1 million under the budget supports its proposal, while the August AMRP costs being over $6 million over the budget somehow is irrelevant and does not undercut its proposal.

In addition, Staff's own cross-examination exhibit shows that August 2014 AMRP additions were $27,364,786.36. Staff Group Cross Ex. 1 at Peoples Gas' response to Staff data request ("DR") DLH 34.04. Peoples Gas argues that the evidence supports the Companies' rebuttal figures and negates the AG's proposal and the Staff witness' speculation.

Peoples Gas notes that Staff witness Ms. Hathhorn's rebuttal testimony stated that Staff would support the direct testimony version of the AG's proposal, subject to the AG's direct testimony proposal being updated and corrected. In addition, Peoples Gas offers that Staff provided no testimony that addressed the merits of any version of the AG proposal, apart from Staff's speculation that Peoples Gas' rebuttal's reduced figures did not appear attainable.

Peoples Gas finds that Staff's support of the AG's proposal is based primarily on figures for QIP additions (which includes both AMRP additions and the uncontested revised costs of the Calumet project), less retirements. Peoples Gas adds, however, that Mr. Effron's rebuttal proposals are based on his analysis of capital expenditures (not additions), and do not factor in retirements.

Peoples Gas claims that Staff's discussion, by focusing on additions and not expenditures, fails to take into account the large amount of 2014 AMRP expenditures that already have been incurred but have not yet been recorded as additions.

Peoples Gas states that on October 17, 2014, Staff filed a motion that the Commission take administrative notice of an existing filing relating to September QIP additions and related data and certain future filings relating to QIP additions and related data. The Companies filed a response on October 29, 2014, in which they did not object to Staff's motion but they expressed concerns with how the information might be used by the Commission and regarding its selectivity (providing update information regarding one area of costs but no others, such as paving costs, which are increasing). Staff filed a reply on November 3, 2014, that accepted the Companies' caveats about use of the information and did not discuss the subject of selectivity. On November 5th, the Administrative Law Judges granted Staff's motion, and incorporated certain caveats. The Companies state that the data in the attachment to Staff's motion does not support the AG's proposal.

As well, Peoples Gas argues that Staff's assertion that the Companies are using their concern about the cap in Rider QIP as a reason to include an excessive amount of 2014 AMRP and associated removal costs in rate base is incorrect. Peoples Gas contends that the AG and Staff are using Rider QIP as a failsafe to argue that the Commission should not worry about excessive rate base reductions here because the rider will fix them. Peoples Gas emphasizes that the Companies are not arguing that anything about the rider means that the Commission should approve any rate base figure that the evidence shows to be too high, but that the Companies are arguing that the facts in evidence show that their rebuttal figures are the only reliable figures.

Peoples Gas notes that the AG's witness also has suggested that, if his proposed adjustment to 2014 AMRP and associated removal costs turns out to be incorrect, then the mechanism of Rider QIP will correct for the error. According to Peoples Gas, the Staff witness appeared to accept that reasoning. Peoples Gas argues that this reasoning is a highly problematic over simplification. If the Commission reduces the 2014 AMRP costs and related removal costs as urged by the AG (and Staff), and it turns out that 2014 costs are higher than Mr. Effron speculated they will be, then the amount of QIP investment that Peoples Gas can make and recover under Rider QIP while staying within the annual average revenue cap in 2015 (and in all subsequent years until new base rates are set and in effect) will be reduced. As a result, that could potentially adversely impact future QIP projects, mainly the AMRP, unless Peoples Gas was to file another rate case.

Peoples Gas submits that there is only one reasonable set of figures for 2014 AMRP additions and the associated costs of removal, which are reflected in the Companies' rebuttal testimony. Peoples Gas contends that the reduced 2014 AMRP costs figures (including the removal costs), as reflected in rebuttal testimony, should be adopted.

The foregoing discussion of Peoples Gas' position is subject to the alternative proposal made by the utility in its Brief on Exceptions, in the interests of narrowing the issues. Peoples Gas, in the alternative, proposed to update the 2014 AMRP costs, and the associated costs of removal (and the Calumet system upgrade project costs), based on (1) the actual additions and removals data through November 2014 filed by the Utilities and made part of the record in this case pursuant to a Staff motion granted by the Administrative Law Judges and (2) Peoples Gas' estimates for December 2014 as of its rebuttal testimony.

Staff's Position

Staff recommends that the Commission adopt the AG's revised adjustment to Peoples Gas' 2014 AMRP additions that also qualify as Rider QIP additions, so that rate base is set at a reasonable level, rather than the Company's forecast which appears unattainable. Staff notes that the amount of AMRP additions included in rate base will be adjusted to actual costs through the Rider QIP surcharge. Therefore, Staff finds that the primary impact of the 2014 AMRP Additions adjustment will be its impact on base rate revenues for purposes of the future Rider QIP cap.

Staff maintains that while the Company did reduce its 2014 forecasted additions for AMRP and the Calumet Pipeline Project in rebuttal testimony, the record shows that the Company's forecast is still not reasonable. Peoples Gas has added approximately $51 million in additions through August 2014. Staff asserts that the Company would need to place in service more than double that amount in September through December 2014 in order to attain its forecast of $173 million. The Company would have to invest more than $100 million in just three months to hit its forecast.

Staff adds that Rider QIP contains a revenue cap at Section 9-220.3(g) of the Act, which limits increases billed under Rider QIP to an annual average of 4% of base rate revenue, not exceeding 5.5% in any given year. The Company is concerned that if the appropriate 2014 AMRP additions amount is not included in the approved base rate revenue, the amount of QIP investment that can be recovered under Rider QIP after new rates become effective as a result of this proceeding (2015 and subsequent years) will be impacted. Staff emphasizes that everything from this case which impacts base rate revenues will affect the new Rider QIP revenue cap, not just the level of Rider QIP additions allowed in rate base. Further, the existence of the cap is not adequate justification to allow rates that include an unreasonable amount of rate base. Base rate revenues should determine the cap. The Company's position would flip that and have the cap determine base rate revenues. Staff concludes that this proposal by the Company is neither just nor reasonable.

In its Brief on Exceptions, Staff discussed the updated evidentiary record reflecting the October 2014 AMRP plant additions, and noted that since the ALJs granted administrative notice, the November and December 2014 data may be considered by the Commission in deciding this issue.

AG's Position

The AG explains that in order to determine the forecasted test-year utility plant included in rate base, the Companies began with the actual balances of plant for 2013 and then adjusted those balances for forecasted additions to and retirements from plant for calendar years 2014 and 2015. Peoples Gas included actual and forecasted 2014 QIP additions in its 2015 test-year rate base, and depreciation on those 2014 QIP additions in 2015 test-year expenses. However, Peoples excluded its 2015 QIP net investments, which will be recovered in 2015 through Rider QIP, from any test-year calculations. AG witness Mr. Effron sought to estimate actual PGL AMRP capital expenditure for 2014 as reasonably and accurately as possible. Through his estimation, Mr. Effron found that PGL's forecast of total 2014 AMRP capital expenditure is inflated and must be reduced.

The AG notes that in a discovery response prior to Mr. Effron's rebuttal testimony, Peoples Gas provided figures on actual AMRP expenditure (which includes additions plus construction work in progress, or "CWIP") for January through July of 2014, which made the average monthly expenditure for those seven months approximately $14.3 million, translating to a twelve-month total of $171.559 million. Meanwhile, Peoples is forecasting a total of $237.436 million in 2014 AMRP capital expenditure.

The AG states that Mr. Lazzaro confirmed during cross-examination that for all seven months of January through July, 2014, the actual amount of AMRP expenditure was below the budgeted amount. The AG continues that high spending in August 2014 can be understood because summer is the "peak" season for construction, but summer is now over, and we should not expect that actual spending in the final four months of 2014 will equal budgeted capital expenditure. The AG maintains that in light of the Company's poor track record of actually spending up to its budget on the AMRP program, the Commission should not give weight to the Company's optimistic projections for the remaining months of 2014.

The AG continues that in light of this large discrepancy between actual spending and budgeted spending, Mr. Effron thus proposed reducing the 2014 AMRP expenditures included in PGL's test-year rate base accordingly, from the Company's forecast of $237.436 million to the more reasonable forecast of $171.559 million – a downward adjustment of $65.877 million. He also proposed correspondingly reducing the PGL 2015 test-year depreciation expense by $2.365 million which include Mr. Effron's adjustment to 2014 forecasted cost of removal.

The AG explains that there is no risk to PGL of any possible under-measurement of its 2014 AMRP capital expenditure, because, as Peoples indicated in testimony, if actual 2014 QIP additions are greater than the amount approved in base rates through this proceeding, Peoples Gas will recoup the difference through the first Rider QIP filing after base rates pursuant to this proceeding go into effect in early 2015, so the Company faces no risk of under-recovery.

The AG asserts that doubling down on the Company's overly optimistic projections for the remainder of 2014 shown at AG Cross Exhibit 9, Mr. Lazzaro stated in surrebuttal testimony that it is expected that the expenditures for the rest of the year will be $25.0 to $30.0 million per month without giving any justification for the claim. Asked during cross-examination to reconcile these vastly disparate figures, Mr. Lazzaro indicated that PGL did not learn any new information between the times of the August 12 discovery response and the September 12 surrebuttal testimony that caused the Company to increase the budgeted AMRP spending amounts. On the other hand, he indicated that some projects were included that allowed the Company to do additional work later in the year based on opportunities presented by the City and based on weather. The AG contends that Mr. Lazzaro did not, however, attempt to explain these alleged "opportunities" in any more depth or show how the budgeted amounts as of August 12 could double or more than double in just a month's time. The AG submits that the sudden and drastic change in the Company's forecasted AMRP monthly expenditures lacks credibility and should not serve as a basis for the Commission to approve the Company's forecast. The AG asserts that if the August 12 budget is difficult to believe, the "$25.0 to $30.0 million" forecast in Mr. Lazzaro's surrebuttal testimony is even more outlandish. The AG concludes that the Commission should approve Mr. Effron's downward adjustment to 2014 AMRP capital expenditure to be included in rate base.

Further, the AG states that Mr. Effron proposes modifying the cost of removal related to 2014 QIP property in line with his proposed modification to forecasted 2014 AMRP additions. As of rebuttal testimony, Mr. Effron proposed reducing the PGL forecast of $34.353 million of 2014 AMRP cost of removal to $17.122 million, in line with the actual AMRP cost of removal for the first seven months of 2014. The rate base effect of this adjustment is $10.136 million.

In surrebuttal testimony, AG witness Mr. Lazzaro suggested that, similar to his arguments on 2014 AMRP expenditures, the expenditures related to AMRP cost of removal will also increase to reflect the peak months of construction in 2014 and thus no adjustment is appropriate. The AG argues, however, for the same reasons as estimated AMRP capital expenditures lack credibility, his statement on the related cost of removal cannot be taken seriously.

Mr. Lazzaro confirmed during cross-examination that for all seven of the months of January through July of 2014, the actual cost of removal shown on PGL Exhibit 38.1 was below the actual cost of removal shown on AG Cross Exhibit 9. He also agreed that the actual cost of removal for August 2014 was approximately $1 million below the budgeted cost of $3.2 million. The AG argues that in light of the Company's consistent discrepancies between actual and budgeted cost of removal for AMRP, the Commission should approve Mr. Effron's proposed downward adjustment to 2014 AMRP cost of removal.

In summary, the AG states that the total rate base effect of Mr. Effron's proposed adjustment to PGL's forecasted 2014 AMRP additions is to reduce test-year rate base by $72.843 million. Additionally, Mr. Effron's proposal reduces PGL's 2015 test-year depreciation expense by $2.365 million. The AG offers that in light of the Company's consistent failure to spend up to budgeted amounts, the Commission should not simply take the Company's promises of late-year 2014 spending at face value.

<u>Commission Analysis and Conclusion</u>

The Commission approves Peoples Gas' proposal to update the 2014 AMRP costs and the associated costs of removal, and the Calumet system upgrade project costs, as proposed in the Utilities' Brief on Exceptions. The "middle ground" proposal was accepted by both the AG and Staff in their Reply Briefs on Exceptions. The proposal is based on a reasonable methodology of annualizing actual data on net plant additions for January through November of 2014 that was entered into the record as well as Peoples Gas' December 2014 costs as previously estimated in its rebuttal.

The Commission has acknowledged the importance of the Peoples Gas AMRP project, has prioritized the acceleration of the program, and notes the varied benefits for customers that will arise out of this program. Pursuant to 220 ILCS 5/9-220.3, Peoples

Gas is entitled to allowed rider recovery of qualifying infrastructure plant, including accelerated main replacement costs, but the 2014 costs at issue will become part of rate base here, and no longer recovered under the rider.

Peoples Gas will recover its actual prudent costs of AMRP additions by use of an adjustment through Rider QIP. However, although the revenue cap restriction on Rider QIP that will be set in this case pursuant to Section 9-220.3(g) of the PUA does not prohibit Peoples Gas from filing for rate recovery under a traditional rate case should the cap restriction begin to influence Peoples Gas' AMRP progress, this Order in its ruling on the subject of rate case expense amortization, Section V.C.4 of this Order, assumes that the Commission will approve the proposed WEC-Integrys transaction in the pending reorganization approval Docket and, further, will approve a proposed commitment not to file for rates that will be effective for before two years from the closure of the transaction. If the reorganization is approved, therefore, Peoples Gas might be precluded from filing for rate recovery to alleviate the restrictions placed on Peoples Gas' AMRP progress by the revenue cap. Thus, it is essential to approve the most reasonable figures for these costs, which are found in the Peoples Gas updates.

2. Cash Working Capital

a. Other Post Employment Benefits (OPEB) lead

<u>Companies' Position</u>

The Companies explain that CWC essentially is the amount of funds (positive or negative) required to finance the day to day operations of a utility, and that the CWC requirement is included in each of the Companies' rate bases for ratemaking purposes. To determine the CWC requirement, a lead-lag study analyzes the differences between the revenue and collection lags and the expense leads of a utility in order to measure and quantify the impact and timing of the utility's cash flow. The Companies further explain that three broad categories of leads and lags are considered in such a study: (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 payment for goods and services received by the utility. The Companies state that, in order to determine the leads and lags in the CWC analysis, the Companies utilized data from the Companies' Accounts Payable, Customer Service, Payroll, General Ledger, and Tax Systems, as well as records from the Companies' bank accounts. As discussed in Section IV.B.3 above, the Companies' CWC figures are not contested, apart from the figures for the OPEB lead and any derivative impacts of contested operating expense adjustments that affect the applicable inputs to the CWC calculations.

The Companies state that, based on an analysis of payments to a trust for OPEB during calendar year 2012 (the last full year for which data was available at the time the CWC lead-lag studies were prepared), the Companies calculated lead expenses of negative 66.64 days for North Shore and negative 99.09 days for Peoples Gas.

The Companies note that the use of a lead-lag study to calculate the Companies' CWC requirement is not contested. However, Staff contests the Companies' OPEB expense lead, arguing that the Companies' cash payments for OPEB during calendar year 2012 were not made in accordance with "normal practice," and that a payment date of December 18, 2012, is more reasonable than the Companies' January 9, 2012, payment date. Based on this adjustment, Staff argues that the OPEB CWC factor should be adjusted to a positive lead of 170.00 days for North Shore and a positive lead of 169.91 for Peoples Gas.

The Companies argue that Staff's proposal to reject the actual cash flow data from 2012 relating to the OPEB leads and to substitute hypothetical later payments is flawed, inconsistent with the Staff position adopted by the Commission in prior rate cases, and one-sided. The Companies assert that their OPEB leads are based upon the most recent calendar year data that were available at the time the lead-lag studies were conducted, and that in accordance with customary practice, the Companies considered the timing of all of the payments made during the year and dollar weighted them, resulting in proposed negative lead values of 66.64 for North Shore and 99.09 for Peoples Gas.

The Companies argue that Staff's adjustment is based solely on its subjective opinion that a payment made at the end of the year is more appropriate than a payment made at the Company's discretion, when funds were available. The Companies note that Staff admits that the OPEB trust payments did not have specific due dates. According to the Companies, Staff bases its adjustment on a limited historical view of the Companies' OPEB payments, arguing that, based on payments made in 2013 and pending payments in 2014, it appears the normal practice is to pay in December. The Companies contend that in two out of the last three full calendar years, the Companies made OPEB payments very early in the year. The Companies argue that Staff's assertion that the Companies' OPEB trust payments were inconsistent with "normal practice" is unsupported and based on a subjective and selective evaluation of the Companies' historical practices, and that Staff's adjustment should be rejected.

The Companies further note that Staff's position is inconsistent with its position taken in Docket Nos. 12-0511/12-0512 (Consol.), during which Staff argued that the OPEB lead should be set at the intercompany billing lead. Docket Nos. 12-0511/12-0512 (Consol.), Order at 80; NS-PGL Ex. 22.0 REV at 6-7. In the instant proceeding, the Companies note, Staff does not propose to continue the use of the intercompany billing lead, but instead bases the adjustment to the OPEB Expense Lead on the cash flows provided by the Companies during calendar year 2012 as adjusted by Ms. Hathhorn. This adjustment results in lead changes from negative to positive, resulting in a decreased CWC. The Companies argue that Staff has offered no valid justification for this inconsistency.

Further, the Companies argue that Staff bases its adjustment on an inapposite and irrelevant Commission Order in an unrelated docket. The Companies explain that Ms. Hathhorn cited to the Commission's final Order in an Ameren Illinois Company ("AIC") docket, Docket No. 13-0192, arguing that the Commission previously ruled that CWC factors should be calculated based on payment due dates rather than internal policies. According to the Companies, this argument is unsupported and unrelated to the issue of OPEB trust payments made in the absence of any specific due dates. In ICC Docket No. 13-0192, the Commission examined challenges to AIC's payment of pass-through taxes based on billing dates rather than collection dates, in contravention of statutory due dates or due dates prescribed by municipal ordinances. *Ameren Illinois Company d/b/a Ameren Illinois*, Docket No. 13-0192, Order at 15-20 (Dec. 18, 2013). In adopting the proposals propounded by Staff and various intervenors, the Commission noted that "AIC's practice of remitting pass-through taxes earlier than required increases rate base by increasing CWC." *Id.* at 19. The Companies emphasize that, in clear contrast to the AIC docket, the OPEB trust payments at issue in the instant proceeding have no required due date, either through statute, municipal ordinance, or prior Commission decision, and argue that Staff's reliance on Docket No. 13-0192 as support for its adjustment is misplaced and should be rejected.

The Companies further point out that the lead-lag studies are based on data that consists of hundreds of thousands of cash transactions, and that Staff has shown no sound reason to modify only the OPEB lead payment dates, particularly when that would result in significantly reducing the cash working capital available to meet day-to-day operational needs.

The Companies contend that Staff's proposal also is incorrect because the OPEB liability already is a rate base deduction, meaning the lead should be zero days, and making Staff's proposal a double-counted reduction to rate base, although the Companies recognize that the Commission did not adopt their view that the lead should be zero days in Docket Nos. 12-0511/12-0512 (Consol.).

Finally, the Companies argue that Staff's proposal is one-sided. Customers have the benefit of the actual payment date in the form of reduced OPEB expenses that resulted from the actual payment date (the "early" payment according to Staff) being included in the calculation of operating expenses in the Companies' revenue requirements. OPEB expenses, all else being equal, are reduced by contributions to the OPEB trust and the earnings on the assets resulting from those contributions. According to the Companies, the Staff position would deny the Companies the time value of the actual payment date, while giving customers the benefit of the actual payment date, which is unfair and unreasonable.

The Companies note that, in its Initial Brief, CCI expressed support for Staff's position based wholly on Staff arguments. The Companies conclude that Staff's proposal, as supported by CCI, should be rejected and that the Companies' CWC figures should be approved.

<u>Staff's Position</u>

Staff and the Companies agree on the methodology to update CWC for the final revenue requirements ordered by the Commission in the instant cases, and for all leads and lags except for the expense lead for pension and OPEB. Appendices A and B to Staff's Initial Brief, use an OPEB payment date in December, rather than January as used by the Companies, because the OPEB December payment date appears more reasonable in light of past payments by the Companies. This results in an OPEB positive lead of 170.00 days in the CWC calculation for North Shore, rather than a negative expense lead of (66.64) days, and a positive lead of 169.91 days in the CWC calculation for Peoples Gas, rather than a negative expense lead of (99.06) days, because it is not reasonable to base the 2015 future test year on the early payment date that occurred in 2012.

The Companies opine that because the OPEB payments do not have a statutory due date, a payment cannot be deemed early or late. Staff disagrees and points to the historical OPEB payment activity. Staff's position is that basing the expense lead for OPEB in the CWC calculation based upon the Companies' past payment practice for OPEB for one of the last six years is not prudent or reasonable. Staff asserts that the early OPEB trust fund payments of $7.5 million for North Shore and $67.5 million for Peoples Gas, combined with the payment made so early in the calendar year, actually creates a negative lead or a revenue lag. Staff maintains that the Companies' position creates a higher CWC and rate base than is necessary when using their customary payment practice.

Staff notes that the Commission has previously ruled that CWC and rate base should not be increased when Companies pay expenses earlier than necessary. For instance, in Docket No. 13-0192, AIC proposed that the expense leads for its pass-through taxes be set based on the amount of time AIC holds the funds before remittance. However, in Docket 13-0192, Staff, the AG and CUB proposed that the calculation be instead based on when the taxes are due, consistent with prior Commission Orders in Docket Nos. 12-0001, 12-0293, 11-0721, and 12-0321. Staff submits that the Commission agreed with Staff, the AG and CUB:

> The Commission agrees with Staff and AG/CUB that their proposal is consistent with recent Commission Orders and will protect ratepayers from incrementally higher rates attributable to the utility's practice of remitting taxes earlier than they are due. As Staff points out, AIC's practice of remitting pass-through taxes earlier than required increases rate base by increasing CWC.

Docket No. 13-0192, Order at 19.

Staff reasons that the AIC Order addressed pass-through taxes having a statutory due date while in this proceeding, the OPEB payments do not have a statutory due date. But, like AIC, the Companies are proposing an earlier payment date than required that unnecessarily and unreasonably increases rate base. Staff continues that because the OPEB trust fund payments do not have a set due date, the CWC factor should be based on the Companies' normal payment policy date of December, consistent with the Commission's position that early payments should not result in increased rate base to rate payers.

<u>CCI's Position</u>

CCI supports Staff witness Ms. Hathhorn's proposal to use a December payment date for OPEB rather than a January payment date (as proposed by the Companies) in calculating the related CWC requirement. As Ms. Hathhorn noted, in four of the last six years, the Companies made their largest OPEB payment in December. CCI states that in only one of the past six years was the Companies' largest OPEB payment in January.

CCI argues that assuming an anomalous January payment date instead of a December payment date serves to increase the Companies' rate base. CCI stresses that the Commission must carefully examine the record evidence in considering when the Companies are most likely to actually make their OPEB payment in the 2015 test year. According to CCI, the manifest weight of the evidence points to a December payment date as the most reasonable for ratemaking purposes.

CCI concludes that the Commission should approve Ms. Hathhorn's proposal to use an OPEB positive lead of 170.00 days in the CWC calculation for NS and a positive lead of 169.91 days in the CWC calculation for PGL.

Commission Analysis and Conclusion

The Commission agrees with Staff and CCI and approves an OPEB positive lead of 170.00 days in the CWC calculation for North Shore and a positive lead of 169.91 days in the CWC calculation for Peoples Gas. Considering the historical OPEB payment activity and the lack of a required payment date, the Commission finds that it is not reasonable to base the 2015 future test year on the early payment date that occurred in 2012. It is the Commission's position that CWC and rate base should not be increased when utilities pay expenses earlier than necessary.

3. Retirement Benefits, Net

Companies' Position

The Utilities recognize that the Commission, in the Utilities' 2007, 2009, 2011, and 2012 rate cases, found that: (1) the Peoples Gas pension asset (and the North Shore pension liability or asset, as applicable) should not be included in the calculation of rate base; and (2) the Utilities' OPEB liabilities nonetheless should be included in the calculation; and (3) that the Docket Nos. 09-0166/09-0167 (Consol.) Order was affirmed on appeal on this subject. *North Shore Gas Co./The Peoples Gas Light and Coke Co.*, Docket Nos. 09-0166/09-0167 (Consol.) (Jan. 21, 2010). While the Utilities agree with the Commission's past findings that, if a pension asset is excluded, then a pension liability also should be excluded, the Utilities respectfully request that the Commission reconsider whether to include Peoples Gas' pension asset in the instant proceeding, and, alternatively, whether to include specific pension liabilities in rate base or to exclude amounts related to pensions. Also, the Commission should reject Staff's proposal to exclude the Peoples Gas pension asset from rate base while including the North Shore pension liability, which is contrary to the Orders in Docket Nos. 07-0241/07-0242 (Consol.) and Docket Nos. 09-0166/09-0167 (Consol.). *North Shore Gas Co./The Peoples Gas Light and Coke Co.*, Docket Nos. 07-0241/07-0242 (Consol.) (Feb. 5, 2008)

Using average rate base, as updated in rebuttal testimony, North Shore's pension liability is $(8,000), and Peoples Gas' pension asset is $17,350,000. NS-PGL Ex. 22.9N, line 11, col. (G); NS-PGL Ex. 22.9P, line 11, col. (G).

The Utilities explain that the Commission's past decisions to exclude the Peoples Gas pension asset (and, when applicable, North Shore's) from rate base were based on findings that the asset is, or at least has not been shown not to be, the product of customer-supplied funds. *E.g.,* Docket Nos. 07-0241/07-0242, Order at 36. The Utilities note that Staff advances that same position in the instant cases, while the AG simply proposes to apply the prior Commission decisions.

The Utilities argue that the Commission should reconsider approving inclusion of the pension asset(s) in rate base for several reasons. First, the premise that customers, by paying utility bills, should be treated as if they had paid for the utility's assets, is incorrect as a matter of law. Customers pay for service, not for the property used to render it. *Board of Pub. Utility Commissioners, et al. v. New York Tel. Co.*, 271 U.S. 23 (1926). Second, the pension asset is part of the utility's balance sheet and, with respect to defined benefit plans, the utility owns the assets via the trust that holds the assets, with the employees being the beneficiaries of the trust.

Third, the rates on which customers' bills are based reflect the accrual of pension expense. The Utilities submit that although Staff claims that customers paid for the pension asset (and the AG does so implicitly by citing past Orders to that effect), Staff does not explain how customers supposedly pay for the pension asset, and, specifically, does not refute the fact that the bills customers pay are based on the accrual of pension expense. The Utilities assert that a pension asset exists when cumulative funding exceeds the cumulative amount of recognized pension expense. The Utilities contend that customers did not pay for the excess by which cumulative pension funding exceeds cumulative recognized pension expense, which means that they did not pay for the pension asset. In addition, the Utilities state that the rates upon which customers' bills are based reflect the accrual of pension expense. The Utilities note that Staff simply argues that pension assets are created with funds supplied by customers, and that the Utilities have not provided evidence to distinguish this case from prior Commission rulings, yet fails to provide any new evidence to support its claims.

Fourth, the Utilities maintain that normal operating revenues of a utility include amounts collected through rates to repay the utility's cost of capital, and the portion of amounts collected from customers that end up as net income is retained earnings, and thus is part of shareholders' equity, to the extent it is not paid out in dividends. The Utilities note that Staff admitted that the pension asset is funded by normal operating revenues. The Utilities emphasize that the evidence demonstrates that funds from normal operations include repayment of the utility's cost of capital, so the utility's use of that repayment for pension funding does not mean that the funding is not capital of the utility. In addition, the Utilities contend that Staff's reasoning is inconsistent. When the subject at hand is whether incentive compensation costs should be recovered, and the metric is net income, Staff contends, and the Commission has agreed, that the metric is "shareholder-oriented". Yet, here, where it has been shown that the prepayment of pension expense is a reduction to net income and retained earnings, Staff contends that the funds in question are customer-supplied.

Fifth, the Utilities argue that cumulative pension contributions have exceeded cumulative recognized Generally Accepted Accounting Principles ("GAAP") pension expense. The Utilities note that Staff has not disputed this point.

The Utilities find that in the instant proceeding, Staff has only offered a limited response to the Utilities' point regarding the normal operating revenues of a utility, asserting that the facts between the instant proceeding and the prior Commission Orders are unchanged and that the Utilities' arguments are based solely on theoretical contributions. However, the Utilities argue, Staff continues to fail to provide a sound reason those particular points are incorrect or do not support the inclusion of the pension assets in rate base. Thus, the Utilities contend that the Commission has sufficient grounds for reconsidering this issue and note that the decision should be based on the evidence in the record of the instant Dockets. 220 ILCS 5/10-103; 220 ILCS 5/10-201(e)(iv)(A).

The Utilities note that the AG's Initial Brief did not respond to or dispute any of the Utilities' points in detail; instead, the AG asserted that the adjustments made by its witness were in accordance with the Commission's previous findings in the past relevant dockets. In addition, the Utilities note that although CCI did not address this issue in testimony, CCI argues that the Commission should adopt the proposal to properly account for pension assets, which are ratepayer funded. CCI simply refers to the past Commission decisions on this topic, and adopts the propositions of Staff and the AG.

Finally, while Staff espouses adherence to the prior Orders as to exclusion of Peoples Gas' pension asset from rate base, Staff's rebuttal inconsistently argues for subtracting the North Shore pension liability, even though that same Staff proposal was rejected in the prior Orders. More specifically, Staff made the same proposal in the Utilities' 2009 rate cases, and the Commission's Order in Docket Nos. 09-0166/09-0167 (Consol.), Order at 36-37 rejected it, just as had occurred in the Utilities' 2007 rate cases, and Staff has not provided any change in circumstances or any basis for a different outcome here. Even the AG's witness opposes the inclusion of the North Shore pension liability in the rate base calculation if the Peoples Gas pension asset is excluded.

Accordingly, the Utilities assert that the Commission (1) should approve the inclusion of Peoples Gas' pension asset and North Shore's pension liability in rate base, or, alternatively (2) should exclude the Peoples Gas pension asset and the North Shore pension liability, the latter being as ordered in Peoples Gas 2007 and Peoples Gas 2009 when one utility had a pension asset and the other had a liability.

Finally, if the Peoples Gas pension asset is not included in rate base, then the Utilities respectfully contend that consistency of reasoning would require removal of the OPEB liabilities from rate base, although the Utilities acknowledge that the Commission rejected that contention in past rate cases.

<u>Staff's Position</u>

Staff submits that disallowances from rate base for the Companies' pension assets and related ADIT are required because the Companies have not demonstrated that they were created with anything other than ratepayer funds. The Commission has repeatedly held that shareholders are not entitled to a return on ratepayer-supplied funds. Staff states that the Companies' criticisms of prior orders of the Commission and Appellate Court do not diminish those rulings.

Staff asserts that Peoples Gas acknowledges that the Commission ruled that its pension asset should not be included in rate base in its last four general rate cases, but continues to argue that inclusion is warranted. Staff notes that North Shore has also not had a pension asset in the last four rate cases. However, Peoples Gas states that its additional grounds for inclusion in rate base in its Docket Nos. 12-0511/12-0512 (Consol.) were not explicitly addressed by the Commission's final Order. Staff responds that Peoples Gas mischaracterizes the Commission's final Order in its 2012 rate case which specifically sets forth all of Peoples Gas' claims for its position (Docket Nos. 12-0511/12-0512 (Consol.), Order at 80-82) and the Commission's conclusion shows that it rejected those claims (*Id.* at 90). Staff adds that the Commission is not required to make a particular finding as to each evidentiary fact or claim made by a party. *United Cities Gas Co. v. Illinois Commerce Comm'n*, 47 Ill.2d 498, 501 (1970).

Peoples Gas criticizes Staff's reliance on the Appellate Court decision arising out of Docket Nos. 09-0166/09-0167 Cons. ("2009 Court Opinion") because the Commission and Court did not specifically refute all the Company's points made in Docket Nos. 11-0280/11-0281 (Consol.) and the 2012 rate cases. Staff offers that while there are still appeals outstanding on the 2011 and 2012 rate cases, the 2009 Court Opinion which rejected the Company's pension asset arguments is still good law.

Staff contends that the evidence presented by the Companies in this case simply does not distinguish this case from prior Commission rulings on the same subject. The Companies provided no evidence that the contributions were made from any source other than normal operating revenues (*i.e.* direct unequivocal contributions from shareholders creating a "pension asset"). The Companies state only that contributions to the pension plan "would be first funded from operating cash flows. If operating cash flows are insufficient, the cash requirements are funded with short-term debt; short-term debt would be replaced as needed by long-term debt and equity to maintain our capital structure. Thus contributions are ultimately funded by capital." Attach. B to Staff Ex. 1.0

Staff submits that prior orders reject any inclusion of a pension asset in rate base for anything other than a specific contribution from shareholders. In Docket Nos. 09-0166/09-0167 (Consol.), the Commission denied inclusion of Peoples Gas' pension asset in rate base because there was no evidence in the record it was created with shareholder funds:

> The Companies have given us no reason to overturn our decision from their last rate case. Although the Companies state that the pension asset was created with shareholder funds, no evidentiary support was provided. The Commission finds no support in the record to allow for the inclusion of Peoples Gas' pension asset in rate base which in turn would allow shareholders to earn a return on ratepayer supplied funds.

Docket Nos. 09-0166/09-0167 (Consol.), Order at 36. The Illinois Appellate Court upheld this order, stating:

> The central issue before us remains whether the Commission's decision to exclude the pension asset, which it found consisted of consumer-supplied funds, from Peoples Gas' rate base was against the manifest weight of the evidence. Both the Staff's and the People's expert witness

> testified the pension asset constituted customer-supplied revenues and, therefore, should be deducted from the rate base calculation.
>
> …
>
> Based on the record before us, we find the Commission's decision with regard to the pension asset deduction is not clearly against the manifest weight of the evidence. Accordingly, we see no reason to disturb the Commission's findings.

Peoples v. Illinois Commerce Commission, Nos. 1-10-0654, 1-10-0655, 1-10-0936, 1-10-179, and 1-10-1846 and 1-10-1852, Consolidated, Appellate Court (First District-Fifth Division) September 30, 2011, at 42-43, par. 69-71.

Staff adds that the Commission denied inclusion of the pension asset in the subsequent two North Shore/Peoples Gas rate cases. *See* generally, *North Shore Gas Co./The Peoples Gas Light and Coke Co.*, Docket Nos. 11-0280/11-0281 (Consol.), Order at 33 (January 10, 2012); Docket Nos. 12-0511/12-0512 (Consol.), Order at 90.

Staff mentions that in three separate gas rate cases, Docket No. 08-0363, Docket No. 04-0779, and Docket No. 95-0219, Northern Illinois Gas Company d/b/a Nicor Gas Company sought to increase utility rate base for the amount of a prepaid pension asset. In all three cases, the Commission found that the pension asset was created by ratepayer-supplied funds, not by shareholder-supplied funds. The Commission concluded that ratepayers should not be denied the benefits associated with the previous overpayment for pension expense which ratepayers funded. Accordingly, the Commission concluded that the pension asset should be eliminated from rate base.

Likewise, in Docket No. 11-0767, the Commission ruled that Illinois American Water Company's proposal to include a pension asset in rate base was not substantively different than those the Commission had considered, and rejected, in past rate case decisions.

Staff states that the only time the Commission has allowed a return on pension plan payments was the identification of a specific contribution from shareholders, not a theoretical contribution as the Company argues here. It is undisputed that the Company has an expected pension contribution of $0 for the test year. Additionally, the return on the specific pension payment previously approved by the Commission was a debt return, not the cost of capital. *Commonwealth Edison Company*, Docket No. 05-0597, Order on Rehearing at 28-29 (Dec. 20, 2006). Staff asserts as well that while the Electric Infrastructure Investment and Modernization Act ("EIMA") does allow an investment return on a pension asset recorded in FERC Account 186 to be included in rates, that is specifically authorized in EIMA and does not apply to Peoples Gas.

Staff notes that the Companies argue that the more cash Peoples Gas or North Shore contributes into the trust, the lower the pension costs that Peoples Gas or North Shore has to record and ultimately recover from customers through rates. Staff responds that this argument fails to acknowledge that the Companies will receive the full amount of actuarially determined pension expense in the revenue requirement. In other words, Staff's proposed adjustments do not disallow the costs for the annual pension expense. However, Peoples Gas states that it made no contributions into the qualified pension plan during 2013 and 2014 and the Companies updated actuarial reports reflect zero employer contributions for the year 2015 for both Companies. Staff explains that its adjustments, which do not affect the amount to be recovered by the Companies in operating expenses, would have no effect on future pension contributions.

The Companies state that their argument for pension asset inclusion in rate base would be consistent with the current exclusion of their OPEB liabilities from rate base ("symmetry argument"). Staff claims that the Companies' position to include pension assets in rate base has no bearing on the proper exclusion of an OPEB liability from rate base.

Staff details that OPEB liabilities represent other post-employment benefits that had not been paid out to the OPEB trust by the end of the year and for which the utility has already received recovery from rates. Rate base is properly reduced by these OPEB liabilities to recognize that such costs are already recovered from ratepayers by their inclusion as an operating expense. Staff states that it would not be reasonable to allow shareholders a return on this cost-free source of capital to the Companies. Staff argues that the Companies' symmetry argument does not take this into account and that the Commission has also rejected this argument in the past.

Staff explains that in Docket Nos. 07-0241/07-0242 (Consol.) both Peoples Gas and North Shore excluded their OPEB liabilities from rate base*, i.e.,* neither utility reduced rate base for the OPEB liabilities. Peoples Gas also had a pension asset, which the Company did not include in rate base. Peoples Gas argued for symmetrical treatment; that is, excluding both its pension asset and OPEB liability from rate base. The Commission instead found that the pension asset should be excluded from rate base and that the OPEB liabilities should be reflected as a reduction to rate base:

> The Commission agrees with the positions asserted by GCI and Staff. Their arguments are persuasive and fully supported by the evidence. Further, they have each established that the treatment we are being urged to assign to this item today, is the same the treatment that we adopted in a number of previous decisions. On all these grounds, the Commission accepts that a rate base deduction of $7,094,000 ($4,074,000 net of related deferred taxes) is required for the North Shore accrued OPEB liability and a rate base deduction of $55,653,000 ($31,570,000 net of related deferred taxes) is required for the Peoples Gas accrued OPEB liability in the determination of the Companies' rate bases. *See* GCI Ex. 2.0 at 13.
>
> Further, we note that the underlying rationale for these adjustments is that such funds are supplied by ratepayers and not by shareholders such that shareholders are not entitled to earn a return on these funds. Accordingly, the undisputed

> record showing that Peoples Gas and North Shore contributed $15,278,614 and $1,862,247, respectively, to the pension plans during the test year, does not change the treatment of the OPEB liability. Nor are we convinced that such contributions should impact shareholders, given that these funds were provided by ratepayers through the collection of utility revenues. We observe no discussion of or opposition to this particular recalculation that the Companies propose on basis of their contribution, however, it appears to the Commission that recognizing these contributions is inconsistent with, the theoretical basis that we are applying here, *i.e.*, these contributions are ratepayer-funded.
>
> The Commission finds that the Companies' OPEB liabilities will be deducted, and, for the reasons provided by Staff, Peoples Gas' contributions of $15,278,614 and North Shore's contributions of $1,862,247 to the pension plan should not be incorporated into the calculation of the rate bases.

Docket Nos. 07-0241/07-0242 (Consol.), Order at 36. Staff states that the Commission ruled in the same manner in the last two North Shore/Peoples Gas cases, Docket Nos. 11-0280/11-0281 (Consol.) and Docket Nos. 12-0511/12-0512 (Consol.):

> The Commission agrees with both Staff and GCI concerning the adjustments to rate base made to account for net retirement benefits. Staff witness Ebrey agreed with GCI witness Effron's approach which removed the Companies' respective net pension assets from rate base, but kept the OPEB liabilities in rate base. Staff and GCI's adjustments are supported by the evidence and remain consistent with the Commission's conclusions about the pension asset in the 2007 and 2009 PGL rate cases. Those decisions both concluded that the accrued OPEB liability should be reflected in rate base but that the pension balances should not be recognized in the determination of rate base.

Docket Nos. 11-0280/11-0281 (Consol.), Order at 33.

> The Commission finds that the Companies' pension assets should not be included in rate base for the reasons stated in its past Orders. The Commission concludes, however, that the OPEB liabilities should be included in rate base, to be consistent with the prior rulings on the pension assets.

Docket Nos. 12-0511/12-0512 (Consol.), Order at 90.

In surrebuttal testimony, Peoples Gas states that if its pension asset is not included in rate base, then North Shore's pension liability should not be included. Staff argues that similar to OPEB liabilities, the Companies' position to include pension assets in rate base has no bearing on the proper exclusion of a pension liability from rate base. Pension liabilities represent pension costs that have not been paid out to the pension trust by the end of the year but for which the utility has already received recovery through rates. Staff submits that rate base is properly reduced by these pension liabilities to recognize that such costs are already recovered from ratepayers by their inclusion as an operating expense. Staff surmises that it would not be reasonable to allow shareholders a return on this cost-free source of capital to the Companies.

The Companies state that the pension assets are included in their balance sheets and that they own the assets via the trusts that hold the assets. Staff argues that it is not relevant who owns the assets of the pension trust fund because ownership is not determinative of ratemaking treatment. For example, contributed plant may be owned by a utility, but a utility does not get a return on contributed plant from a customer. Staff notes that the determining question is whether the pension assets were created with funds from shareholders or ratepayers. Further, Staff states that no evidence of outside discreet shareholder funding of the pension contributions has been presented by the Companies.

Staff reiterates that a large number of Commission orders have concluded that financing a pension asset with internally generated funds does not permit a utility a rate base return on that asset. Staff argues that the Company is seeking to collect monies from ratepayers and then charge those ratepayers with a return on investment of those monies. What is relevant is that under Illinois law for ratemaking purposes a public utility may not receive a return on investment from ratepayers for ratepayer-supplied funds. *City of Alton v. Illinois Commerce Comm'n,* 19 Ill. 2d 76, 85-6, 91 (1960); *DuPage Utility Co. v. Illinois Commerce Comm'n*, 47 Ill. 2d 550, 554, 558 (1971); *Central Illinois Light Co. v. Illinois Commerce Comm'n*, 252 Ill. App. 3d 577, 583 (3rd Dist., 1993); *see also, Business and Professional People for the Public Interest v. Illinois Commerce Comm'n ("BPI II"),* 146 Ill. 2d 175, 258 (1991). Staff reasons that the Commission has consistently rejected the attempts of other Companies to receive a return on ratepayer-supplied funds and should do so again here. *See, Citizens Utility Board v. Illinois Commerce Comm'n,* 166 Ill. 2d 111, 132 (1995) (Commission is unauthorized to depart drastically from practices established in earlier orders); *Mississippi River Fuel Corp. v. Illinois Commerce Comm'n,* 1 Ill. 2d 509, 514 (1953) (long-term consistent actions by the Commission are entitled to great weight and may be equal in force to a judicial construction).

Staff recommends a disallowance of the Companies' pension asset and related ADIT from rate base.

<u>AG's Position</u>

The AG explains that the "Retirement Benefits, Net" rate base entry, as shown on the Companies' Schedule B-1, consist of two components. The first is the prepaid pension asset. The pension asset is mainly the effect of contributions to the pension fund being in excess of the periodic pension cost, or pension income, accrued pursuant to Statement of Financial Accounting Standards 87.

The second component is primarily the accrued liability for future post-retirement OPEB, mainly health care costs. Pursuant to Statement of Financial Accounting Standards 106, the Companies must accrue for the payment of future post-retirement benefits other than pensions. To the extent that the accruals are greater than the actual cash disbursements, accrued liabilities will be reflected on the Companies balance sheets. The AG states that PGL and NS offset the accrued liability for OPEB against prepaid pensions in the calculation of the "Retirement Benefits, Net" that they include in their rate bases.

The AG maintains that in the Companies' recent rate cases, how to treat these benefits has been an issue. In Docket Nos. 07-0241 and 07-0242, the Companies did not take account of the accrued pension and OPEB balances in the determination of rate base. In response to testimony by Staff and intervenors proposing to deduct the accrued OPEB liabilities from rate base, the Companies responded that if the accrued OPEB liabilities are deducted from rate base, then the prepaid or accrued pension balances should also be recognized.

In Docket Nos. 09-0166, 09-0167, 11-0280, 11-0281, 12-0511, and 12-0512, the Companies offset the accrued liability for OPEB against prepaid pensions in the calculation of the "Retirement Benefits, Net" included in their rate bases. The AG argues that this was, in substance, the same treatment that the Companies are presenting in the current cases. The AG states that in all of these cases, the Commission found that the accrued OPEB liability should be deducted from rate base but that the pension balances should not be recognized in the determination of rate base.

Consistent with the Commission's findings in all recent cases, AG witness Effron eliminated the pension balances from rate base, but treated the accrued liability for post-retirement benefits other than pensions as rate base deductions. He also eliminated the accumulated deferred income taxes related to the prepaid or accrued pensions. The net effect of this adjustment, updated in Mr. Effron's Rebuttal testimony to reflect updates addressed in the Companies' Rebuttal testimony, are based on the average 2015 balances. The AG states that the effect of these adjustments is to reduce PGL "Retirement Benefits, Net" by $17,350,000 and related accumulated deferred income taxes by $6,881,000, resulting in a net reduction to the PGL rate base of $10,469,000. With regard to NS, the effect of Mr. Effron's proposed adjustment is to reduce the "Retirement Benefits, Net" by $8,000 and to reduce the related accumulated deferred income taxes by $5,000, which results in a net reduction to the NS rate base of $3,000. The AG submits that these adjustments should be adopted by the Commission.

CCI's Position

CCI recommends that the Commission adopt the adjustment proposed by both Staff witness Hathhorn and AG witness Effron to properly account for pension assets, which are ratepayer-funded. Mr. Effron's "Retirement Benefits, Net" was identical to Ms. Hathhorn's "Pension Asset Adjustments," and both are in line with the Commission's prior holdings. *See e.g.* Docket Nos. 12-0511/12-0512 (Consol.), Order at 90, Docket Nos. 11-0280/11-0281 (Consol.) Order at 33, Docket Nos. 09-0166/09-0167 (Consol.) Order at 36. CCI reasons that consistent with the Commission's previous orders, in the absence of evidence dictating a different result, the Commission should exclude the Companies' pension assets from rate base.

Commission Analysis and Conclusion

Consistent with past Commission decisions, the Commission maintains that accrued OPEB liability should be deducted from rate base but that pension balances should not be recognized in the determination of rate base. The Commission agrees with Staff and the AG and finds that Peoples Gas' pension asset should be excluded from rate base for the reasons stated in its past Orders. Further, the Commission agrees with North Shore and the AG and finds that North Shore's pension liability should also be excluded from rate base as it was in the 2007 and 2009 rate cases.

V. OPERATING EXPENSES

A. Overview/Summary/Totals

North Shore states that its final properly calculated base rate operating expenses (per its rebuttal testimony) are $74,635,000, including income taxes and reflecting the Staff and intervenor adjustments that it adopted or accepted in whole or in part in order to narrow the issues and certain updates. Peoples Gas states that its final properly calculated base rate operating expenses (per its rebuttal testimony as slightly revised in surrebuttal) are $570,562,000, including income taxes and reflecting the Staff and intervenor adjustments that it adopted or accepted in whole or in part in order to narrow the issues and certain updates.

Staff recommends total operating expenses before income taxes of $67,000,000 for North Shore and $506,894,000 for Peoples Gas.

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

1. Other Revenues

In rebuttal and surrebuttal testimony, the Companies updated the proposed other revenues figures. These figures are not contested. Therefore, the Commission approves the Companies' updated figures for these revenue amounts, subject to any derivative impacts, if any.

2. Resolved Items

a. Incentive Compensation

The Companies have three different incentive compensation plans: (i) an Executive Incentive Compensation Plan; (ii) an Omnibus Incentive Compensation Plan, consisting of various stock plans; and (iii) a Non-Executive Incentive Compensation Plan. The Companies submitted evidence of the benefits provided to customers by their incentive compensation plans, in particular metrics contained within their Non-Executive Incentive Compensation Plan and the operational metrics contained within their Executive Incentive Compensation Plan. No party has opposed the recovery of the costs related to the Companies' Non-Executive Incentive Compensation Plans. This issue is not in dispute. The Commission approves the recovery of the Companies' expenses for their Non-Executive Incentive Compensation Plans.

Only for the purposes of narrowing the issues in this proceeding and without waiving any rights to contest such amounts in future proceedings, the Companies do not object to an adjustment removing their Omnibus Incentive Compensation Plan expenses from the test year operating expenses, consistent with the recommendations made by Staff, the AG, and CCI. This issue is not in dispute. The Commission approves an adjustment removing the costs of the Omnibus Incentive Compensation Plan expenses ($1,455,000 for Peoples Gas and $245,000 for North Shore) from the Companies' test year operating expenses.

With respect to the Executive Incentive Compensation Plan, only for the purposes of narrowing the issues in this proceeding and without waiving any rights to contest such amounts in future proceedings, both the Companies and CCI have agreed not to contest proposed disallowances to portions of the Companies' Executive Incentive Compensation Plan expenses as calculated by Staff. This disallowance is consistent with the adjustment proposed by the AG. This issue is not in dispute. The Commission approves an adjustment removing $4,216,000 for Peoples Gas' and $655,000 for North Shore's Executive Incentive Compensation Plan operating expenses.

b. Executive Perquisites

Only for the purposes of narrowing the issues in this proceeding and without waiving any rights to contest such amounts in future proceedings, the Companies do not object to an adjustment removing the amounts forecasted for executive perquisites included in test year operating expenses, but only for the amounts forecasted for these items in the 2015 test year – $44,000 for Peoples Gas and $7,000 for North Shore. This is not contested. The Commission approves an adjustment removing these amounts from the Companies' respective operating expenses.

c. Interest

(i) Budget Payment Plan

In rebuttal testimony, the Companies accepted Staff's adjustments of interest expense on budget payment plans based on the December 18, 2013, Commission ruling setting the 2014 rate of interest to be paid at 0%. This subject is uncontested. The Commission approves Staff's adjustments.

(ii) Customer Deposits

In rebuttal testimony, the Companies accepted Staff's adjustments of interest expense on customer deposits based on the December 18, 2013, Commission ruling setting the 2014 rate of interest to be paid at 0%. This subject is uncontested. The Commission approves Staff's adjustments.

(iii) Synchronization (including derivative adjustments)

In rebuttal testimony, the Companies accepted Staff's adjustments to interest synchronization. This subject is uncontested. The Commission approves Staff's adjustments.

d. Lobbying

In rebuttal testimony, the Companies accepted Staff's adjustments to disallow certain inadvertently included lobbying-related expenses. This subject is uncontested. The Commission approves Staff's adjustments.

e. Fines and Penalties

In rebuttal testimony, the Companies accepted Staff's adjustments to remove fines and penalties expenses. This subject is uncontested. The Commission approves Staff's adjustments.

f. Plastic Pipefitting Remediation Project (PGL)

In rebuttal testimony, the Companies accepted Staff's adjustment to disallow inadvertently included costs associated with the Plastic Pipefitting Remediation Project. This subject is uncontested. The Commission approves Staff's adjustments.

3. Other Production (PGL)

The Companies' proposed Other Production expense for Peoples Gas is not contested. The Commission approves the Companies' Other Production expense.

4. Storage (PGL)

The Companies' proposed Storage expense for Peoples Gas is not contested. The Commission approves the Companies' Storage expense.

5. Transmission

The Companies' proposed Transmission expense is not contested. The Commission approves the Companies' Transmission expense.

6. Distribution

The Companies' proposed Distribution expense is not contested. For Peoples Gas, this includes the three-year amortization recovery of costs associated with the Section 8-102 of the Act two-phase AMRP investigation as ordered in Docket Nos. 12-0511/12-0512 (Consol.). This subject is uncontested. The Commission approves the Companies' Distribution expense.

7. Customer Accounts – Uncollectibles

The Companies proposed that the net write-off method be used. Additionally, the Companies proposed that the bad debt expense at present rates as adjusted would be the average of the actual write-offs for calendar years 2010-2012, which was $22,648,000 for Peoples Gas and $1,105,000 for North Shore (and addressed the allocation of recovery between base rates and Rider UEA-GC, Uncollectible Expense Adjustment – Gas Costs). Staff agreed that its previously proposed adjustment to uncollectible expense and any resulting adjustments were not necessary and withdrew its proposed adjustment to uncollectible expense. The Commission approves the Companies' Customer Accounts – Uncollectible expense.

8. Customer Accounts – Other than Uncollectibles

The Companies' proposed Customer Accounts – Other than Uncollectible expense is not contested. The Commission approves the Companies' Customer Accounts – Other than Uncollectible expense.

9. Customer Services and Information

The Companies' proposed Customer Services and Informational Services expense is not contested. The Commission approves the Companies' Customer Services and Informational Services expense.

10. Administrative & General (other than items in Section V.C.3)

The Companies' proposed Administrative and General ("A&G") expenses are not contested with the exception of items addressed in Section V.C.3 of this Order. The Commission approves the Companies' A&G expenses.

11. Depreciation Expense (including derivative impacts other than in Section IV.C.1.a)

The Companies' proposed Depreciation expenses are not contested except for the impacts of the 2014 AMRP costs discussed in Section IV.C.1.a of this Order. The Commission approves the Companies' Depreciation Expense (including derivative impacts other than in Section IV.C.1.a of this Order).

12. Amortization Expense (including derivative impacts)

The Companies' proposed Amortization Expense is not contested. The Commission approves the Companies' Amortization Expense (including derivative impacts).

13. Rate Case Expense (other than amortization period in Section V.C.4)

Section 9-229 of the PUA provides:

> Consideration of attorney and expert compensation as an expense. The Commission shall specifically assess the justness and reasonableness of any amount expended by a public utility to compensate attorneys or technical experts to prepare and litigate a general rate case filing. This issue shall be expressly addressed in the Commission's final order.

220 ILCS 5/9-229. The Appellate Court in Illinois-American Water held that Section 9-229 requires the Commission to "'expressly address' the basis for its findings" – *i.e.*, include "explanation or discussion" – as to the justness and reasonableness of a public utility's rate case expenses in its final order. *Illinois-American Water*, 2011 IL App (1st) 101776 at ¶¶ 47-48. Based on the guidance provided by the court in Illinois-American Water, as confirmed by the ComEd decision, the Commission has stated that a public utility must provide detailed information concerning what actual expenses have been or will be incurred, by whom, for what purpose and why such expenses were necessary in order for the Commission to make an informed determination regarding the justness and

reasonableness of recovering rate case expenses from customers. *See Docket Nos. 12-0511/12-0512* (Consol.), Order at 174; *In re Charmar Water Co*., *et al*., Docket Nos. 11-0561 – 11-0566 (Consol.), Order at 19 (May 22, 2012); *In re Charmar Water Co.*, *et al*., Docket Nos. 11-0561 – 11-0566 (Consol.), Order on Rehearing at 14 (Nov. 28, 2012).

North Shore and Peoples Gas take the position that the evidentiary record contains substantial evidence demonstrating that their revised proposed rate case expenses for this rate case – $1.947 million for North Shore and $2.945 million for Peoples Gas – are just and reasonable. NS-PGL Ex. 21.0 at 14-15; NS-PGL Exs. 21.3N, 21.3P; NS-PGL Ex. 36.0 at 13; NS-PGL Exs. 36.4N and 36.4P; Staff Ex. 7.0 at 16 and Scheds. 7.06N, 7.06P. The Utilities assert that the record evidence is more than sufficient for the Commission to specifically assess the justness and reasonableness of those expenses as required by Section 9-229 of the Act, 220 ILCS 5/9-229. Staff agrees with the Companies on the total amount of rate case costs introduced into the record to support the recovery of their rate case expenses and that the amounts sought by the Utilities were just and reasonable. This issue is uncontested.

The Commission finds that for each of the attorneys and technical experts for which recovery of rate case expense is sought, the Utilities provided detailed information concerning the nature and scope of their engagement, their hourly rates, what services they performed in support of the rate case, why those services were necessary, and what their actual expenses have been or will be incurred. Detailed invoices were provided that identified who was performing the work, what work or tasks were performed, when and for how long, and the fees and costs associated with that work. Further, the record evidence demonstrates that the rates negotiated with the attorneys and experts were reasonable in light of their experience working on rate cases generally and for the Utilities specifically, the market rate for such services, discounts and other cost protections such as "not-to-exceed" provisions provided, and the necessity and level of difficulty of the work to be performed. The record evidence also established that the Utilities review the invoices and have other safeguards in place to ensure that there is no "double-counting" for the costs of work performed by Integrys Business Services ("IBS") personnel and that the time spent performing work by outside counsel and experts is reasonable and not duplicative. Moreover, while not determinative of the issue, the Commission notes that no party opposed recovery of the final revised amounts of rate case expenses sought by the Utilities, and that Staff testified it had reviewed the record evidence and found the amounts requested to be just and reasonable based on the facts and circumstances of this rate case.

Additionally, the Commission finds that the evidence in the record supports the conclusion that the amounts of rate case expenses not actually shown to have been expended by the time of the hearing are reasonably likely to be expended by the end of the rate case.

Further, the Commission approves the recovery of $521,000 for North Shore and $786,000 for Peoples Gas for their approved but unrecovered prior rate case expenses from their 2009 and 2011 rate case rehearings and their 2012 rate cases, as well as $118,000 for North Shore and $180,000 for Peoples Gas for their appeal costs from their 2012 rate cases.

The total rate case costs are detailed in NS-PGL Exs. 36.4N and 36.4P and are uncontested. However, the time period over which these rate case expenses will be amortized is contested. The Utilities request that these expenses be amortized over two years for ratemaking purposes. Staff proposes instead that the amortization period be changed to 2.5 years based on the proposed Reorganization pending approval in Docket No. 14-0496. This issue will be addressed below in Section V.C.4.

14. Taxes Other Than Income Taxes (including derivative impacts)

The Companies' revised proposed Taxes Other Than Income expense is not contested. The Commission approves the Companies' Taxes Other Than Income expense.

15. Income Taxes (including derivative impacts)

In rebuttal (North Shore) and surrebuttal (Peoples Gas) testimony, the Companies' revised the proposed Income Taxes expense. These expenses are uncontested except for derivative impacts of contested items. The Commission approves the Companies' Income Taxes expenses.

16. Reclassification of Costs to Plant in Service (PGL)

The Companies acknowledged in response to a Staff data request that they inadvertently omitted in Peoples Gas' rebuttal revenue requirement an adjustment to reclassify certain costs from O&M expense to Plant in Service. In surrebuttal testimony, the Companies' corrected this omission to show the reduction to O&M expense offset by derivative depreciation expense and income taxes on Plant in Service. This corrected Reclassification of Costs to Plant in Service is not contested. The Commission approves the Companies' Reclassification of Costs to Plant in Service.

17. Gross Revenue Conversion Factor

The Companies' Gross Revenue Conversion Factors ("GRCFs") are not contested. The Commission approves the Companies' GRCFs.

18. Other

As ordered by the *Docket Nos. 12-0511/12-0512 Order on Rehearing*, the Companies provided a status report in testimony at each stage of the rate case proceeding to identify any pending adjustments which required further instructions to calculate the impact of federal NOL on current and deferred income taxes. As indicated in Section IV.B.7.(b) of this Order, the Companies and Staff agreed that the stand alone federal NOLs and the related federal DTAs balances at the end of calendar year 2014 and test year 2015 are zero. Therefore, there are no pending adjustments to be identified that require further instructions to calculate the impact of federal NOLs on current and deferred income taxes.

The Companies accept Staff's adjustments to Invested Capital Tax ("ICT"), and thus there are no contested issues concerning the calculation of ICT. The Commission approves the final invested capital tax figures (including derivative impacts) based on the revenue requirement findings in the final Order.

There are no other issues related to operating expenses that are required to be discussed here.

C. Potentially Contested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Test Year Employee Levels

a. Peoples Gas

Peoples Gas' Position

Peoples Gas argues that its forecasted 2015 test year employee level should be approved but notes that the AG proposes an adjustment to this level based on the AG's assertion that the number of employees has been relatively steady through 2012 and 2013 and there is no discernible upward trend in the number of employees. The AG proposes a reduction to 1,319 full time equivalent ("FTE") employees, which would reduce the forecasted test year operation and maintenance expense by $1,904,000 and related payroll taxes by $129,000. Peoples Gas argues that the AG's adjustment is unsupported and should be rejected.

Peoples Gas forecasted an increase in its headcount from 1,306 FTE employees at the end of 2013 to 1,356 employees at the end of 2014 and throughout the entire 2015 test year. According to Peoples Gas, this forecast was based on an increased need for employees to address stricter standards of compliance with pipeline safety rules as well as increased work on AMRP. Peoples Gas states that although the AG's witness Mr. Effron admitted that he does not dispute that Peoples Gas will be hiring new employees from time to time he argued that the AG's significant adjustment is justified by the supposition that other employees will be simultaneously retiring or leaving for other reasons.

Peoples Gas contends that it has provided ample evidence to justify its increased test year employee levels – for example, Peoples Gas noted that a number of positions related to pipeline safety compliance and AMRP work have been recently filled. Additional detail regarding these positions, including identification of the pool of workers from which the positions are filled, was provided in the Companies' rebuttal testimony. Peoples Gas also identified thirty-three positions for which interviews were currently being conducted. In surrebuttal testimony, the Companies noted that approximately twenty positions will be filled by Utility Workers who graduated from the Power for America training program at Dawson Technical Institute in Chicago in September 2014. Peoples Gas states that it has created a well-founded expectation that members of the Power for America training program will be hired for permanent employment.

Peoples Gas counters that the AG allegations that Peoples Gas failed to indicate that students in the program had actually already started are unfounded and demonstrate a misunderstanding of the Dawson Technical Institute training program. Peoples Gas explains that graduating students are hired for a six-week internship program through the company with the goal of full time employment following the conclusion of the internship. Peoples Gas states that the AG's criticism is misplaced because Peoples Gas rightfully did not want to provide a premature update at the time of the hearings. Peoples Gas argues that the AG's adjustment does not take into account the recent additions to the Peoples Gas workforce, nor does it acknowledge the positions that are currently being filled. As explained by the Companies' witness Mr. Lazzaro, these Utility Workers participate in a six-week long internship through Peoples Gas, wherein the workers are assigned to a district shop and are evaluated by management staff, supervisors, and peers. As noted by Mr. Lazzaro, Peoples Gas seeks to hire those individuals who successfully complete the internship program as full-time utility workers.

Peoples Gas states that during the evidentiary hearings held on September 23, 2014, the AG entered certain cross-exhibits into the record reflecting Peoples Gas' actual employee levels as of December 2013 and July 2014. In doing so, the AG noted that the actual total FTE employee count as of December 2013 was 1,299.5, while the actual total FTE employee count as of July 2014 was 1,314.6. Although the AG correctly identified the actual employee levels for Peoples Gas in July 2014, the Companies emphasize that the AG's adjustment does not take into account Peoples Gas' planned hiring activities – in particular, the probable hiring of approximately 20 of the utility workers graduating from the Dawson Technical Institute training program, as identified and discussed in surrebuttal and in cross-examination. Peoples Gas asserts that it has clearly identified planned hiring practices in the near future, including the probable number of qualified and trained FTE employees.

Peoples Gas states that during the evidentiary hearings in this proceeding, the AG also introduced a discovery response related to certain proposed FTE employee commitments proposed in the WEC-Integrys transaction docket, Docket No. 14-0496. This discovery response indicated that testimony filed in the separate WEC-Integrys transaction docket, by a witness that has not appeared in the instant proceeding, committed to maintaining an overall minimum number of FTE employee positions in Illinois for two years after the closing of the transaction, showing 1,294 FTE employee positions through Peoples Gas within that minimum. This discovery response was additionally relied upon by CCI in its Initial Brief. The Companies argue that this information does not support the AG's nor CCI's proposed adjustments to headcount levels. As an initial matter, the WEC-Integrys transaction is subject to approval by the Commission and several other state and federal governmental agencies, and, if approved, it is not expected to close until Summer 2015. As such, the proposed commitment is subject to the proposed transaction, which has not yet been approved. In addition, the proposed commitment identifies a minimum number of FTE employee positions, but the response itself makes clear that the proposed commitment is for 1,953 FTE employees in Illinois, and not for the breakdown shown among Peoples Gas, North Shore, and IBS. The Companies emphasize that this point was acknowledged by the AG. The information from the WEC-Integrys transaction docket simply reflects a proposed commitment to maintain at least 1,953 FTE employees in Illinois – it does not preclude Peoples Gas from maintaining the forecasted 1,356 employees, for which Peoples Gas has identified a need. Moreover, the public announcements and data request responses do not indicate that employment levels would be decreased although potential reductions may occur due to natural attrition. The Companies argue that the Commission should reject this discovery response as not probative as to the proceeding at hand.

Peoples Gas states that although CCI did not address this issue in the rebuttal testimony of its witness, Mr. Gorman, CCI's Initial Brief reiterates the position expressed by the CCI witness in direct testimony. Like the AG, CCI relies upon Peoples Gas' historical employee levels, arguing that Peoples Gas' employee levels be reduced to match the Company's May 2014 actual levels. In addition, CCI also wholly disregards the evidence related to Peoples Gas' current and planned hiring practices.

Peoples Gas indicates that Staff agrees with Peoples Gas' forecasted employee levels, and notes that the adjustment proposed by the AG and CCI do not take into account Peoples Gas' recent and planned hiring. Peoples Gas concludes that the Commission should reject the adjustments proposed by the AG and CCI, and should adopt Peoples Gas' test year employee level.

<u>Staff's Position</u>

Staff submits that the Commission should reject AG witness Effron's and CCI witness Gorman's proposals to reduce the number of projected test-year employees based on analyses of historical trends. Staff maintains that while their analyses are logical to some extent, their arguments do not consider the Companies' recent hiring and do not refute the Companies' testimony regarding planned additional hiring.

<u>AG's Position</u>

Peoples Gas is forecasting 1,356 FTE employees for the 2015 test year. The AG states that despite this lofty goal, PGL's average level of FTE employees was around 1,302 in the first five months of 2014. This level is below the average actual FTE employment level of 1309.6 from the last six months of 2013. Additionally, the actual number of FTE employees in April and May of 2014, 1,298.5, was slightly lower than the average FTE employees in the first three months of 2014, 1,305.5. The AG states that the PGL employment level rose from May to July of this year, but only to 1,314.6. Moreover, as PGL witness Lazzaro confirmed in cross-examination, in each and every month from January through July of 2014, the actual FTE employment level was below the authorized level.

The AG asserts that in light of these trends, it is difficult to find credible the Company's forecast that it will actually fill its authorized employment level of 1,356 FTE employees by the end of 2014. Mr. Effron thus proposed in rebuttal testimony that PGL's test-year FTE employee level should be reduced to 1,319, the average for June and July of 2014. Mr. Effron's proposal would reduce PGL's test-year operation and maintenance expense by $1.904 million and related payroll taxes by $129,000.

The AG notes that in rebuttal testimony filed August 4, 2014, PGL witness Mr. Lazzaro stated, identically to Mr. Kinzle's rebuttal statement, that PGL's employee count at any moment is only a snap shot in time that does not reflect existing and future additions to employee count. Mr. Lazzaro then stated that Peoples has taken measures toward filling 33 open positions, bringing actual headcount up to forecasted test-year headcount and rendering Mr. Effron's proposed adjustment moot. The AG states that Mr. Lazzaro cited, for example, twenty utility workers from Dawson Technical Institute who will begin internships with the Company in September 2014. In cross-examination, though, Mr. Lazzaro admitted that the internship is merely a six-week evaluation by management and peers; permanent employment is not guaranteed. The AG continues that at no point during his surrebuttal testimony (filed September 12) or his cross-examination and re-direct examination (September 23) did Mr. Lazzaro indicate that the 20 Dawson Technical Institute students who purportedly would be starting work during September 2014 had actually already started.

The AG states that Mr. Lazzaro also referred in his rebuttal testimony to seven technician openings and nine supervisor openings (including three openings that will arise soon due to pending retirements) for which interviews are allegedly in process. The AG argues that given PGL's track record of not filling authorized employment levels the Commission should give a second or third thought to simply taking the Company's word that it will fill these openings. Moreover, even if the Company did fill the openings, attrition is also a significant consideration at Peoples Gas, as it is at North Shore. The Company hired 21 utility workers from Dawson Technical Institute in April 2014, but the number of Peoples Gas FTE employees decreased from 1,304.5 at the end of March 2014 to 1,298.5 employees at the end of April 2014 and then to 1,296.5 at the end of May 2014. Mr. Lazzaro admitted during cross-examination that attrition at the Company is generally positive. He also admitted that eight employees left the Company during July of 2014 due to some retirements and possibly a termination. The AG maintains that it is clear that the Company has to constantly hire more than attrition just to keep employment levels from falling. The AG continues that even if the Company had proven that it will hire enough new employees to fill currently authorized openings (which it has not), it must also show that it will additionally hire enough to keep up with attrition.

The AG concludes that in light of Peoples Gas' poor track record of filling authorized employment levels, Mr. Lazzaro failed to show with credible evidence that Peoples Gas will make new hiring net of attrition that will bring Peoples' 2015 test-year employment up to 1,356. The AG believes that the Commission should adopt Mr. Effron's downward adjustment.

<u>CCI's Position</u>

CCI submits that even though the utility forecasts an increased level of employees, PGL has seen a decline in its actual number of employees. For the period February 2014 to May 2014 the actual number of employees declined by 10. Furthermore, PGL actually has 60 fewer employees as of May 2014 (1,296) than it forecasted for May 2014 (1,356). PGL forecasts that it will employ 1,356 employees in the 2015 test year. CCI notes, however, that the record shows that during the historical period July 2013 through July 2014, PGL has never achieved its forecasted/authorized level of employees (1,356 employees) in any month of that period.

CCI states that PGL's actual employee levels have shown a decline (rather than the forecasted increase), they have persistently been less than forecasted by the PGL, and the Companies' projected merged staffing levels (for reorganization case commitments) are less than forecasted by PGL for setting rates. CCI proposes that the employee levels forecasted for the 2015 test year be reduced by 60 employees. That adjustment represents the difference between the actual May 2014 full-time employee levels and the full-time employee level PGL previously forecasted for the 2015 test year.

CCI argues that its proposed test year employee level of 1,296 employees actually exceeds (by two) the number of PGL employees the Companies have suggested will be kept in Illinois if their proposed reorganization (in Docket 14-0496) is closed. CCI asserts that this adjustment will reduce the PGL 2015 test year operating and maintenance payroll expense by $4 million.

Commission Analysis and Conclusion

The Commission agrees with Peoples Gas and Staff and approves Peoples Gas' forecasted 2015 employee levels. Peoples Gas offered detailed evidence regarding its current and planned hiring practices, and identified specific positions that are due to be filled. The Commission finds that the adjustments to Peoples Gas' forecasted 2015 FTE employee levels, as made by the AG and CCI, are unwarranted.

b. North Shore

North Shore's Position

North Shore contends that its forecasted 2015 test year employee level should be approved. North Shore notes that the AG proposes an adjustment to North Shore's forecasted 2015 test year employee level based on its assertion that the number of North Shore employees has been relatively steady through 2012 and 2013 and there is no discernible upward trend in the number of employees. The AG proposes that North Shore's 2015 test year payroll expense be reduced to reflect a January 2014 through May 2014 average employee count of 166 FTE employees, which would reduce the forecasted test-year operation and maintenance expense by $670,000 and related payroll taxes by $48,000. North Shore argues that the AG's adjustment is unsupported and should be rejected.

North Shore forecasted an increase in its headcount to 178 FTE employees throughout 2014 and 2015. In support of this forecast, North Shore noted that the proposed adjustments to the test year employee headcount do not take into account existing and future additions to employee count. North Shore provided evidence demonstrating that interviews were being conducted to fill thirteen open positions, and that an additional two positions were anticipated to be filled in the fourth quarter of 2014. In addition, North Shore noted that the increased employee levels are necessary and reasonable, as the company's current employee levels has forced it to operate at levels below the budgeted headcount, resulting in an inefficient reliance on overtime and contractors to supplement its workforce.

During the evidentiary hearings held on September 22, 2014, the AG entered certain cross-exhibits into the record reflecting North Shore's actual employee levels as of December 2013 and July 2014. In doing so, the AG noted that the actual total FTE employee count as of December 2013 was 164.7, while the actual total FTE employee count as of July 2014 had decreased to 163.68. Although the AG correctly identified the actual FTE employee count for North Shore, North Shore argues that these numbers do not take into account North Shore's expressed planned hiring goals for 2014. North Shore emphasizes that it is currently interviewing candidates for 13 open positions, four of which are for internal company construction inspector positions. North Shore states that it has clearly identified a need for additional FTE employees in specific positions that fill core functions of the utility.

North Shore notes that during the evidentiary hearings in this proceeding the AG also introduced a discovery response related to certain proposed FTE employee commitments proposed in the WEC-Integrys transaction docket, Docket No. 14-0496. As discussed with respect to Peoples Gas, this discovery response identifies a proposed commitment that is subject to approval of the WEC-Integrys proposed transaction. Moreover, the AG acknowledged that the proposed commitment as stated in the discovery response identifies a commitment for 1,953 FTE employees in Illinois, not for the breakdown among Peoples Gas, North Shore, and IBS. The AG further admits that the North Shore commitment is for a minimum of 166 FTE employees, which equals the number of employees forecasted by the AG. However, North Shore argues that the AG attempts to explain this fact away by arguing that the company-based employee figures must be based on some carefully calculated expectation for the test year. North Shore asserts that the AG introduced this data request, as issued in a separate docket by a witness that is not participating in the instant proceeding, and then attempts to explain away the numbers by assuming that there is some unknown, unidentified calculation that assumes that North Shore will not hire nor maintain additional employees to meet its forecasted 2015 test year FTE employee count. North Shore argues that the AG does not, and cannot, provide any evidence to rebut North Shore's prudent and reasonable 2015 forecasted employee levels, and that the Commission should reject the AG's adjustment.

North Shore adds that although CCI did not address this issue in the rebuttal testimony of its witness, Mr. Gorman, CCI's Initial Brief reiterates the position expressed by the CCI witness in direct testimony. The Companies state that, like the AG, CCI relies upon North Shore's historical employee levels, and wholly disregards the evidence related to North Shore's current and planned hiring practices.

Finally, North Shore notes that Staff agrees with North Shore's forecasted employee levels, and maintains that the adjustment proposed by the AG and CCI do not take into account North Shore's recent and planned hiring.

North Shore concludes that the Commission should reject the adjustments proposed by the AG and CCI, and should adopt North Shore's test year employee level.

<u>Staff's Position</u>

Staff argues that the Commission should reject AG witness Effron's and CCI witness Gorman's proposals to reduce the number of projected test-year employees based on analyses of historical trends. According to Staff, while their analyses are logical to some extent, their arguments do not consider the Companies' recent hiring and do not refute the Companies' testimony regarding planned additional hiring.

<u>AG's Position</u>

North Shore Gas is forecasting 178 FTE employees for the 2015 test year. The AG states that North Shore indicated in a discovery response and confirmed during the cross-examination of Mr. Kinzle that the Company's actual FTE employee level as of the end of December, 2013 was 164.7. As Mr. Effron noted in direct testimony, North Shore's actual FTE employees was stable at around 166 in the first five months of 2014. He further observed that the number of employees has been relatively steady through 2012 and 2013 and there is no discernible upward trend in the number of employees. Mr. Effron proposed reducing North Shore's test-year FTE employee level to 166.

In rebuttal, Mr. Effron noted that his proposed test-year level of 166 is actually higher than the actual number of North Shore FTE employees in June and July of 2014 – 163.68. The June and July 2014 actual FTE employment level at North Shore actually declined from levels prevalent at the end of 2013 and in early 2014. Mr. Effron's recommendation for the 2015 test-year employment level is "conservative" in favor of the Company. The AG states that Mr. Effron's proposal would reduce North Shore's test-year operation and maintenance expense by $670,000 and related payroll taxes by $48,000.

In rebuttal testimony filed August 4, 2014, North Shore witness Mr. Kinzle argued that North Shore's employee count is only a snap shot in time that does not reflect existing and future additions to employee count. He further stated that North Shore intends to hire additional employees in 2014, including thirteen in September and two more in the fourth quarter, which (after the departure of one summer intern), would theoretically bring North Shore's FTE employee count to 178 by year-end 2014. The AG states, however, that Mr. Kinzle admitted during cross-examination that, despite filing surrebuttal testimony in September of this year, he did not provide any update on the status of those purported thirteen new hires. Mr. Kinzle also admitted that historically, the Company's employee attrition is positive, and the net effect of new hires versus attrition is zero, which implies that any new hires that are actually effected in the latter part of 2014 may very well be balanced by an equal amount of employee departures. The AG adds that the Company also had an opportunity to provide a further update on the status of the purported thirteen new hires during re-direct examination, but declined to do so.

The AG finds that in light of North Shore's poor track record of filling authorized employment levels, Mr. Kinzle failed to show with credible evidence that North Shore will make new hiring net of attrition that will bring the Company's 2015 test-year employment up to 178. The AG states that the Commission should adopt Mr. Effron's downward adjustment.

The AG adds that in Docket No. 14-0496, the ICC proceeding for the merger application of Integrys and WEC, the Joint Applicants stated in a discovery response that they commit to preserve employment level in Illinois of 1,953 FTE employees for two years after the proposed July 2015 merger closing. The AG explains that the discovery response states that the commitment of 1,953 FTE employees is in the aggregate, and not for each company, but the company-based employment figures used to construct the aggregate commitment are telling, as they must be based on some carefully calculated expectation for the test year. The North Shore figure is equal to Mr. Effron's recommendation for the test year. Also, the Peoples figure in the Docket No. 14-0496 discovery response is below Mr. Effron's recommendation for the test year in this proceeding. According to the AG, these figures provide an additional reason for the

Commission to adopt Mr. Effron's downward adjustment to the Companies' forecasted test-year employment levels.

Furthermore, the AG submits that while Staff witness Kahle stated in his rebuttal testimony that he opposes Mr. Effron's proposal to reduce test-year employee levels because the proposal does not take into account planned additional hiring and recent additional hiring, he admitted that his only bases for this position were Mr. Lazzaro's testimony about PGL's plans for 21 additional hires before the end of this year and a discovery response not in the record. The AG argues that accepting the Companies' claims about future actions at face value is simply not a reasonable basis for agreeing with their positions.

The AG claims that Mr. Kahle had access to extensive data when he formulated his recommendations on this topic. He admitted that North Shore's actual FTE employment at the end of July 2014 was below the level at the end of December 2013 and that for each and every month of January through July, 2014, the actual FTE employment level was below the authorized level. Mr. Kahle also confirmed Peoples' actual FTE employment levels were under authorized FTE employment levels for each and every month from July 2013 through July 2014. Mr. Kahle then admitted that, while he was aware of these discrepancies at the time he formulated his rebuttal testimony, he merely considered current employee levels and the companies' plan, and did not project any history of actual budget differences in formulating his position. The AG maintains that in light of Mr. Kahle's failure to carefully analyze the credibility of the Companies' claims using available evidence, the Commission should not accept his recommendation.

The AG concludes that the Commission should adopt AG witness Effron's proposed adjustments to the test-year FTE employment levels of North Shore Gas from the Company's forecast of 178 down to a more reasonable level of 166.

CCI's Position

CCI claims that NS has seen a decline in its actual number of employees for the period August 2012 to May 2014 and adds that NS actually had 12 fewer employees as of May 2014 (165) than it had forecasted for May 2014 (177). NS forecasts that it will employ 177 employees in the 2015 test year. However, CCI claims that the record shows that for the historical period July 2013 through July 2014, NS has never achieved its forecasted/authorized level of 170 employees (in 2013) and 177-178 employees (in 2014) in any month of that time period.

CCI argues that historically NS employee levels appear to be declining, have actually been less than forecasted by the Company, and are projected to be less than forecasted by NS following the proposed reorganization. CCI proposes that the employee levels forecasted for the 2015 test year be reduced by 12 employees which is the difference between the actual May 2014 full-time employee levels and the full-time employee levels NS previously forecasted for the 2015 test year. CCI states that its recommended employee level of 165 is actually only one employee less than the Companies have suggested will be kept in Illinois, for NS, in the event the reorganization proposed in Commission Docket 14-0496 is closed. This adjustment will reduce the NS 2015 test year operating and maintenance payroll expense by $1 million.

Commission Analysis and Conclusion

The Commission agrees with North Shore and Staff and approves North Shore's forecasted 2015 employee levels. North Shore offered detailed evidence regarding its current and planned hiring practices, and identified specific positions that are due to be filled. The Commission finds that the adjustments to North Shore's forecasted 2015 FTE employee levels, as made by the AG and CCI, are unwarranted.

2. Medical Benefits

a. Peoples Gas

Peoples Gas' Position

The Companies state that the AG fails to provide any credible basis for its attempt to reject the Companies' medical benefits costs which are properly based on an independent actuarial report. Throughout the record, the Companies have provided evidence explaining how the Companies' figures are based on an independent actuary report, and detailing the supporting calculations that were supplied to Staff and intervenors. The Companies state that independent actuarial reports have regularly been relied upon by the Commission in numerous rate cases, for many years. The Companies note that AG witness Mr. Effron argued for use of the most current actuarial study to set pension expense in *Illinois Power Co*., Docket No. 91-0147, 1992 Ill. PUC Lexis 97, 177-178 (Feb. 11, 1992). The Companies assert that Mr. Effron was successful in that case and the Commission there found arguments against use of the study "too speculative" just as it should do so here.

The Companies indicate that while Mr. Effron argued against rejection of an actuarial study in Illinois Power Co., in the current cases he and the AG argue that the independent actuary report that was used to provide the foundation of the Companies' forecasts is not enough. The Companies state that Mr. Effron has provided no credible evidence that explains why the independent actuary's figures should not be relied upon by the Commission and has not articulated any way in which the actuarial report is flawed. The Companies argue that this is critical because they are not claiming that an actuarial report can never be rejected, but rather that sufficient grounds must be presented before rejecting a traditionally accepted report that has been supported in the evidence.

The Companies continue that Mr. Effron's position rests on nothing more than his personal opinion that based on the rate of medical cost increases from 2012 to 2013, the independent actuary's estimate of how medical benefits costs will increase by 2015 must be unreasonable. The Companies argue that this is not a valid basis for rejecting the independent actuary report and reducing medical benefits costs, and merely speculation.

The Companies maintain there is no credible or relevant evidence supporting Mr. Effron's opinion, and the AG points to no independent evidence suggesting a lower rate of medical benefits costs increases. The AG has not presented any valid reason to reject the independent actuary's figures, which are based on trend information, properly reflects changes in numbers of employees, and are consistently and correctly calculated.

The Companies add that Staff also opposes the AG's proposed medical benefits adjustments and shares nearly identical sentiments with the Companies. The Companies continue that the AG had the opportunity to cross-examine Staff witness Mr. Kahle regarding the reasonableness of the Companies' proposed medical benefits figures that were based on the independent actuary's figures. However, the AG's questions essentially assumed away the independent actuary report, which makes them irrelevant and of no probative value.

AG's Position

The AG states that PGL is forecasting an increase in medical benefits costs from $9,059,000 in 2012 to $13,892,000 in 2015, an increase of 53%. AG witness Effron testified that while medical costs did increase, those amounts are nowhere near the average annual rate of increase from 2012 to 2015 projected by PGL. The AG asserts that the forecasted 2015 medical benefits costs of $13,892,000 in 2015 still represents an increase of 43% over the actual 2013 medical benefits costs. The AG claims that while it may not be unreasonable to expect some increase in medical benefits costs from 2013 to 2015, the Companies were unable to justify a forecasted increase of 43% over a two-year period is reasonable.

The AG argues that in order to recognize a normalized amount of Medical Benefits expense in the test year, Mr. Effron applied a reasonable annual escalation factor to the actual 2013 medical benefits costs to project the 2015 test-year costs. The Companies explained that they applied certain escalation rates in response to the AG's discovery. According to NS Exhibit 12.0, Page 6, North Shore escalated 2013 medical cost per FTE employee by 4.9% for 2014 and 8.0% for 2015 to determine the projected rate for 2015. In Data Request PGL AG 1.51, the Companies were asked to provide supporting documentation for the projected 8% increase from 2014 to 2015. The response was provided in a one-sheet attachment titled "2013 rate development methodology and assumptions," with three lines showing an "Annual trend" of "8.5%, 6% prescription drug, and 5% dental." The cover sheet explained that the 8% trend was a blend of the 8.5% and the 6% prescription drug escalation rates. In Mr. Effron's opinion, this is not adequate justification for an increase of 8% from 2014 to 2015. Accordingly, he recommended that a more reasonable and data-based annual escalation rate of 4.9% be applied to the actual 2013 medical benefits for two years to project the 2015 test-year medical benefits expense.

The AG explains that the effect of Mr. Effron's proposed modification to the projection of PGL 2015 test-year medical costs is to reduce test-year medical benefits costs by $3,239,000. This adjustment was modified in Rebuttal testimony to incorporate employee increases from 2013 to 2014 for Peoples Gas. A similar adjustment to IBS medical benefits charged to Peoples Gas was also made. On his Ex. 7.2, Schedule DJE PGL C-2, Mr. Effron adjusted the projected increase in Peoples Gas benefits to reflect an increase of the employee complement of 1.8% in 2014 over the employee complement in 2013. On his Ex. 7.2, Schedule DJE PGL C-3, he adjusted the projected increase in IBS medical benefits charged to Peoples Gas to reflect an increase of 1.4% above the wage rate related increase in labor charged from IBS to Peoples Gas.

The AG states that in response to these adjustments, NS/PGL witness Hans offered several criticisms of Mr. Effron's proposed adjustments, but no substantive justification for the magnitude of the increases being forecasted by the Companies. The only explanation provided is that the forecasts are based on estimates from the Companies' actuaries. The AG asserts that statement in no way explains why the Companies are forecasting an increase in medical benefits of 43% for PGL over that two year period, an increase of 52% from 2013 to 2015 for North Shore, and a 31% increase for their affiliate, IBS, over the same period. The AG continues that Ms. Hans offers no explanation of any factors or trends that could reasonably account for increases of those magnitudes. Ms. Hans describes the process for calculating medical benefits expenses but she does not explain why the excessive increases should be incorporated into the determination of test year medical benefits expenses.

The AG concludes that Mr. Effron's more reasonable forecast of Medical Benefits for the test year should be adopted by the Commission.

Commission Analysis and Conclusion

The Commission agrees with Peoples Gas and finds that it provided extensive evidence supporting approval of its medical benefits costs. The Commission has relied upon actuarial reports during rate cases in the past and absent a proven flaw in such a report, which the AG has failed to mention, the Commission will not ignore such a report. The Commission rejects the AG's proposal and adopts Peoples Gas' proposed medical benefits expense.

b. North Shore

Company's Position

The Companies state that the AG's arguments as to North Shore's medical benefits costs parallel the AG's arguments as to Peoples Gas medical benefits costs, lack any valid basis, and should be rejected for the same reasons. *See* Section V.C.2.a of this Order.

AG's Position

The AG states that like the adjustment to Medical Benefits for Peoples Gas, Mr. Effron's adjustment to North Shore's forecasted test year level is significantly and inexplicably overstated. NS is forecasting an increase in medical benefits costs from \$1,329,000 in 2012 to \$1,927,000 in 2015, an increase of 45%. Based on the response to DR NS AG 1.42, the medical costs actually decreased from \$1,329,000 in 2012 to \$1,271,000 in 2013. Thus, the forecasted 2015 medical benefits costs of \$1,927,000 in 2015 represent an increase of 52% over the actual 2013 medical benefits costs. The AG asserts that while it may not be unreasonable to expect some increase in medical benefits costs from 2013 to 2015, Mr. Effron testified that he did not believe that a forecasted increase of 52% over a two-year period is reasonable.

Once again, he recommended that a reasonable escalation factor be applied to the actual 2013 medical benefits costs to project the 2015 test-year costs. North Shore's forecasted 2013 medical cost per FTE employee was escalated by 4.9% for 2014 and 8.0% for 2015 to determine the projected rate for 2015. Again, no additional supporting documentation was forthcoming from the Company in response to the aforementioned DR PGL AG 1.51. The same aforementioned one-sheet attachment titled "2013 rate development methodology and assumptions," with three lines showing an "Annual trend" of “8.5%, 6% prescription drug, and 5% dental” was provided. Again, as Mr. Effron noted, this is not adequate justification for an increase of 8% from 2014 to 2015. He therefore recommended that an annual escalation rate of 4.9% be applied to the actual 2013 medical benefits for two years to project the 2015 test-year medical benefits expense.

The AG states that the effect of Mr. Effron’s proposed modification to the projection of NS 2015 test-year medical costs results in a $528,000 to 2015 test-year medical benefits costs and results in a reduction of $418,000 to medical benefits costs charged to 2015 test-year operation and maintenance expenses. In Rebuttal testimony, Mr. Effron noted that there has been no increase in the North Shore employee complement since 2013, and, therefore, no modification of his proposed adjustment to the North Shore test-year medical benefits expense is necessary. He added that even though there has been a slight increase in the number of IBS employees in 2014 over 2013, there has been no increase in the IBS labor expense allocated to North Shore in 2014. As benefits expense should follow the labor expense, Mr. Effron testified that no increase in IBS medical benefits should be charged to North Shore.

The AG maintains that the Commission should adopt AG witness Effron’s more reasonable representation of forecasted Medical Benefits expense in the PGL and NS test years.

Staff’s Position

Staff argues that the Commission should reject AG witness Effron’s proposed adjustment to reduce the amount of projected direct medical benefit costs and medical benefits allocated from IBS based on applying an inflation factor to historical costs. Staff asserts that Mr. Effron’s linear analysis does not allow for consideration of the Companies’ projected increases in the number of employees or the Companies’ independent study of claims.

Staff states that should the Commission determine to reduce the number of projected test-year employees, however, there should be a related reduction in projected direct medical benefit costs.

Commission Analysis and Conclusion

The Commission agrees with North Shore and finds that it provided extensive evidence supporting approval of its medical benefits costs. The Commission has relied upon actuarial reports during rate cases in the past and absent a proven flaw in such a report, which the AG has failed to mention, the Commission will not ignore such a report. The Commission rejects the AG’s proposal and adopts North Shore’s proposed medical benefits expense.

3. Other Administrative & General

a. Integrys Business Support Costs

(i) Labor

Companies' Position

The Companies state that their cost figures reflect properly forecasted IBS labor costs cross-charges. The Companies note that AG witness Mr. Effron's proposals to reduce the level of these costs are inconsistent and without merit. The Companies proffer that while the issue to be addressed should be whether the forecasted level of IBS labor costs to be cross-charged in 2015 is reasonable, the AG proceeded as if the true issue was determination of the level of costs or the IBS headcount as of some point in 2014.

The Companies maintain that Mr. Effron's proposals were based on his analysis of data from 2012, 2013, and the first four months of 2014. However, he used one method for Peoples Gas (his figure is based on the 2013 expense level with a wage increase level based on two years of the average wage increase level from 2012 to 2015) and a different one for North Shore (his figure is based on the 2013 expense level with a wage increase level based on one year of the average wage increase level from 2012 to 2015). He also did not take into account any other factors that impacted labors costs between 2013 and 2015.

The Companies contend that Mr. Effron's direct testimony proposal ignored the three primary reasons that these labor costs were forecasted to increase: (1) the increased services provided to the Companies and the requisite increases in IBS labor to provide those services, (2) increased FTE employees at IBS, and (3) a proper shift in the allocation percentages. The Companies note that Mr. Effron's rebuttal proposal did not correct for any of the above flaws in his direct testimony proposal. In fact, during rebuttal, the only change made by Mr. Effron was to correct for his using incorrect allocation percentages, and to calculate the Peoples Gas figure by escalating 2013 costs based on the rate of increase in the first six months of 2014.

The Companies state that the AG points to the percentage increases in cross-charged labor costs from 2012 to 2013, but the AG does not show how that is relevant. According to the Companies, the issue is 2015. The AG argues that Mr. Effron's proposal is reasonable as to North Shore on the grounds that the actual labor expense in the first four or six months of 2014 was lower than in the same period of 2013, and that it is reasonable as to Peoples Gas on the grounds that, while the actual labor expense in the first four months of 2014 was higher than in the same period of 2013, the rate of increase in those four months was less than was forecasted. Again, the Companies note that the issue is 2015.

The Companies assert that the AG's repeated reliance in cross-examination and later in briefing on data extrapolated from specific and limited periods from 2012, 2013 and 2014 simply serves to confirm certain mathematical calculations that reflect the increase in costs between specific years. The Companies note that the AG entered several cross-exhibits into the record, purportedly in support of the AG's claim that the forecasted test year amounts of labor expense charged by IBS to North Shore and

Peoples Gas is excessive and unjustified. However, the Companies contend that these cross-exhibits simply reflect cost information, and nothing more. The Companies explain that this financial information is not relevant to the forecasted 2015 costs, and does not provide any support for the AG's inconsistent and meritless proposals.

Finally, the Companies maintain that neither of the AG's arguments takes into account the three points noted above from the rebuttal of Companies' witness Ms. Kupsh regarding why the 2015 costs are forecasted to be higher. The AG's response to this subject is circular. Additionally, the AG admits that Mr. Effron's proposals did not "explicitly" address those three points, but claims that his looking at data from 2012, 2013, and the beginning of 2014 somehow implicitly took them into account. That argument assumes, without any identified factual basis, that that data fully reflects those three factors.

The Companies add that Staff opposes the AG's proposals and recommends that they not be adopted. The AG attempts to weaken Staff's testimony, but all the AG demonstrates is that Staff witness Mr. Kahle, in concluding that the 2015 forecasted level is reasonable, did not perform an "independent analysis" of whether the three factors cited by Ms. Kupsh already have resulted in increases, and did not assess whether the costs have been increasing in the recent past.

The Companies contend that, as a result of the AG's deficiencies in evidence and lack of meritorious proposals, the Companies' well-supported figures should be adopted, as both the Companies and Staff contend.

<u>Staff's Position</u>

Staff submits that the Commission should reject AG witness Effron's proposed adjustment to reduce the amount of IBS O&M cross charges for labor for both Companies. Mr. Effron's analysis increases historical costs by a general wage increase factor. The Companies demonstrate three factors that account for the additional increases: an increase in direct charges from IBS related to increased services; an increased number of employees; and a change in the allocation percentages based on the increased number of employees and total spending. Staff finds that while Mr. Effron's analysis is logical, it does not refute the Companies' testimony supporting the increases.

Staff states that should the Commission determine to reduce the number of projected test-year employees, however, there should be a related reduction to cross charges for labor for both Companies.

<u>AG's Position</u>

The AG argues that the forecasted test year amounts of labor expense charged by IBS to North Shore and Peoples Gas is excessive and unjustified. The 2015 test-year O&M expense includes $7,630,000 of labor expense charged by IBS to North Shore, an amount that AG witness Effron testified was unreasonably high and unsupported. He explained that the forecasted $7,630,000 expense represents an increase of 17% over the actual 2012 expense. NS/PGL witness Tracy Kupsch did not dispute that calculation. But based on the response to Data Request NS AG 1.51, the actual IBS cross-charged labor expense to North Shore decreased from $6,521,000 to $6,330,000 in 2013. The

AG notes that the response to Data Request NS AG 7.05 shows the cross-charged labor expense to NS in the first four months of 2014 was actually less than the expense in the corresponding period in 2013. Based on this actual experience, the projected increase in labor expense to the 2015 test year is clearly overstated and should be modified. The AG continues that AG Cross Ex. 2 shows that the IBS labor charged to North Shore was forecasted to increase by approximately 8.8 percent from 2013 to 2014.

AG witness Effron recommended that the actual 2013 expense be used as a base to project the 2015 test-year labor expense, and further that the 2014 IBS labor expense charged to North Shore be assumed to be the same as the 2013 expenses. The AG asserts that this assumption should be considered a conservative one because the expense in the first six months of 2014 was actually lower than the expense in the first four months of 2013.

The AG states that the actual labor expense in 2013 was $6,331,000. The response to Data Request NS AG 3.01 shows that the forecast of 2015 cross-charged labor expense includes the effect of $740,000 of wage rate increases from 2012 to 2015. This translates into an average increase in wage rates of 3.78% per year. Application of this increase to the assumed 2014 labor expense of $6,331,000 results in a projected 2015 labor expense of $6,570,000. This is $1,060,000 less than the $7,630,000 of labor expense forecasted by NS. The AG believes that the NS test-year operation and maintenance expense should be adjusted accordingly.

For Peoples Gas, the forecasted PGL 2015 test-year O&M includes $45,781,000 of labor expense charged by IBS. The AG states that this forecasted labor expense amount, too, is unreasonable. Mr. Effron explained that the forecasted $45,781,000 expense represents an increase of 21% over the actual 2012 expense, a number NS/PGL did not dispute. But based on the response to DR PGL AG 1.59, the actual IBS cross-charged labor expense to PGL increased by only 0.5% from 2012 to 2013, well below the rate of increase forecasted by PGL. The AG states that the response to DR PGL AG 7.07 shows an increase in the cross-charged labor expense to PGL in the first four months of 2014 over the corresponding period in 2013, but at a lower rate than the increase forecasted by PGL from the actual 2013 labor expenses to 2014. The AG argues that based on this actual experience, the projected increase in labor expense to the 2015 test year is overstated and should be modified.

Mr. Effron testified that the actual 2013 expense be used as a base to project the 2015 test-year labor expense charged to Peoples, similar to his adjustment for North Shore. The actual labor expense in 2013 was $37,895,000. The response to Data Request PGL AG 3.10 shows that the forecast of 2015 cross-charged labor expense includes the effect of $4,281,000 of wage rate increases from 2012 to 2015. This translates into an increase of 3.79% per year. Application of this increase in both 2014 and 2015 to the actual 2013 labor expense of $37,895,000 results in a projected 2015 labor expense of $40,818,000 charged to PGL. This is $4,963,000 less than the $45,781,000 of IBS labor expense forecasted by PGL.

The AG notes that the Companies' witness Ms. Kupsh disagreed with Mr. Effron's proposed adjustments to IBS cross-charged labor expenses. First, she stated that Mr. Effron did not allow for increased services provided to Peoples Gas and North Shore from

IBS. Second, she stated that he did not consider increased FTE employees at IBS. Third, she stated that he did not consider shifts in the allocation percentages based on utility inputs.

The AG asserts that these criticisms were invalid. While Mr. Effron agreed that he did not explicitly address each of the listed factors in his direct testimony, he did look at the actual increases in IBS cross-charged labor from 2012 to 2013 and the IBS cross-charged labor in the available months in 2014 compared to the corresponding period in 2013. Mr. Effron explained to the extent that the factors cited by Ms. Kupsh actually affected the IBS cross-charged labor expenses, the effects of those factors are implicitly included in the actual expenses in 2013 and 2014 to date. The AG notes that Ms. Kupsh's analysis fails to explain why actual increases in IBS cross-charged labor expenses have so far been significantly less than the increases forecasted by the Companies.

The AG contends that the cross-charged labor expense to North Shore in the first four months of 2014 was actually less than the expense in the corresponding period in 2013, and the cross-charged labor expense to Peoples Gas increased in the first four months of 2014 over the corresponding period in 2013, but at a lower rate than the increase forecasted. Based on the updated response to Data Request NS AG 16.04, the cross-charged labor expense to North Shore in the first six months of 2014 was still less than the expense in the corresponding period in 2013. The cross-charged labor expense to Peoples Gas in the first six months of 2014 was 5.19% greater than the expense in the corresponding period in 2013, only 1.4% more than the increase related to changes in wage rates. The AG submits that regardless of the underlying reasons for the increases in cross-charged labor being forecasted by the Companies, those increases simply are not taking place.

The AG adds that while Staff witness Daniel Kahle testified that he endorsed the Companies' IBS-charged labor forecast, he admitted that he did not perform any independent analysis to determine whether those three factors cited by the companies have actually resulted in increases to IBS cross-charged labor expense. He also admitted that he did not assess whether the available evidence or data from discovery indicates that the actual IBS cross-charged labor expenses have been increasing in the recent past.

The AG notes that Mr. Effron did, however, make one modification to his proposed adjustments to IBS-charged labor Peoples Gas (but not North Shore). As the actual increase in cross-charged labor expense to Peoples Gas in the first six months of 2014 was slightly greater than the increase related solely to wage rate changes, he instead used the actual six-month increase of 5.19% to project the cross-charged labor expense for 2014 and 2015. That results in a proposed reduction of $3,851,000 to labor cross changed from IBS to Peoples Gas. The AG explains that as the cross-charged labor expense to North Shore in the first six months of 2014 was less than the expense in the corresponding period in 2013, there was no need to modify his proposed adjustment to cross-charged labor expense to North Shore.

Commission Analysis and Conclusion

The Commission agrees with the Utilities and Staff and finds that the Utilities have provided sufficient evidence in support of their forecasted IBS labor costs cross charges.

The Commission also acknowledges that the AG analysis does not take into account various factors that impacted the increase in labor costs between 2013 and 2015 such as the increased services provided to the Utilities and the requisite increases in IBS labor to provide those services, the increased FTE employees at IBS, and a shift in the allocation percentages. The Commission finds that the record supports the Utilities' forecast and rejects the AG's proposals.

(ii) Benefits

Companies' Position

The Companies state that the AG's proposed adjustments to medical benefits cross-charged by IBS in all but one respect parallel the AG's arguments as to Peoples Gas' and North Shore's medical benefits costs, lack any valid basis, and should be rejected for the same reasons. *See* Section V.C.2.a of the Companies' Position above.

The Companies state that the new item that is added here by the AG is that Mr. Effron originally included a component in his proposed adjustments relating to the percentage of IBS medical benefits costs cross-charged to the Companies. However, after the Companies pointed out that Mr. Effron had not used the right percentages, he corrected his adjustments as to this aspect in his rebuttal. The Companies submit that the final paragraph of the AG's Initial Brief's discussion seems to suggest this aspect still is contested, but that it not the case.

The Companies contend that their figures should be adopted and notes that Staff agrees.

Staff's Position

Staff argues that the Commission should reject AG witness Effron's proposal to apply allocation percentages from 2013 to 2015 projected costs. Staff claims that percentages used to allocate 2015 projected costs should be based on the allocation base, such as the number of employees, approved by the Commission, for the period in which the costs are incurred.

AG's Position

The AG states that the test-year O&M expenses for both companies include employee benefit costs billed from IBS. IBS benefits billed are included in total employee benefits expense. The NS 2015 test-year IBS benefits billed expense is $1,868,000, and the PGL 2015 test-year IBS benefits billed expense is $11,250,000. The 2015 IBS benefits allocated to NS represent 6.6% of the total 2015 IBS benefits expense of $28,300,000. The 2015 IBS benefits allocated to PGL represent 39.8% of the total 2015 IBS benefits expense.

The AG explains that AG witness Effron proposed to adjust the forecasted IBS benefits expense allocated to NS and PGL in two separate adjustments. First, he modified the forecast of medical benefits expense. Second, he proposed modifying the percentages of IBS benefits expenses charged to NS and PGL.

Mr. Effron's proposed adjustment to the forecast of IBS medical benefits costs is similar to the adjustments to NS and PGL medical expenses. According to NS and PGL

Exhibits 12.1, IBS medical benefits costs are forecasted to increase from $9,808,000 in 2012 to $12,552,000 in 2015, an increase of 28%. But based on the response to Data Request PGL AG 1.53, the medical costs actually decreased from $9,808,000 in 2012 to $9,554,000 in 2013. Thus, the forecasted 2015 medical benefits costs of $12,552,000 in 2015 represent an increase of 31% over the actual 2013 medical benefits costs. The AG argues that while it may not be unreasonable to expect some increase in medical benefits costs from 2013 to 2015, it is unreasonable to forecast an increase of 31% over a two-year period in light of the data.

The AG states that Mr. Effron recommended that a reasonable escalation factor be applied to the actual 2013 medical benefits costs to project the 2015 test-year costs. Mr. Effron recommended that a 4.9% annual escalation rate be applied to the actual 2013 medical benefits for the purpose of projecting the 2015 test-year medical benefits expense. Mr. Effron's proposed modification to the projected IBS 2015 test-year medical costs reduces test-year medical benefits costs to $10,513,000 for the 2015 test year. The AG maintains that this is $2,039,000 less than the medical benefits costs projected by the Companies for IBS.

The second adjustment relates to the percentages of IBS benefits expenses charged to NS and PGL. NS Exhibit 12.2 and PGL Exhibit 12.2 show the allocation of IBS benefits expenses to NS and PGL. Both of these exhibits show increases from the actual 2012 allocation percentages to the forecasted 2015 allocation percentages, with the greatest increases taking place from 2013 to 2014. The AG states that in Data Requests AG NS 1.48 and AG PGL 1.56, the Companies were asked to explain the forecasted increases in the allocation percentages from 2013 to 2014. The Companies provided a brief description of the method used to allocate IBS benefits expenses to NS and PGL and also provided what they described as the actual allocation ratios for 2013, stating that the allocation percentages from IBS to NS and PGL have not changed significantly from actual 2013 to forecast 2014.

The AG asserts that the allocation percentages for 2013 in the responses to DRs AG NS 1.48 and AG PGL 1.56 are inconsistent with the actual allocation percentages in the responses to Data Requests AG NS 1.45 and AG NS 1.53. In the response to AG NS 1.48, the Company stated that the allocation percentage for NS in 2013 was 6.5%. The actual allocation percentage in the response to AG NS 1.45 is 5.7%. According to the AG, the forecasted allocation percentage of 6.5% for 2014 is a significant increase from the actual 2013 allocation percentage, which NS has not explained.

In the response to AG PGL 1.56, the Company stated that the allocation percentage for PGL in 2013 was 39.0%. The actual allocation percentage in the response to AG PGL 1.53 is 34.1%. The AG states that the forecasted allocation percentage of 39.0% for 2014 is a significant increase from the actual 2013 allocation percentage, which PGL also has not explained.

The AG asserts that the actual 2013 allocation percentages for 2013 represent decreases from the actual 2012 allocation percentages. The AG notes that the Company had forecasted decreases from 2012 to 2013, but the actual decreases were greater than forecasted. The Companies have not justified the jumps in the allocation percentages from 2013 to the forecasted 2014 allocation percentages, which approximate the forecasted 2015 test-year allocation percentages. The AG contends that the forecasted 2015 test-year allocation percentages should be modified.

The AG explains that to reflect the actual activity AG witness Effron recommends that the actual 2013 allocation percentages be used to allocate the IBS benefits expense to NS and PGL. The actual 2013 allocation percentages are 5.7% for NS and 34.1% for PGL.

The AG notes that NS/PGL witness Kupsh disagreed with Mr. Effron's proposed adjustments to IBS cross-charged benefits expenses. She opined that the 2013 actual allocation percentages and the forecasted 2015 allocation percentages that Mr. Effron relied on in his direct testimony to quantify his proposed adjustments were not stated on comparable bases. She stated that using comparable bases, the actual allocation percentage for North Shore in 2013 would be 6.2%, rather than 5.7%, and the actual allocation percentage for Peoples Gas in 2013 would be 37.4%, rather than 34.1%.

The AG states that Mr. Effron agreed that the actual percentage allocation factor in 2013 should be calculated on a basis consistent with the calculation of the allocation factor for the 2015 test year, and modified his calculation of the adjustment to the 2015 IBS cross-charged benefits accordingly. When combined with the adjustment to the Medical portion of the Benefits, the adjustment to the allocator results in adjustments of $1,258,000 for PGL and $228,000 for North Shore.

The AG asserts that the Companies failed to justify use of a percentage allocator that is inconsistent with actual activity and submits that Mr. Effron's adjustment should be adopted by the Commission.

<u>Commission Analysis and Conclusion</u>

The Commission agrees with the Companies and Staff and finds that for the same reasons discussed in the Commission Analysis and Conclusion section in Section V.C.2.a of this Order, the AG's proposed adjustments to medical benefits expense, including medical benefits cross-charged by IBS, should be rejected.

(iii) Postage

<u>Companies' Position</u>

The Companies state that the AG's proposed adjustments to the Companies' forecasted cross charged postage expense are incorrect and should be rejected. The AG's proposal considers only a flat postage rate increase, and ignores the expected increase in volume of mail, which is driven by the ICE project. The Companies note that Staff also opposes the AG's postage adjustments.

The Companies state that the AG calls the forecasted 2015 level of this expense "unexplained", but this is nothing more than the AG seeking to define away the expected increases in postage rates and volume of mail as explanations. The Companies maintain that the AG admits that those two factors could increase the expense level, although the AG claims that the Companies did not sufficiently explain how they will result in the forecasted levels.

The Companies add that the AG seeks to diminish the fact that Staff witness Mr. Kahle agrees with the Companies' figures and opposes the AG's proposed adjustments, by pointing to the fact that he did not do an "independent analysis" of the likelihood of the volume increases. The Companies maintain that does not alter the fact that Mr. Kahle's review led him to conclude that the Companies' figures should be approved. Additionally, Mr. Kahle's rebuttal testimony made clear that he had reviewed the Companies' support for the increases.

The Companies contend that the AG cannot ignore the effect of the expected increases in postage rates and the increase in the volume of mail on the Companies' forecasted cross charged postage expense. The Companies submit that their figures should be adopted.

Staff's Position

Staff argues that the Commission should reject AG witness Effron's proposal to reduce postage expense charged to the Companies from IBS. Staff notes that Mr. Effron considers the amount of the proposed increase to be unreasonable, but does not make an argument against the Companies' rationale for the proposed increase. The Companies propose increasing postage expense because of an expected increase in the volume of mailings as well as a postage rate increase. According to Staff, the Companies' rationale is reasonably based on the support provided for the increase.

AG's Position

The AG explains that IBS allocates postage expense to both NS and PGL. NS test-year operation and maintenance expenses include $914,000 of postage expense allocated from IBS. PGL test-year operation and maintenance expenses include $4,799,000 postage expense allocated from IBS.

The AG states that AG witness Effron proposed to adjust the test-year postage expenses based on the Companies' unexplained and inflated forecasted 2015 postage expense. For NS, the allocation represents an increase of 38% over the actual postage expense of $648,000 in 2013. The forecasted 2015 postage expense for PGL represents an increase of 20% over the actual postage expense of $4,170,000 in 2013. The AG asserts that projected increases of this magnitude over two years are not reasonable. Mr. Effron noted that while it would not be unreasonable to include a small allowance for increases in postage rates from 2013 to 2015, allowances should be no more than 10%, based on annual increases in postage rates in recent years. Mr. Effron calculated that escalating the actual 2013 postage expense by 10% would result in a reduction of $201,000 to the NS forecasted 2015 test-year postage expense and $212,000 to the PGL forecasted 2015 test-year postage expense.

The AG notes that NS/PGL witness Kupsh disagreed with the AG-proposed postage expense adjustments. She claimed that Mr. Effron did not allow for increases in volume, such as increases related to ICE project-related volume. But Ms. Kupsh never explained how the increases in volume will result in the specific increases in postage expense that the Companies are now forecasting. The AG adds that Ms. Kupsh cites factors that could potentially increase postage in volume, but she does not show how such increases in volume would lead to the magnitude of increases reflected by the

Companies in their forecasts of 2015 test-year postage expenses. The AG states that Ms. Kupsh appears to be claiming that the projected increases are reasonable because that is what the Companies forecasted. The AG contends that the Companies simply did not provide the necessary detail and document the forecasted increases in postage expenses to justify the forecasted increases.

The AG notes as well that Staff witness Kahle endorsed the Companies' forecasts, but conceded during cross examination that he simply relied on the Companies' numbers and conducted no independent analysis of his own. The AG submits that Mr. Effron's well-supported adjustments, based on actual data, should be adopted by the Commission.

Commission Analysis and Conclusion

The Commission approves the Utilities' forecasted cross charged postage expense. The Commission agrees with the Utilities and Staff that the effect of the expected increase in postage rates and the increase in the volume of mail on the Utilities' forecast cannot be ignored. The AG has provided no evidence supporting its proposed adjustments to the Utilities' forecasts.

(iv) Legal (NS)

North Shore's Position

The Companies state that the North Shore legal budget was developed through consultation of the business team and the legal department, based not only on historical legal expenses but also expected future requirements and demands for services.

The Companies contend that the AG's proposed adjustment should not be adopted. The AG proposes to adjust the forecasted legal expenses cross-charged to North Shore, essentially on the grounds that this cost has been flat and that the Companies did not provide sufficient data to support the forecast, and Staff agrees. The Companies state that places no weight on how the forecast of this item was developed and that the North Shore figure should be approved.

Staff's Position

Staff finds that the Commission should adopt Mr. Effron's proposed adjustment to legal expenses. AG witness Effron proposes to reduce projected legal expenses for North Shore. Staff states that Mr. Effron cites not only to historical trends, but also to the lack of a defined rationale for the projected increase.

AG's Position

AG witness Effron proposed an adjustment to the legal expense charged by IBS to North Shore. Mr. Effron explained that NS test-year operation and maintenance expenses include $618,000 of legal expense allocated from IBS. This represents an increase of 61% over the actual legal expense of $383,000 in 2013. In response to Data Request NS AG 1.55, NS explained that the increase is based on the assumption that outside legal fees will increase because they have remained flat since 2008. Mr. Effron noted that this is hardly a justification for the steep increase NS projected. The AG asserts that if anything, the alleged rationale seems like more of an explanation of why there should be a forecast of no increase in legal fees.

The AG explains that in order to reflect actual data, and in light of the absence of any valid explanation for the assumed increase, AG witness Effron recommended that test-year legal expenses reflect the average actual legal fees for the years 2012 and 2013 which approximates the five-year average for the years 2009 through 2013. The average actual legal expense for 2012 and 2013 was $446,000. The AG notes that this is $172,000 less than the 2015 test-year legal expense forecasted by NS.

The AG notes that NS/PGL witness Kupsh disagreed with the proposed adjustment. She argued that the legal services budgets are based on consultation between the business team and the legal department, and that the 2015 budget is based upon assumptions regarding the expected demands and requirements of North Shore for legal services, as well as reasonable forecasts of the costs of those services. Again, however, no actual data or computations were discussed or revealed to justify a 61% increase in this expense item. As Mr. Effron noted, the Companies' explanation is no more than a description of the process that is used to forecast legal expenses. The AG finds that Mr. Effron's proposal to use an average of actual legal expense for 2012 and 2013 should be adopted by the Commission.

Commission Analysis and Conclusion

The Commission agrees with the AG and Staff and finds that the Utilities have not provided sufficient evidence justifying their forecasted legal expenses cross-charged to North Shore. The Utilities argued that the IBS legal expense allocated to North Shore was developed based on historical legal expenses and expected future requirements and demands for services but provided no explanation of what the expected future requirements and demands for services represent or why they result in the forecasted escalation in expense. The Commission adopts the AG's proposed adjustment to the legal expense charged by IBS to North Shore.

(v) Integrys Customer Experience ("ICE") Project

(a) Return on Assets and Depreciation

Companies' Position

The Companies explain that the ICE project is scheduled to go into service fully in 2015. This project will unify the Companies' customer information systems with those of other Integrys companies, providing significant benefits to customers, including, among other things, improved efficiency, productivity, and standardization of internal delivery, and improved and enhanced billing, collections, call center and service related offerings. The Companies state that they provided evidence supporting the portions of the forecasted ICE project costs allocated to the Companies. The Companies note that in direct testimony, Companies' witness Ms. Gregor described the Companies' established budgeting and forecasting processes, and overviewed the careful steps through which the 2015 forecasts were prepared, starting from the foundations of the approved 2014 budget prepared in the Fall of 2013. The Companies further claimed that these processes resulted in the forecasted 2015 financial statements that an independent Certified Public Accountant, Deloitte & Touche LLP, confirmed were prepared in accordance with the applicable accounting rules (in accordance with 83 Ill. Adm. Code § 285.7010). The Companies offer that Ms. Gregor also discussed all significant variances in operating expenses from 2012 to forecasted 2015, noting, among other things, that the second largest factor in the increase in the category of Customer Accounts expense was the combination of increased call center costs and costs of the ICE project.

The Companies add that in direct testimony, Companies' witness Ms. Kupsh discussed the IBS budgeting and forecasting process, which parallels those of the Companies, and variances in the IBS costs cross-charged to the Companies from 2012 to forecasted 2015, noting that the third largest factor was the ICE project.

The Companies submit that AG witness Mr. Effron proposes to reduce the portion of forecasted 2015 ICE project depreciation and capital investment costs cross-charged to the Companies using simple math, extrapolating from costs from certain months at the beginning of 2014 and then multiplying by them to reach an annualized figure which he uses to estimate 2015 costs. However, the Companies state that his proposal (1) arbitrarily ignores the forecasted expenditures and plant in service activity, (2) ignores the fact that IBS only bills the Companies for assets that are in service, and (3) while work on the project began in 2012, only a small portion of the ICE project was in service in the months of 2014 on which his proposal is based, making the data from which Mr. Effron extrapolates completely unrepresentative of 2015 costs.

Staff also rejects Mr. Effron's proposed adjustments, noting the expected in service date of the full ICE project and the lack of factual support for Mr. Effron's proposal. The Companies assert that at the evidentiary hearing the AG cross-examined Staff witness Ms. Hathhorn about the fact that the Companies' 2015 forecasts do not reflect any cost savings resulting from the ICE project, but the evidence shows that to be correct. Ms. Hathhorn pointed out that the Companies have been expending money on their portions of the ICE project from 2012 to now and will continue spending through 2015, that the project as a whole will go into service in 2015, and that savings are not expected to occur until 2016.

The Companies contend that the AG essentially just wishes away the above facts. The AG points to data from the first four months and the first six months of 2014, without even considering the above facts, including, among others, the fact that only a small portion of the ICE project was in service in those months, meaning that the costs then do not reflect the costs when the project is in service in 2015. The AG notes that Mr. Effron claimed that his looking at the data from the first six months of 2014 somehow implicitly incorporated the above facts. The Companies argue that the first half of 2014 data does not take into account that the costs are charged to the Companies only to the extent the project is in service.

The Companies also note that in Mr. Effron's rebuttal, he added raw speculation to the implied effect that, if the WEC-Integrys transaction proposal is approved, then the ICE project might be cancelled. The Companies hold that issue belongs in ICC Docket No. 14-0496, not here. The Companies argue that Mr. Effron cited no relevant facts to support his speculation, and it does not make sense. The ICE project work already is well along, even though only a small portion of the project is in service. For example, the project is approximately 90% complete with respect to coding and some system tests have started. The project is expected to be in service fully in 2015. The WEC-Integrys transaction, if approved, is expected to close in Summer 2015. The Companies contend that Mr. Effron's conjecture lacks logic and is not a proper basis for a Commission decision.

The Companies note too that, on October 30, 2014, the AG filed a "Motion to Admit New Information", which sought to add to the evidentiary record a copy of the Companies' DR response ("DRR") AG 3.05 from the reorganization case, Docket No. 14-0496. The Companies state that the Motion offered panoply of assertions and innuendo relating to the ICE project costs issue. The Companies note that they filed their objections to the Motion on October 31st, as per the schedule ordered by the ALJs and that the AG filed a reply on November 3rd that contained additional assertions and innuendo. The Motion was granted on November 5th.

The Companies incorporate their objections to the Motion, including their objections under Ill. R. Ev. 401 and 403. In their Reply Brief, the Companies stated that they believe it is not fair or proper to expect them to anticipate and address in briefing what the AG may claim in its Reply Brief based on reorganization case DRR AG 3.05. The Companies further state that the Commission must base its decision on the evidence in the record and in accordance with the applicable law, including due process principles, but the Companies have not had notice and an opportunity to submit evidence responding to what the AG's Reply Brief will claim in relation to that DRR.

The Companies contend that the existing evidentiary record and DRR AG 3.05 itself in context show that whatever the AG may claim based on the DRR, it does not provide any basis for questioning the 2015 forecasted ICE project costs, nor for adopting AG witness Mr. Effron's proposed adjustments. The Companies note that the AG already argued for a scenario in which the ICE project goes ahead as scheduled but costs less than forecasted, and alternatively for a scenario in which the project is cancelled, as previously discussed. The Companies contend that the AG now, in an apparent effort to exhaust all options, appears to plan to argue for a scenario based on older, non-updated information reflected in DRR AG. 3.05.

The Companies assert that at the evidentiary hearing on September 23rd, the AG showed Companies witness Ms. Kupsh AG Cross Ex. 8. AG Cross Ex. 8 consists of: (1) the Companies' data request response to Staff data request DLH 35.01 in the instant rate cases and (2) the Joint Applicants' response to AG data request 2.13 in Docket No. 14-0496. DR DLH 35.01 asks about DRR AG 2.13. The Companies further note that at this time, counsel for the Companies explained that Companies witness Lisa Gast, as to whom cross-examination had been waived, was the affiant for DRR DLH 35.01.

The Companies state that as can be seen in AG Cross Ex. 8, reorganization DRR AG 2.13 related to an exhibit the Joint Applicants filed in the reorganization Docket. That exhibit was offered to meet the requirement of Section 7-204(a)(7) of the PUA that, in brief, the reorganization applicants provide a five year forecast showing the utility's capital requirements. The Companies explain that DR AG 2.13 is focused on a single item (an assumption) in JA Ex. 4.1. Reorganization data request AG 3.05 is a follow-up to data request AG 2.13, and data request AG 3.05 also relates to that same item in JA Ex. 4.1.

The Companies contend that AG Cross Ex. 8 (in DRR DLH 35.01) explains, however, that the information in JA Ex. 4.1 that is referenced in reorganization DRR AG 2.13 was derived from the Companies' 2013 Long Term Financial plans prepared in Spring 2013, and that the assumptions used in those plans were based on budget data from Summer and Fall 2012. Further, the Companies assert that AG Cross Ex. 8 (in DRR DLH 35.01) also explains that, since then, an updated forecast was developed, and that the 2015 test year data used by the Companies in these rate cases reflects the updated forecast, which includes the forecasted costs (and the absence of savings) in 2015.

The Companies emphasize that the AG considered asking that Ms. Gast be called for cross-examination on this subject, but the AG ultimately agreed with the Companies that the AG would move AG Cross Ex. 8 into evidence and not call Ms. Gast as a witness.

The Companies state that the AG's October 30th Motion brought up assertions about possible savings in 2015 due to the ICE project. The Companies' October 31st response explained, among other things, that reorganization case DRR AG 3.05 itself showed a forecast of no savings in 2015. DRR AG 3.05 did refer to costs that would not be incurred in 2015 if the ICE project continued, but the Companies' forecasts reflect that the ICE project is continuing, and thus they include no such avoided costs. More specifically, the attachment to reorganization Docket DRR AG 3.05 (on page 1) is dated September 17, 2012. The attachment (on page 2, *et seq*.) refers to "Hard O&M Benefits" and "Avoided" costs, but it shows no "Hard O&M Benefits" until 2016. The attachment shows "Avoided" Costs beginning in 2013, but "Avoided" costs are not savings; rather, they are costs that IBS has not incurred but which it would incur if it did not implement the ICE project. The Companies note that the AG's November 3rd reply did not make any further assertions about possible savings.

Thus, the Companies state that the AG's Reply Brief presumably is going to argue from reorganization case DRR AG 3.05, which followed up on information that AG Cross Ex. 8 already has explained is based on budget data from Summer and Fall 2012 and thus does not reflect the later information reflected in the Companies' 2015 rate case forecasts. The Companies assert that the rate case data have been provided by the Companies to address the forecasted 2015 test year. Reorganization case DRR AG 3.05 necessarily will be inconsistent, because the two sets of information were prepared at different points in time. The Companies contend that DRR AG 3.05 is no basis for approval of the AG's proposed adjustments to the ICE project costs.

<u>AG's Position</u>

Test-year expenses include depreciation and return on assets ("ROA") related to IBS hardware and software for the ICE project. The AG states that as shown in the response to Staff Data Request DLH 5.07, Attachment 1, the budgeted depreciation and ROA on the ICE project is forecasted to increase from $11,000 in 2012 to $1,378,000 in 2015 for NS and from $56,000 in 2012 to $7,263,000 in 2015 for PGL.

According to the AG, the problem with this forecast is that the depreciation and ROA related to the ICE project are not increasing as forecasted. The Companies provided updates of the actual ROA and depreciation on the ICE project in 2014 through June, and these updates show little change in the rate of expense from the first four months of 2014. Based on the actual experience in the first half of 2014, the annualized ICE ROA and depreciation from IBS to North Shore is $124,000, and the annualized ICE ROA and depreciation expense from IBS to Peoples Gas is $652,000. The AG argues that this compares to forecasted expenses of $1,378,000 to North Shore and $7,263,000 to Peoples Gas for the 2015 test year.

The AG notes that Mr. Effron updated his adjustments based on the actual expenses for the six months ended June 30, 2014. On Schedule DJE NS C-4 attached to his Rebuttal testimony, Mr. Effron calculated a reduction of $1,254,000 to 2015 test-year ICE depreciation/ROA allocated from IBS to NS. On Schedule DJE PGL C-4, Mr. Effron calculated a reduction of $6,611,000 to 2015 test-year ICE depreciation/ROA allocated from IBS to PGL. The AG asserts that the updates based on additional information in 2014 do not result in significantly different annualized levels of expenses for the adjustments proposed in Mr. Effron's direct testimony.

The AG adds that NS/PGL witness Kupsh criticized Mr. Effron's proposed adjustment to forecasted 2015 ROA and Depreciation related to the ICE program, arguing that his calculations are inaccurate and inappropriate. In his Rebuttal testimony, Mr. Effron noted that Ms. Kupsh claims that his calculations are inaccurate, but does not cite any errors or inconsistencies in the calculations. The AG counters that while Ms. Kupsh may disagree with Mr. Effron's proposed adjustments that does not mean that his calculations are erroneous.

The AG continues that Ms. Kupsh further asserted that the proposed adjustments are inaccurate because they ignore forecasted expenditures and plant-in-service activity. The AG states that to the extent expenditures and plant-in-service activity have actually affected the cross charges for ROA and depreciation on the ICE project, such factors are implicitly incorporated into the adjustments Mr. Effron is proposing. The AG maintains that the Companies are forecasting substantial increases in the ROA and depreciation on the ICE project, but so far, based on the actual experience in 2014, there is little evidence that such increases are actually taking place.

Ms. Kupsh claims that the only accurate measures for the ICE ROA and depreciation expenses are the Companies' forecasted 2015 test-year expenses. The AG contends, however, the actual experience does not provide any indication that the actual level of expenses is increasing to anything like the level of expenses forecasted by the Companies. According to the AG, the Companies simply failed to provide evidence that justified the forecasts. The AG states that ICE ROA and depreciation expenses included in test year operation and maintenance expense should be modified, consistent with AG Effron's proposal.

The AG states as well that in the Companies' application for merger proceeding, Docket No. 14-0496 ("Merger docket"), the Joint Applicants, which include both Peoples Gas and North Shore, provided on October 22, 2014 a data request response (DRR AG 3.05) with a Confidential Attachment 1, following the completion of the evidentiary hearings and filing of the Initial Briefs in the instant docket. The AG explains that the Response and Attachment detail how future costs of the ICE project will be incurred and notes the information shown on Attachment 1 to the Response differs significantly from information provided by the Companies in the instant consolidated docket. The AG states that the response to DRR 3.06 in the Merger dock*et al*so confirms that the forecasted ICE expense numbers provided in this rate case are entirely inconsistent with data supplied in the Merger docket. The AG submits that this discovery in the Merger docket contradicts everything the Companies have stated about both the amount of allocated costs and the timeline of when costs and benefits of the ICE project will be incurred. The AG concludes that the Companies have failed in their burden of proving that their 2015 test year forecast of these amounts is reliable and that the Commission should reject the impact of the Companies timeline and require an appropriate balancing of costs and benefits of the ICE project.

Staff's Position

Staff does not support the AG proposed adjustments for the Companies' ROA related to IBS hardware and software and other non-labor expenses for the ICE Project. Staff notes that ICE is a consolidated IBS customer system, scheduled to go in service in 2015 and that Mr. Effron's calculations use annualized 2014 expenses to adjust the 2015 test year. Ms. Hathhorn testified that it does not appear that annualizing the historical costs of this project is appropriate. Staff finds that Mr. Effron's analysis does not account for the fact that the Companies forecast the ICE system to be placed in service in 2015 and placing the asset into service will trigger the larger depreciation and ROA charges from IBS at that time. Staff adds that Mr. Effron also provided no evidence to the contrary that the majority of the non-labor expenses will begin in 2015 as the software goes in service.

Staff mentions that the AG also called into question whether or not the increased ICE costs would be incurred due to the announced acquisition of Integrys by WEC. The AG opines that the ICE project would be a likely target for operational and financial benefits referenced in the announcement of the acquisition. Staff maintains that the rates in the instant proceeding must reflect only test year costs, and anticipated savings outside the test period are not allowed in rates at this time. Staff discussed at the evidentiary hearing the Integrys Board of Directors' approval of the ICE document provided in discovery, confirming the 2015 in service date, and that savings are projected for 15 years. Staff recommends the Commission reject the AG adjustments for the ICE project.

Commission Analysis and Conclusion

The Commission agrees with the Utilities and Staff and finds the record evidence supports their position. The Commission further finds that the AG's proposal does not consider the Utilities' forecasted expenditures and plant in service activity and that IBS only bills the Utilities for assets that are in service. The AG's proposal also fails to consider that while work on the project began in 2012, only a small portion of the ICE project was in service in the months of 2014 on which Mr. Effron's proposal is based. The Commission notes as well that issues and speculation related to Docket No. 14-0496 do not provide reasonable grounds for rejecting the more recent forecasts of ICE project costs.

(b) Non-Labor

Companies' Position

The Companies state that the evidence supports their forecasted 2015 "non-labor" costs cross-charged to the Companies in relation to the ICE project. The Companies disagree with AG witness Mr. Effron's attempt to reduce the Companies' forecasted costs. The Companies point out that Mr. Effron's proposal is based on looking at costs from only the first four or six months of 2014, yet he assumes they are fully representative of the 2015 costs.

The Companies state that Mr. Effron's proposal fails to discuss relevant facts and lacks a factual foundation as did his first two ICE-related adjustments. The Companies add that Staff agrees that the AG's proposal lacks merit.

The Companies also note that AG witness Mr. Effron suggested that the proposed WEC TEG transaction somehow means that there is a chance the ICE project will be cancelled but this is merely a conjecture that lacks any sound basis. The Companies contend that the AG's proposed adjustments should be rejected.

Staff's Position

See preceding section for the discussion of Staff's position on both the ICE Project Return on Assets and Depreciation as well as Non-Labor adjustments.

AG's Position

The AG states that in addition to the ROA/Depreciation-related expenses, Mr. Effron also proposed to adjust the forecasted 2015 test-year non-labor ICE expenses. Once again, based on the information provided by the Companies, the forecasted increases in the ICE Non-Labor expenses are not taking place at the forecasted rates. Updates of the actual expenses in 2014 through June mirror the activity documented during the first four months of 2014. The AG asserts that based on the actual experience in the first half of 2014, the annualized non-labor ICE expenses from IBS to North Shore is $252,000, and the annualized non-labor ICE expenses from IBS to Peoples Gas is $1,352,000. This compares to forecasted expenses of $1,504,000 to North Shore and $9,058,000 to Peoples Gas for the 2015 test year.

The AG maintains that Mr. Effron's updated adjustment calculated a reduction of $1,252,000 to 2015 test-year non-labor ICE expenses allocated from IBS to NS based on annualized data from the first six months of 2014. On Schedule DJE NS C-4, attached to his Rebuttal testimony, he calculated a reduction of $1,252,000 to 2015 test-year non-labor ICE expenses allocated from IBS to NS. On Schedule DJE PGL C-4, he calculated a reduction of $7,706,000 to 2015 test-year ICE depreciation/ROA allocated from IBS to PGL. The AG notes that the updates based on additional information in 2014 do not result in significantly different annualized levels of expenses from those presented in Mr. Effron's direct testimony.

The AG adds that NS/PGL witness Ms. Kupsh offered a similar criticism of Mr. Effron's proposed adjustment to forecasted 2015 other non-labor ICE expenses that will be cross-charged from IBS to NS and PGL. She claims his calculations are inaccurate and inappropriate. However, Ms. Kupsh does not cite any errors or inconsistencies in the adjustment calculations, but instead claims that Mr. Effron ignored forecasted operation and maintenance expenses for ICE. The AG states that Mr. Effron did not ignore the forecasts of operation and maintenance expenses for ICE. Rather, the actual data supplied by the Companies shows that other non-labor ICE expenses are not increasing as forecasted. The AG asserts that the Companies are forecasting substantial increases in the non-labor ICE expenses, but there is little evidence that such increases are actually taking place. As with the ROA and depreciation on the ICE project, this actual data should not be ignored.

The AG mentions that Ms. Kupsh claims that the only accurate measures for the non-labor ICE expenses are the Companies' forecasted 2015 test year expenses. However, the actual experience does not provide any indication that the actual level of expenses is increasing to anything like the level of expenses forecasted by the Companies. The AG submits that other reasons exist that justify a modification of the Non-Labor ICE expense forecast such as the announcement of the acquisition of Integrys by WEC. That announcement made reference to "operational and financial benefits" that are clear, achievable and compelling and states that the transaction will be accretive to Wisconsin Energy's earnings per share in first full calendar year after closing, with anticipated closing for the merger in the summer of 2015. In his rebuttal testimony, the AG finds that Mr. Derricks did not dispute the potential for "operational and financial benefits" but, rather, cites uncertainties regarding the closing of the transaction.

The AG continues that Mr. Effron testified that while it is not 100% absolutely certain the acquisition of Integrys by Wisconsin Energy Corp. will close exactly as planned, based on experience, he stated that he believes it is more likely than not that the acquisition will take place. Assuming that the acquisition does close, the AG finds that it would seem that the increased costs associated with the ICE project would be a likely target for the "operational and financial benefits" referenced in the announcement of the acquisition, in that the savings could be achieved by simply avoiding increases in expenses rather than having to eliminate expenses that are already being incurred. The AG contends that the increases associated with the ICE ROA/depreciation and other non-labor expenses are by no means certain to the extent that they should be incorporated into 2015 test year operation and maintenance expenses.

The AG concludes that for all of these reasons, the Commission should adopt Mr. Effron's ICE adjustments, which are rooted in data that reflects actual annualized experience for the 2014 period. The Companies simply have not provided credible evidence that the significant jump in ICE expenses forecasted for the 2015 test year are likely to occur – particularly in the midst of a likely corporate acquisition.

Commission Analysis and Conclusion

The Commission finds that the record evidence supports the views of the Utilities and Staff. The Commission also finds that the AG's proposal lacks factual support. The AG's proposal is based on costs from only the first four or six months of 2014 but states that it is fully representative of the 2015 costs. The Commission disagrees. Further, issues and speculation related to Docket No. 14-0496 do not provide reasonable grounds for rejecting the more recent forecasts of ICE project costs.

b. Advertising Expenses

Companies' Position

The Companies note that in rebuttal, they accepted a total of $25,000 of Staff's proposed downward adjustment to advertising expenses for North Shore Gas and Peoples Gas, but rejected Staff's proposed adjustments removing $4,000 of expenses for North Shore and $51,000 of expenses for Peoples Gas because those remaining challenged expenditures were recoverable under Section 9-225 and were also recoverable as charitable expenditures under Section 9-227. The Companies add that although CCI did not submit evidence on this issue, it supports Staff's position.

The Companies hold that Staff's (and CCI's) primary contention is that these expenditures proposed for removal are "of a promotional, goodwill or institutional nature" under Section 9-225 of the Act and, therefore, not recoverable. The basis for Staff's and CCI's argument that these "advertising expenditures" are not properly recoverable is that the Companies classified them, for accounting purposes, under the Companies' Account 909 – Informational and Institutional Advertising. As those "advertising expenditures" are classified in Account 909, Staff and CCI derive the notion that these expenditures are simply used to put the Companies' name in a philanthropic light.

The Companies explain that Section 9-227 of the Act provides for recovery as an operating expense of donations "for the public welfare or for charitable, scientific, religious, or educational purposes, provided that such donations are reasonable in amount." Section 9-225 of the Act addresses advertising expenditures and identifies several categories that "shall be considered operating expenses for gas or electric Companies." 220 ILCS 5/9-225(3). The Companies assert that the expenditures that Staff seeks to disallow support the sponsorship of charitable events including: the Chicago Children's Choir, the Chicago Public Library Foundation, the Children First Fund, Friends of Holstein Park, the Hispanic Heritage Organization, the Museum of Science and Industry, Red Moon Theater, Children of Purpose, Preservation Foundation of Lake County, the University Center of Lake County, and the Waukegan Public Library and other similar events. The Companies contend that the funding of those charitable events supports a range of cultural and educational activities for charitable organizations within Chicago and Cook and Lake Counties. Further, the Companies note that for most of the sponsorships of those charitable events, the Companies use their presence at the events to provide information about the Companies' energy efficiency and energy assistance programs. As a result, the Companies contend that "promotion" of utility energy efficiency and energy assistance programs is not "promotional advertising" for which recovery is prohibited, but is a form of permissible and recoverable advertising under Section 9-225(3)(a), (e) and (i) of the Act, 220 ILCS 5/9-225(3)(a), (e) and (i). Further, the Companies submit that support of charitable events is recoverable under Section 9-227 of the Act, 220 ILCS 5/9-227. Thus, the Companies assert, the expenditures that Staff's testimony proposed to disallow, other than the amounts accepted by the Companies' rebuttal and surrebuttal, are expenditures that are recoverable under Sections 9-225 and 9-227.

The Companies contend that contrary to Staff's assertions, the Companies' "advertising expenditures" are not of a promotional, goodwill or institutional nature, but instead are recoverable expenses that are charitable in nature under Section 9-227 of the Act (220 ILCS 5/9-227) or are recoverable as expenditures supporting the promotion of the Companies' energy efficiency and energy assistance programs under Section 9-225 of the Act (220 ILCS 5/9-225). The Companies presented detailed descriptions of the "advertising expenditures" demonstrating the charitable purpose and nature of the expenditure.

Further, the Companies assert that Staff's contention that these expenditures should not be recoverable lacks merit, as Staff's theory that Section 9-225 requires or warrants disallowance of costs that put the Companies "in a philanthropic light" is not supported by the language or past interpretations of Section 9-225. The Companies contend that such a theory essentially would read Section 9-225 to mean that if the Companies spend money on a good purpose that benefits customers or communities, unless the Companies do it anonymously, then the costs should be unrecoverable. As a result, the Companies argue, the Staff theory is both unreasonable and counter-productive. The Companies also contend that the Staff theory reads Section 9-225 in a manner that is inconsistent with the express allowance of charitable contributions costs recovery under Section 9-227 of the Act, 220 ILCS 5/9-227. The Companies note that the Commission previously rejected the Staff's argument that an expenditure for a charitable purpose under Section 9-227 that puts the Companies' name in a "philanthropic light" should not be recoverable. Docket Nos. 12-0511/12-0512 (Consol.), Order at 164. The Companies assert that the Commission rightly determined that the nature of the expenditure is the determinative factor for rate recovery. *Id.* Further, the Companies argue that the particular accounting entry of these expenditures under Account 909 - Informational and Institutional Advertising also is not determinative of recovery. The Commission ruled in Docket Nos. 12-0511/12-0512 (Consol.) that:

> …the Commission believes the nature of the expense is more important and declines to adopt Staff's position that these expenses can not be considered as charitable contributions because the Companies initially recorded them as advertising expenses.

Docket Nos. 12-0511/12-0512 (Consol.), Order at 164.

The Companies also maintain that, in following the Commission's direction in Docket Nos. 12-0511/12-0512 (Consol.), the Companies significantly changed their processes for distinguishing expenditures that were charitable in nature from other expenditures. The Commission in Docket Nos. 12-0511/12-0512 (Consol.) said that the Commission:

> …believes the Companies must be more careful in distinguishing sponsorship and institutional expenditures that are allowable for charitable purposes and those that are allowable advertising expenses.

Docket Nos. 12-0511/12-0512 (Consol.), Order at 164.

The Companies note that Staff argues that the Companies were not "more careful" in distinguishing the nature of expenditures, contrary to the direction of the Commission in Docket Nos. 12-0511/12-0512 (Consol.). However, the Companies state that they greatly expanded the process for screening and categorization of charitable, sponsorship and institutional expenditures and developed more detail descriptions of the informational and institutional "advertising expenditures" made under Account 909.

The Companies indicate the following changes to their process to distinguish these "advertising expenditures." The Companies have created a more detailed review process for requests for the Companies' participation in a charitable, sponsorship or institutional event, to better insure that such expenditure is for a rate-recoverable purpose. The Companies explain that they first determine if a particular request goes to a rate recoverable-purpose such as an educational, safety, environmental, charitable, human and health services, or community development. If the Companies determine that: (1) such expenditure would fulfill a strategic purpose, whether for the charitable institution, the community and/or customers, (2) such expenditure will further build the Companies' relationship with that charity, the community, and/or customers, (3) the requestor has a strong reputation, including the strength of its management and board, (4) there is a need for a contribution/spending, and (5) such expenditure will be impactful in achieving the charity's, community's, or customers' needs, then the expenditure has met the necessary screening criteria for potential funding. The Companies also review the funding request to determine: (1) if there are multiple funding sources; (2) does the Companies' participation enhance the possibility of other entities funding the educational, safety, environmental, charitable, human and health services, or community development need; (3) is the funding request realistic for the goal; and (4) what is the Companies', its employees', and their retirees' involvement with the requestor and goal.

The Companies state that, once the decision has been made to fund the request for sponsorship and spending, the expenditures are classified into one of two categories: (a) sponsorships or expenditures where information and education related to safety, energy efficiency, energy assistance, and/or billing and payment options are communicated to customers and the community; and (b) sponsorships or expenditures where community services are enhanced and benefited for charitable purpose. Last, the Companies provide expanded descriptions of the expenditure/charitable funding, the organization that is being supported, the nature of the expenditure and cause or program being promoted or advanced. The Companies explain that these changes are a direct result of Docket Nos. 12-0511/12-0512 (Consol.) and serve to distinguish recoverable, charitable expenditures from non-recoverable expenditures under Account 909.

The Companies state that they expect additional guidance for the classification of expenditures related to charitable spending pending the outcome of the ongoing rulemaking concerning the rate case treatment of charitable contributions in Docket No. 12-0457.

The Companies note that Staff argues that the expenditures should not be recoverable as Staff and the other parties would not have the opportunity to adequately and timely review the expenditures for compliance with Section 9-227. The Companies strongly assert that this contention is nonsense, and that Staff has had no issue contending that the "advertising expenditures" should not be recoverable. The Companies state that the "advertising expenditures" that Staff seeks to disallow were brought to the attention of all of the parties in the Companies' direct testimony. Further, the Companies assert that full and expanded descriptions of the expenditures were provided in discovery and included in the Companies' rebuttal exhibits. The Companies contend that they have identified the recoverable nature of the "advertising expenses" early in this docket and have modified and highlighted their processes and procedures as to those expenditures in response to Docket Nos. 12-0511/12-0512 (Consol.). The Companies submit that Staff's proposed adjustments should be rejected as they lack any sound factual basis, are contrary to the evidence, and are contrary to Sections 9-225 and 9-227.

Staff's Position

Staff maintains that the Commission should adopt Staff's rebuttal adjustment to eliminate advertising expenses that are of a promotional, goodwill or institutional nature. Staff's adjustment includes promotional or goodwill natured costs for support of events; expenditures for employee apparel and event "premiums", *e.g.*, pens, pencils, mini-flashlights and travel mugs; and expenditures to provide funding of events for charitable organizations.

Staff explains that the issue of advertising expenses that are of a promotional, goodwill or institutional nature are addressed in Section 9-225 of the Act which expressly states in part:

> In any general rate increase requested by any gas or electric utility company under the provisions of this Act, the Commission shall not consider, for the purpose of determining any rate, charge or classification of costs, any direct or indirect expenditures for promotional, political, institutional or goodwill advertising, unless the Commission finds the advertising to be in the best interest of the Consumer or authorized as provided pursuant to subsection 3 of this Section. 220 ILCS 5/9-225(2).

Section 9-225 of the Act defines goodwill or institutional advertising as:

> [A]ny advertising either on a local or national basis designed primarily to bring the utility's name before the general public in such a way as to improve the image of the utility or to promote controversial issues for the utility or the industry. 220 ILCS 5/9-225(1)(d).

Staff notes that the Commission adopted identical Staff adjustments to eliminate advertising expenses that were of a promotional, goodwill or institutional nature in the Companies' 2007, 2009 and 2011 rate cases. Docket Nos. 07-0241/07-0242 (Consol.), Order at 41; Docket Nos. 09-0166/09-0167 (Consol.), Order at 81; and Docket Nos. 11-0280/11-0281 (Consol.), Order at 47. In the Companies' 2012 rate case, Staff made an identical proposal, but the Commission did not adopt a portion of Staff's proposed adjustment that the Commission determined to qualify as charitable contributions. Docket Nos. 12-0511/12-0512 (Consol.), Order at 164.

Staff holds that the Commission should not allow the Companies to include advertising that is of a charitable nature in rates in this proceeding. In the Companies' 2012 rate case, the Commission stated the Companies must be more careful in distinguishing sponsorship and institutional expenditures that are allowable for charitable purposes and those that are allowable advertising expenses. Docket Nos. 12-0511/12-0512 (Consol.), Order at 164. In spite of the Commission's direction, the Companies have continued to record expenditures that are of a promotional, goodwill or institutional nature that might be allowable for charitable purposes as advertising expenses. If the Companies request recovery of charitable costs as advertising expenditures under the guidelines provided by Section 9-225 of the Act, the Companies should not be permitted to reclassify expenditures during the proceeding to ask for recovery under Section 9-227 of the Act as Staff (and other parties) would not have the opportunity to adequately and timely review the expenditures for compliance with Section 9-227. Staff argues that the Commission should disallow for recovery through rates determined in these proceedings the sponsorship expenditures that have been recorded as advertising that do not meet the requirements under Section 9-225 of the Act.

Further, Staff finds that allowing the Companies to file a rate case with charitable costs for Staff to review as advertising expenses, and then allowing charitable costs to be included in rates as advertising, would give no meaning to the prohibition of promotional, goodwill, and/or institutional advertising required of the Commission by Section 9-225 of the Act.

CCI's Position

CCI notes that Staff witness Mr. Kahle identified claimed advertising expenses that are of a promotional, goodwill or institutional nature and should be disallowed. Mr. Kahle identified two categories of advertising expenses for which recovery is not appropriate: i) Account 909 – costs for support of events; and ii) Account 909 – sponsorships of community events. The Companies accepted a portion of Mr. Kahle's adjustment, but did not accept the portion related to event sponsorships. CCI supports Staff's recommended disallowance.

CCI notes that the Companies claimed that their sponsorships promote awareness about special events and projects that serve the customers in communities in the Companies' service territories and should be recoverable. As Mr. Kahle noted, however, last year the Commission warned the Companies to be more careful in distinguishing sponsorship and institutional expenditures that are allowable for charitable purposes and those that are allowable advertising expenses. Docket Nos. 12-0511/12-0512 (Consol.), Order at 164. CCI explains that this is an important distinction, as Section 9-225 of the Public utilities Act expressly prohibits recovery of advertising expenses incurred for promotional, political, institutional or goodwill advertising. The legislature defined such goodwill or institutional advertising as "advertising… designed primarily to bring the utility's name before the general public in such a way as to improve the image of the utility or promote controversial issues for the utility or the industry." 220 ILCS 5/9-225(1)(d), 5/9-225(2). CCI states that the expenses at issue are not properly recovered as advertising expenses because their primary purpose is to improve the Companies' images. CCI believes that the Commission should adopt Mr. Kahle's adjustment to exclude Goodwill and Institutional Advertising from recovery.

Commission Analysis and Conclusion

The Commission agrees with the Utilities and approves the Utilities' Advertising Expenses of $4,000 for North Shore and $51,000 for Peoples Gas. Staff and CCI seek to disallow the Utilities' "advertising expenditures" that go to charitable purpose: (1) in the case of North Shore Gas: the American Legion, Children of Purpose and the University Center of Lake County and (2) in the case of Peoples Gas: the Museum of Science and Industry, the Red Moon Theater, the Hispanic Heritage Organization and others. The Commission finds that the Utilities have established that these expenditures and the organizations are charitable in nature and therefore recoverable under Section 9-227. Further, the Commission finds that the Utilities have responded to the Commission's directions in Docket Nos. 12-0511/12-0512 (Consol.) and that the Utilities have taken the necessary steps to better classify and distinguish these types of charitable expenditures from nonrecoverable "advertising expenses." The Commission notes that the rulemaking on charitable expenditures in Docket No. 12-0457 should provide further guidance in the classification and distinguishing of expenditures.

c. Institutional Events

Companies' Position

The Companies note that Staff proposes to disallow $203,000 of Peoples Gas' sponsorship of institutional events and $10,000 of North Shore's sponsorship of institutional events, on the theory that the costs are for promotional, goodwill advertising, and thus are barred from recovery under Section 9-225 of the Act. The Companies add that although CCI did not submit evidence on this issue, it supports Staff's position.

The Companies contend that they have demonstrated that their expenditures for institutional events: (1) support local charities, (2) serve as a means for the charities to raise contributions, (3) allow for dialogue between the charities and the Companies so they can better serve the community, and (4) foster cross-collaboration between the Companies and the community so the Companies can better serve their customers. The Companies argue that charitable expenditures are recoverable under Section 9-227.

The Companies claim that, contrary to Staff's argument that these institutional expenditures are recorded as institutional events and are therefore, promotional in nature and not recoverable, these institutional event expenditures support the charitable organizations' public missions and are recoverable. The Companies indicate that these expenditures support institutional events of the Chicago Police Memorial Foundation, the Adler Planetarium, the Chicago Children's Choir, the Chicago Public Library Foundation, Connections for Abused Women and their Children, Chicago Sinfonietta, the Chicago Urban League and along with other charitable institutions' events.

The Companies explain that each of the institutional events where recovery is sought has a description of the nature of the event, the charitable institution holding the event, and a description of the purpose of the expenditures. Further, the Companies assert that the same screening criteria as discussed with regards to Advertising Expenses are used to assess making the expenditure. The Companies contend that Staff makes a blanket dismissal of the expenditures labeled "institutional events", indicating they are simply promoting goodwill, where in reality, supporting these institutional events help support those charitable organizations' public missions. The Companies contend that the claim that the Companies have not shown the sponsorships are not promotional is incorrect, and, moreover, for the claim to be correct, the meaning of the term promotional would have to be stretched beyond the language and the reasonable and fair interpretation of Section 9-225.

The Companies add that Staff and CCI argue that these expenditures should not be recoverable because they put the Companies' names in a "philanthropic light" or improve the image of the Companies. The Companies agree that if the institutional expenditures were solely for promotional or goodwill advertising within Section 9-225(2), then the expenditures should not be recovered. However, the Companies note, the Commission previously has rejected the "philanthropic light" argument, which seeks to redefine funds spent on charitable purposes.

Further, the Companies contend that Staff's claim as to "misclassification" of these institutional expenditures as a means of disallowing the costs should be rejected. The Companies assert that, similar to the contested Advertising Expenses, the nature of the expenditure should determine its recoverability, not the accounting classification. The Companies explain that these institutional events: 1) support local charities; (2) serve as a means for the charities to raise contributions; (3) allow for dialogue between the charities and the Companies so they can better serve the community; and, (4) foster cross-collaboration between the Companies and the community so that the Companies can better serve their customers. The Companies emphasize that this same set of issues regarding institutional expenditures was addressed in Docket Nos. 12-0511/12-0512 (Consol.) and the Commission rejected similar Staff challenges, ruling that:

> The Companies have provided sufficient evidence to show that these contributions were made to support fundraising events for local charities and communities in the Companies' service territory and not primarily to promote the Companies or foster goodwill towards the Companies.

Docket Nos. 12-0511/12-0512 (Consol.), Order at 169.

The Companies argue that an institutional event expenditure that goes to a charitable purpose, such as fundraising for a charitable institution or community group is recoverable. The Companies add that merely because an expenditure is classified as spending for an institutional event does not lead to its disallowance. Docket Nos. 12-0511/12-0512 (Consol.), Order at 169. The Companies assert that the actual nature of the expenditure, in this case as presented by the Companies for support of charitable institutions and community groups within each Utility service territory, determines the recoverability.

To support the Companies position, the Companies note that, similar to changes in descriptions and processes as to "advertising expenditures" under Account 909, the Companies have: (1) expanded the descriptions of the nature of the institutional event,

(2) specifically identified the charitable institution holding the event and (3) have provided expanded descriptions of the purpose of the institutional event spending.

The Companies maintain that as in *Peoples Gas 2012*, the Companies have made the necessary showings, and Staff's adjustments should be rejected. The evidence shows that the costs in question are recoverable.

Staff's Position

Staff states that the Commission should not allow the Companies to recover, through rates set in this proceeding, miscellaneous general expenses for "institutional events annual fund-raising support" because the costs are either of a promotional, goodwill or institutional nature, not necessary to provide utility service to ratepayers, and are therefore barred for cost recovery under Section 9-225 of the PUA. Support of fund-raising events, while promoting good corporate citizenship, are of a promotional and goodwill nature which presents the Companies' names before the general public in a way as to improve their image. Staff maintains that these expenditures are not necessary to provide utility service and provide no direct benefit to ratepayers. The Act requires costs "designed primarily to bring the utility's name before the general public in such a way to improve the image of the utility or to promote controversial issues for the utility or the industry" to be excluded from rates. 220 ILCS 5/9-225(1)(d) and 9-225(2).

In the Companies' most recent rate cases (Docket Nos. 12-0511/12-0512 (Consol.)), Staff made an identical proposal which the Commission adopted, except for a portion that the Commission determined to qualify as charitable contributions. Staff submits that in this proceeding, however, the Commission should adopt Staff's entire adjustment for the same reasons discussed above in section C.3.b for Advertising Expenses. Staff emphasizes that expenditures which are of a promotional, goodwill or institutional nature, which are recorded as miscellaneous general expenses, should not be considered for the purpose of determining rates pursuant to Section 9-225 of the Act.

Staff continues that allowing the Companies to file a rate case with expenditures which are of a promotional, goodwill or institutional nature for Staff to review as institutional events, and then allowing promotional, goodwill or institutional costs to be included in rates as institutional events, would give no meaning to the prohibition of promotional, goodwill, and/or institutional advertising required of the Commission by Section 9-225 of the Act.

CCI's Position

CCI finds that the Commission should adopt Staff witness Mr. Kahle's adjustment to reduce the Companies' proposed test year expenses to exclude expenses incurred for institutional events that are of a promotional, goodwill or institutional nature. The expenses at issue are for tickets or tables at meals where the Companies received promotional recognition. The Companies weakly defended these expenses as being charitable in nature, but did not contest that they received public recognition, as well as tangible benefits such as food and entertainment, for their support. The Companies' intentions to support the organizations described in Mr. Moy's testimony are laudable, and the Companies can continue to give that support, even without ratepayer recovery. However, CCI asserts the benefits the Companies receive from these contributions cannot be ignored, and ratepayer recovery is not permitted for costs designed primarily to bring the utility's name in a philanthropic light or to improve the image of the utility. 220 ILCS 5/9-225(d). CCI holds that these challenged costs are not necessary for the provision of safe and adequate utility service, and they should be excluded from rates. CCI states that accepting the Companies' statements of their belief in the importance of supporting these institutions, their shareholders should be happy to fund the costs of participating in these events without recovery of such expenses in rates. CCI concludes that to protect ratepayers and to comply with the governing statutory constraints, the Commission should adopt Mr. Kahle's adjustment.

Commission Analysis and Conclusion

The Commission agrees with the Utilities and approves the Utilities' Institutional Events expenditures of $203,000 for Peoples Gas and $10,000 for North Shore. The Commission rejects Staff's proposed disallowance of $203,000 of Peoples Gas' institutional event spending and $10,000 of North Shore's institutional event spending and finds that those institutional event expenditures made by the Utilities are recoverable. The Utilities have presented sufficient evidence identifying those institutional events' spending as contributions made to support local charities and community groups and not primarily to promote the Utilities and enhance its goodwill in the community. The Commission concludes these institutional event expenditures are not barred under Section 9-225 and are recoverable under Section 9-225 and 9-227.

d. Charitable Contributions

Companies' Position

The Companies note that Staff proposes to disallow $28,000 of Peoples Gas' charitable contributions and $1,000 of North Shore's charitable contributions. The Companies state that Staff proposes to disallow those charitable contributions as those contributions are either to: (1) organizations outside of the Companies' service territory or (2) universities and colleges outside of the State of Illinois. The Companies add that Staff indicates that, for a charitable expenditure to be recovered by a utility in accordance with Section 9-227, the expenditures must be directed to charitable organizations within a utility service territory or providing some type of education benefit within a utility service territory. The Companies mention that, in support of their argument, Staff and CCI cite the Commission's decision in Docket Nos. 12-0511/12-0512 (Consol.) that held that a utility must show a charitable donation benefit customers in its service territory in order to recover those expenses. Docket Nos. 12-0511/12-0512 (Consol.), Order at 167. The Companies state that although CCI did not submit evidence on this issue, it supports Staff's position.

The Companies explain that Section 9-227 of the Act, 220 ILCS 5/9-227, expressly allows recovery of donations made by a public utility for "…the public welfare or for charitable scientific, religious, or education purposes…" as the amounts are reasonable. The Companies note that the overall reasonableness of the amounts of the charitable contributions is uncontested. Further, Section 9-227 limits the power of the Commission to establish rules disallowing charitable contributions, stating in part:

> In determining the reasonableness of such donations, the Commission may not establish, by rule, a presumption that any particular portion of an otherwise reasonable amount may not be considered as an operating expense. The Commission shall be prohibited from disallowing by rule, as an operating expense, any portion of a reasonable donation for public welfare or charitable purposes.

Nonetheless, the Companies assert that Staff seeks to maintain the requirement (in substance, a rule) disallowing charitable contributions outside a utility's service territory. The Companies state that in Docket Nos. 12-0511/12-0512 (Consol.), the Commission ruled that:

> The Commission notes that a utility is not precluded from recovering expenses for charitable contributions simply because the organization receiving the donation is outside the utility's service territory. However, the utility must show that the donation will provide a benefit to customers in its service territory to recover these expenses.

Docket Nos. 12-0511/12-0512 (Consol.), Order at 167.

Further, the Companies detail that the Commission also ruled in Docket Nos. 12-0511/12-0512 (Consol.) that charitable expenditures to colleges and universities outside of the State of Illinois were not recoverable. Docket Nos. 12-0511/12-0512 (Consol.), Order at 167. The Companies disagree with the Commission's ruling in Docket Nos. 12-0511/12-0512 (Consol.), noting that Section 9-227 does not include such a restriction. The Companies respectfully request that the Commission reconsider its approach to these contributions in light of the statutory requirements applicable to recovery of charitable contributions as an operating expense. Statutorily, restrictions on the recoverability of charitable contributions under Section 9-227 are based on: (1) the recipient of the charitable contribution - entities that provide contributions to public welfare, or scientific, religious or educational purpose and (2) whether the donations are a reasonable amount. The Companies argue that the contributions at issue meet these criteria.

The Companies state that many of the out-of-service territory contributions that are challenged by Staff are related to utility employee matching gifts where the Companies, match, dollar-for-dollar, up to a certain level gifts to charitable institutions. Many of these contributions are individually small charitable contributions that are in communities where the Companies' employees live or coincide with the educational institution that an employee attended. Further, the Companies assert that strengthening the overall network of charitable institutions in northern Illinois and surrounding areas is beneficial to the Companies' service territory in general. In addition, the Companies contend that out-of-state universities and colleges do provide graduates that work for the Companies.

The Companies add that CCI argues that charitable contributions are discretionary utility spending and not necessary for the provision of safe and reliable utility service. Further, CCI contends that charitable contributions "force" utility customers to support organizations that an individual customer may not otherwise support. The Companies argue that CCI's argument should be disregarded, as CCI's two conditions as to the "necessity" of the expenditure or the "forcing" of customer expenditure are not elements of the statutory requirement for rate recovery of a charitable expenditure and instead amount to an attempt to overrule the statute. The Companies state that the statutory requirement for recoverability of utility charitable expenditures indicated in Section 9-227 is:

> …whether a rate or other charge or classification is sufficient, donations made by a public utility for the public welfare or for charitable scientific, religious or educational purposes, provided that such donations are reasonable in amount.

220 ILCS 5/9-227.

The Companies assert that Staff and CCI ignore that Section 9-227 expressly allows recovery of donations made by a public utility for "…the public welfare or for charitable scientific, religious, or education purposes…" as the amounts are reasonable and the reasonableness of the amounts is uncontested here. The Companies contend that although particular occurrences of employee contributions may vary over time, the overall expected total level of contributions, as indicated in each Utility's C-7 filing is reasonable for the future test year of 2015. The Companies emphasize that Section 9-227 limits the power of the Commission to establish rules disallowing charitable contributions.

The Companies argue that the statutory standard for recovery of expenditures under Section 9-227 is clear, and notes that no party has argued that the particular expenditures do not go to a charitable purpose. Further, the Companies state that no party has argued that the overall amount of charitable expenditures is unreasonable. The Companies contend that Staff's position is contrary to Section 9-227 both in terms of its provisions regarding what is recoverable and in terms of its provisions limiting disallowance by rule. The Companies assert that the charitable organizations where Staff is seeking a disallowance of expenditures are all entities that provide contributions to public welfare, or scientific, religious or educational purpose. The Companies note that these charitable organizations include, for example, food banks and a wide range of educational institutions. The Companies hold that as these organizations contribute to the public welfare, or scientific, religious or educational purpose and the specific level of expenditures are not argued as unreasonable, these expenditures should be recoverable. The Companies argue that the Staff position proposes a ruling that would be unlawful and should be rejected. However, the Companies assert that even if Staff's position could be lawful, the evidence here supports recovery.

<u>Staff's Position</u>

Staff maintains that the Commission should adopt Staff's rebuttal adjustment to reduce test year expenses for charitable contributions for which there is no tangible evidence of benefit to ratepayers in the Companies' service territory. Staff's adjustment eliminates contributions made to organizations outside the Companies' service territory and colleges and universities outside of the State.

Staff notes that in the Companies' most recent rate case, the Commission accepted the portion of Staff's proposed adjustments to disallow contributions made to organizations outside the Companies' service territory and to colleges and universities outside of the State of Illinois. Docket Nos. 12-0511/12-0512 (Consol.), Order at 166-167.

CCI's Position

CCI supports Staff witness Kahle's adjustment to the Companies' contributions to universities outside Illinois and to other organizations outside the Companies' service territories. Contributions for charitable and other statutorily permitted purposes are a discretionary expense not necessary for the provision of safe and reliable service. CCI states that these contributions essentially force all of a utility's ratepayers to support organizations chosen by utility management, even if the goals and objectives of those organizations conflict with those of individual ratepayers.

CCI explains that though Section 9-227 of the PUA allows recovery of reasonable contributions, the Commission has noted that, in order for a contribution to an organization outside of a utility's service territory to be recoverable, the utility must show that the donation will provide a benefit to customers in its service territory. Docket Nos. 12-0511/12-0512 (Consol.), Order at 164. Additionally, the Commission has voiced its concern that, particularly in the current economic climate, "every dollar will make a difference" to ratepayers. Accordingly, the Commission concluded that claimed charitable contributions must be closely examined. *Ameren Illinois Co. d/b/a Ameren Illinois*, Docket No. 11-0282, Order at 31 (January 10, 2012).

CCI finds that while the Companies are free to continue making contributions to any organizations they choose, the Commission should, as it has in the past, limit recovery of those contributions to those that benefit the Companies' ratepayers. CCI submits that Mr. Kahle's adjustment is reasonable and should be adopted by the Commission.

Commission Analysis and Conclusion

The Commission agrees with Staff and CCI and finds that the charitable contributions made by the Utilities related to matching the Utilities' employee gifts to out-of-state universities and colleges are not recoverable. Staff's adjustment eliminates contributions made to organizations outside the Companies' service territory and colleges and universities outside of the State. Staff's adjustment comports with numerous past Commission rulings on the recovery of the Companies' charitable contributions for which there is no tangible evidence of benefit to ratepayers in the Companies' service territory.

e. Social and Service Club Membership Dues

Companies' Position

The Companies note that Staff proposes to disallow $44,000 of Peoples Gas' social and service club membership dues and $17,000 of North Shore's social and service club membership dues. The Companies note that although CCI did not submit evidence on this issue, it supports Staff's position. The Companies state that Staff proposes to disallow those social and service club membership dues by arguing that they are a promotional and goodwill practice and not necessary in providing utility service. The Companies offer that Staff references Peoples Gas' direct coordination with the City of Chicago Aldermanic offices and the City's Department of Water Management in its ongoing AMRP project as a reason the "indirect" contacts and related expenditures for social and service clubs should not be included in the test year. In addition, Staff asserts that certain portions of these dues are lobbying expenses, and therefore not recoverable. The Companies contend that Staff is incorrect that the expenses are not appropriate and support utility service to customers.

The Companies argue that their expenditures on social and service clubs provide benefits to customers in an indirect way by allowing the Companies to work with various external stakeholders within their service territories. The Companies assert that the membership in these social and service clubs allow the Companies to interact with other business and governmental entities to develop contacts, exchange ideas, coordinate current projects and plan future projects. Further, the Companies submit that these memberships provide important interactions with other business and governmental entities within the Companies' service territories. The Companies hold that they provide, maintain and continue to develop vital infrastructure within their service territories.

The Companies note that while the City of Chicago Aldermanic offices and the City's Department of Water Management are key stakeholders where Peoples Gas has direct, routine and beneficial interactions, there are more stakeholders than just those groups. The Companies explain that the social and service club memberships expose the Companies to a wider group of parties with wider interests from across the Companies' service territories, and that social and service club memberships can provide opportunities for broader interactions that allow for better coordination, identification of issues, and can help improve the Companies' service to its customers.

The Companies state that Staff and CCI argue that certain of these social and service club membership expenditures are not necessary for utility service. The Companies disagree with this as a ground for disallowance. The Companies contend that these expenditures for social and service club memberships enhance the ability of the Companies' personnel to interact with stakeholders in the Companies' service territories and help identify challenges, risks, and opportunities to improve the Companies' services to its customers. The Companies further note that Staff argues that certain of these expenditures are unnecessary, as the Companies already have direct contacts with stakeholders in the Companies' service territories. The Companies contend that although they have direct contacts with a variety of stakeholders in the Companies' service territories, the advantage that the social and service club memberships bring is the ability to interact with a wider group of business and governmental entities. The Companies submit that Staff's argument that the Companies' expenditures for social and service clubs memberships provide no customer benefit should be rejected.

<u>Staff's Position</u>

Staff argues that the Commission should adopt Staff's rebuttal adjustments to remove social and service club membership dues which are promotional or goodwill in nature. While these social and service club membership dues may promote good corporate citizenship, they are not necessary in providing utility service. Staff asserts that ratepayers should not be burdened with the expense of the Companies participating in these organizations, and these nonessential expenses should be removed from the Companies' test year operating expenses.

Staff submits that in the Companies' 2007, 2009, 2011 and 2012 rate cases the Commission accepted Staff's proposed adjustments to remove certain social and service club membership dues. Docket Nos. 07-0241/07-0242 (Consol.), Order at 41-42; Docket Nos. 09-0166/09-0167 (Consol.), Order at 41; Docket Nos. 11-0280/11-0281 (Consol.), Order at 46; and Docket Nos. 12-0511/12-0512 (Consol.), Order at 119.

CCI's Position

CCI argues that the Commission should adopt Staff witness Mr. Kahle's adjustment to remove certain social and service club dues that are promotional and goodwill practice in nature. CCI states that participation in these organizations is not necessary for the provision of safe and reliable service.

CCI explains that in the past the Companies have accepted Staff's adjustment to social and service club dues. Docket Nos. 12-0511/12-0512 (Consol.), Order at 119; Docket Nos. 11-0280/11-0281 (Consol.), Order at 46; Docket Nos. 09-0166/09-0167 (Consol.), Order at 41; Docket Nos. 07-0241/07-0242 (Consol.), Order at 42. However, in this case, the Companies continue to seek recovery for these costs, arguing that the networking opportunities and exchange of ideas afforded by participation in social and service clubs facilitates interactions with businesses and municipalities who are affected by the Companies' construction programs.

CCI notes that the Companies assert that all of their social and service club membership dues are recoverable costs. CCI argues that with regard to the provision of regulated services the Companies already provide direct channels of communication with the businesses and municipalities that are members of such organizations. Moreover, according to the Companies, each utility establishes and uses its organization's customer service and planning department. Such organizational mechanisms for interacting with customers and governmental agencies are already in place, and they are paid for by ratepayers.

CCI claims that networking is simply not a recoverable cost of providing service under the PUA, nor should it be. If the Companies continue to find merit in the networking opportunities afforded by participating in these social and service clubs, then their shareholders should bear those costs. CCI submits that the Commission should adopt Mr. Kahle's reasonable adjustment.

Commission Analysis and Conclusion

The Commission agrees with Staff and CCI and adopts Staff's proposed disallowance of social and service club membership dues in the amount of $44,000 for Peoples Gas and $17,000 for North Shore. The Utilities claim that these expenditures provide benefits to customers in an indirect way by allowing the Companies to interact with other business and governmental entities to develop contacts, exchange ideas, coordinate current projects, maintain and continue to develop infrastructure within its service territories. The Commission disagrees and finds that these expenditures are not recoverable.

4. Amortization Period for Rate Case Expenses

Companies' Position

The Companies note that Staff proposes to change the amortization period for rate case expenses from two years to two and one-half years, based on the premise that the Commission, if it approves the proposed WEC-Integrys transaction in Docket No. 14-0496, may approve a condition proposed there by the joint applicants regarding when the Companies' next new rates may go into effect.

The Companies state that Staff's proposal is too speculative to adopt, because it assumes approval in that Docket of both the proposed reorganization and that specific proposed condition, as well as approval of the transaction by the applicable out of state regulatory authorities.

The Companies' contend that their proposal to amortize rate case expenses over two years should be adopted. The two year amortization period is based on what the Companies have experienced in their most recent rate cases. Furthermore, the two year period is the same period approved in the Companies' 2012 rate cases. Docket Nos. 12-0511/12-0512 (Consol.), Order at 170, 175.

Staff's Position

Staff argues that the Commission should take administrative notice of the Companies' filing in Docket No. 14-0496 and amortize rate case costs over a period of two and one-half years. Staff states that in their merger filing the Companies committed that any further requests to change base rates would become effective no earlier than two years after the reorganization transaction closes and that the base rates resulting from the instant proceeding would remain "…unchanged for two and a half years or so after they are approved by the Commission." Staff adds that new rates in the instant proceeding would go into effect on or before February 1, 2015 and that the reorganization transaction will not close until July 2015 at the earliest. According to Staff, a July 2015 closing means that the Companies' next base rates would go into effect no earlier than July 2017, that is, two and a half years from when a Commission order is issued in the instant proceeding.

Staff acknowledges that while the outcome of the merger case is unknown, Staff cannot recall a merger petition which was denied. Staff asserts that the Commission should consider the history of merger approvals and adopt two and one-half years as the minimum period for which base rates resulting from the instant proceeding will be in effect.

CCI's Position

CCI submits that Mr. Kahle's proposal to amortize rate case expense over two and a half years, as opposed to the two years proposed by the Companies, is imminently reasonable given the Companies' own proposal that, after the instant case, new rates will not go into effect any earlier than July 2017. The Companies have made that commitment in the pending reorganization case filed by the Companies (and other joint applicants), should the reorganization be approved. CCI continues that while it cannot be known for certain whether the reorganization will be approved, the Commission must set just and reasonable rates in this proceeding based on the evidence in this record. CCI maintains that evidence suggests that it is possible, if not likely, that new rates will not take affect for at least two and a half years and the Companies have presented no evidence to propose that new rates will be effective any earlier.

CCI adds that with approval of PGL's Rider QIP tariff, the Companies are no longer subject to the substitute natural gas ("SNG") related requirement for biennial filings. 220 ILCS 5/9-220.3(h). In the past, in the absence of a time-specific filing requirement, the Companies have delayed filing a new case for more than a decade (between Docket Nos. 95-0031/95-0032 and Docket Nos. 07-0241/07-0242). CCI states that here the Companies have simply made a bald assertion that a two-year amortization period should be approved. Given the evidence that has been presented on this issue, Mr. Kahle's proposed amortization period is the most reasonable and should be adopted; the short amortization period proposed by the Companies is unsupported, presents a distinct possibility of over-recovery, and should be rejected.

Commission Analysis and Conclusion

The Commission agrees with Staff and CCI and adopts two and a half years as the amortization period for rate case costs. Although a two-year rate case amortization period was just approved in the Utilities' last rate case in 2012, the Commission is reluctant to grant the same two-year period pending the outcome of ICC Docket No. 14-0496. Two and a half years is the earliest the Utilities may file another rate case if their merger request in the aforementioned docket is approved. The Utilities' proposal for a two-year amortization period would allow them to over-recover rate case expense, if the proposed reorganization is approved. Based on the Utilities' stated objectives and proposal, as noted in the merger docket, as well as the likelihood that the merger will occur, the minimum amortization period that is appropriate is two-and-a-half years.

5. Peer Group Analyses

AG's Position

The AG sponsored the peer group analyses of economist Dr. David E. Dismukes, Ph.D., who is the Director of the Center for Energy Studies and a Professor at Louisiana State University. Mr. Dismukes prepared a peer group comparison of the Companies' O&M and A&G costs, relative to that of 17 other Midwestern natural gas local distribution companies ("LDCs") that all have at least 50,000 customers. Mr. Dismukes used historical expense data from each utility company's state regulatory commission filing for each of the ten years 2004 through 2013. The AG explains that the purpose of this peer group comparison is to provide regulators with an objective, empirical measure of a utility's prior and current cost performance relative to other comparable Companies. Mr. Dismukes standardized expense data relative, first, to number of customers, and second, to volume of throughput, is a standard method in peer group analyses of utility cost performance.

The AG submits that Mr. Dismukes found that North Shore's O&M costs per customer in the most recent year, 2013, are estimated to be 13 percent higher than the peer group average and 191 percent higher than the "best performing company" in the sample, where the "best performing company" is defined as the one with the absolute lowest unit cost in each year over the past decade. North Shore's O&M expenses per customer have increased relative to the regional utility average over time. North Shore's A&G costs per customer in the most recent year (2013) are estimated to be 125 percent higher than the peer average and 1,232 percent higher than the "best performing company" in the sample. North Shore's A&G costs per customer experienced significant growth between the 2007-2010 time period, growing at an annual average rate of about 15.2 percent.

The AG notes that switching the focus to costs per volume, North Shore continues to look inefficient. In 2013, North Shore is estimated to have O&M costs that are 15 percent above the regional peer average, and 181 percent higher than the best performing utility included in the peer group. In 2013, North Shore Gas's A&G costs per Mcf were 120 percent higher than the peer average and were orders of magnitude higher than the best-performing company in the peer group. North Shore's trend in A&G cost per Mcf was a significantly higher growth rate than the peer group from 2007-2010.

The AG states that in summary Mr. Dismukes found that North Shore has current A&G costs (normalized either per customer or per volume) that are beyond a reasonable range, which he defined based on his expertise to mean within two standard deviations from the peer group average.

Mr. Dismukes also found that Peoples Gas' O&M costs per customer in 2013 are estimated to be 140 percent higher than the peer average and 520 percent higher than the best performing company in the sample. Peoples Gas consistently shows higher-than-average O&M costs per customer that are also growing at a much faster rate (an average of 9.7% annually since 2008) than any of the other Companies in the regional peer group (3.4% annually since 2008 on average). Peoples Gas' A&G costs per customer in 2013 are estimated to be 155 percent higher than the peer average and 1,407 percent higher than the best performing company in the sample. While Peoples Gas has seen relatively flat to decreasing A&G cost-per-customer trends since 2005, these costs have been and continue to be considerably higher than the regional peer group average.

The AG continues that normalized per volume, Peoples Gas' costs look even worse. Peoples Gas is estimated to have 2013 O&M costs per Mcf that were 164 percent higher than the regional peer average and 543 percent higher than the best-performing regional peer utility for that year. Considering Peoples Gas' trend over time, its O&M cost per volume is clearly growing at a much faster rate than O&M cost per volume in the peer group. In 2013, Peoples Gas's A&G costs per Mcf were 167 percent higher than the peer average and were orders of magnitude higher than the best-performing company in the peer group. PGL's trend in A&G cost per Mcf was relatively flat over time, even while its absolute levels of costs were significantly higher than the peer companies.

The AG states that Mr. Dismukes found that Peoples Gas has current O&M costs (whether normalized per customer or per volume) that are well beyond the "reasonable range" (defined statistically as described above for North Shore) compared to the peer group average. Mr. Dismukes also found that Peoples Gas has current A&G costs (per customer or per volume) that are beyond the “reasonable” statistical boundary.

The AG argues that the only witness from North Shore or Peoples Gas to address Mr. Dismukes’s findings was NS/PGL witness Mr. Dennis M. Derricks. In rebuttal testimony, Mr. Derricks suggested that the 17 other Companies included in Mr. Dismukes’s peer group should not be treated as “peers” (despite that they are also in the Midwest Census Region and serve at least 50,000 customers) because Mr. Dismukes did not show that the other companies have comparable service territories, comparable systems, comparable sizes, and comparable state and local regulations.

Mr. Derricks also pointed to the fact that some of the companies in the peer group are combined gas and electric Companies. In surrebuttal testimony, Mr. Derricks similarly suggested that Mr. Dismukes’s rebuttal analyses do not provide information that the Companies in the alternative ‘peer groups’ have comparable service territories (including having comparable customer bases over time), comparable systems, and comparable state and local regulations. He also argued that none of the Companies in Mr. Dismukes’s rebuttal peer group analysis include only an urban area like Peoples Gas. He added that Mr. Dismukes did not provide information as to the peer Companies’ (1) accounting policies regarding expensing versus capitalization, (2) gas distribution system characteristics, or (3) applicable state and local regulations. Finally, Mr. Derricks argued that Mr. Dismukes has not normalized the delivery data in his cost-per-volumes analyses.

The AG notes that Mr. Derricks did not explain why an all-urban area like PGL’s service territory might necessarily, for that reason, have higher operating expenses. Mr. Derricks did not explain how state and local regulations applicable to Peoples Gas or North Shore might drive up operating expenses relative to the effect of state and local regulations in other jurisdictions. He did not make any attempt to explain how Peoples Gas or North Shore might significantly differ in their accounting policies or gas distribution system characteristics from the other peer companies or how any such differences could drive differences in operating expenses. The AG continues that while anything is certainly possible, Mr. Derricks made no attempt to show how any of the Companies’ immutable characteristics are likely to make them outliers in normalized spending with respect to the peer group.

The AG asserts that to address some of Mr. Derricks’s objections, Mr. Dismukes repeated his analysis with two alternative peer groups: first, a group of nine other LDCs in the Midwest and/or Northeast census regions that serve large metropolitan areas with populations of at least two million; and second, a group of 17 other LDCs in the Midwest and/or Northeast census regions that serve at least 250,000 customers and reported at least 10 percent high priority mains, for at least five years over the past decade. Mr. Dismukes’s analysis with the large metropolitan area peer group did not significantly alter his findings with respect to PGL’s unreasonably high O&M cost position or the historical trends thereof. He did find, though, that PGL’s A&G costs were only 23% higher than the peer average per customer and only 27% higher than the peer average per Mcf, down from 155% and 167% higher in the original analysis.

The AG explains that Mr. Dismukes’s analysis with the high priority mains peer group showed that Peoples Gas’ O&M cost-per-customer performance was competitive with the large utility high priority mains peer group average during the period spanning 2003 to 2006. He found that People's O&M cost performance has deteriorated since 2006, relative to the other large Companies that have high shares of leak-prone pipes. By 2012, PGL's O&M cost performance per customer was 64 percent above the high-priority mains peer average, and 226 percent above the best-performing company in the group. Per Mcf, the Peoples Gas O&M cost performance was initially better than the peer group average until 2007, at which time its O&M costs per Mcf performance began to deteriorate relative to the high-priority-main peer group. Since 2007, Peoples Gas' O&M costs per Mcf rank 14th and 16th out of 18 companies in the group.

The AG states that looking at PGL's A&G costs relative to the high-priority main peer group, Mr. Dismukes found that the Company's A&G costs per customer averaged over 75 percent higher than the peer average for the past decade and around 20 percent higher in 2012. Peoples Gas' 2012 A&G costs per customer were also about 580 percent higher than the best performing company in the sample. Normalized by volume, PGL's A&G cost performance was 21 percent higher than the high-priority sample average and 740 percent higher than the best performing peer utility in the sample. Peoples Gas' A&G cost-per-volume trends over time are comparable to those discussed in Mr. Dismukes's direct testimony analyses.

In conclusion, the AG states that whether looking at his original peer group sample or focusing on peer groups that might arguably, under the most charitable interpretations of PGL's objections, be more appropriately selected for comparison with Peoples Gas, Mr. Dismukes still found that Peoples Gas is a high-cost utility. Mr. Dismukes recommended that, in light of the higher-than-reasonable O&M and A&G expense levels he found to be endemic at North Shore and Peoples Gas, the Commission should accept the O&M and A&G expense recommendations offered by Mr. Effron. Mr. Dismukes argued that his analysis shows that there are likely considerable accumulated inefficiencies embedded in the Companies' test-year projections that need to be eliminated. He further argued that Mr. Effron's proposed reductions to test-year operating expense at both Companies would assist in bringing the Companies' costs more in line with the 'reasonable range' by reducing the discrepancies between the Companies and their peers.

The AG notes that Mr. Derricks observed several times in his testimony that Mr. Dismukes did not propose specific line-item adjustments to the Companies' test-year expenditures. The AG submits that Mr. Dismukes's explanation for the appropriate use of his findings speaks for itself. While the AG presented statistical analysis by Mr. Dismukes showing the inefficiency of NS and PGL, the AG maintains that it also presented compelling personal testimony of PGL customers who experienced firsthand the Company's inefficiency. The AG submits that Mr. Dismukes's findings, together with the wastefully inefficient service experienced by the Peoples Gas' two consumer witnesses, provide further support for the proposed adjustments to operating expenses made by Mr. Effron.

<u>Companies' Position</u>

The Companies state that, ostensibly in support of AG witness Mr. Effron's proposed adjustments to O&M and A&G expenses, AG witness Dr. Dismukes presented what he claimed are “peer” group analysis of the Companies’ O&M and A&G expenses. The Companies note that neither Dr. Dismukes nor Mr. Effron tied the “peer” group analysis to any of Mr. Effron’s specific proposed adjustments. Further, Dr. Dismukes did not himself propose any adjustments. The Companies maintain that his analyses are incomplete and they are not a reliable basis of support for any of Mr. Effron’s O&M and A&G expense adjustments, for numerous reasons.

The Companies submit that when Mr. Effron’s specific adjustments to O&M and A&G expenses are considered, it is clear that they rely on specific points about the Companies, *i.e.*, their test year employee levels, increases in medical benefits expenses, and the challenged IBS cost items. However, Dr. Dismukes’ testimony simply does not address those items in any direct or meaningful way.

The Companies state that the AG acknowledges that Dr. Dismukes did not propose any specific adjustments, but the AG claims that his analyses nonetheless support Mr. Effron’s proposed O&M and A&G expenses adjustments. The AG, like Dr. Dismukes, makes no attempt to explain how the analyses tie to any of those specific adjustments. For example, the AG does not explain how assertions that the Companies’ costs are high compared to their “peers” somehow supports the hypothesis that the Companies will have fewer employees in 2015 than they have forecasted, or that the independent actuary overestimated the increases in medical benefits costs in 2015.

The Companies also mention that Dr. Dismukes’ analyses expressly are limited to O&M and A&G expenses. They do not take into account overall costs of service, because they do not include any of the categories of customer expense or the return of and on plant and other capital investments. The Companies state that he presented no comparison of overall costs of service of the Companies versus other companies.

As well, the Companies find Dr. Dismukes’ analyses look at data from 2004 to 2013, but the test year in the current cases is 2015. Moreover, he never addresses the fact that the Commission reviewed the Companies’ costs of services in their 2007, 2009, 2011, and 2012 rate cases.

The Companies continue that Dr. Dismukes failed to show to any reasonable degree that the “peers” are peers of the Companies for cost comparison purposes in the current cases. He did not show, among other things, that they have comparable service territories (including whether they have comparable customer bases over time), comparable systems (such as the prevalence of inside or outside metering), or comparable state and local regulations under which they operate. Many of the “peers” are combined gas and electric companies (which could result in common cost being reduced), none is an essentially all urban utility like Peoples Gas, and he did not examine the state and local regulations under which the “peers” operate. Regulations matter, as has been discussed with respect to restoration expenses, for example. He also did not show that they have comparable accounting policies such as for when expenses are capitalized or accounting for service company expenses. The Companies state as well that he did not look at whether any of the “peers” had a rate freeze or other rate increase prohibition in place during the period he studied.

The Companies note that the AG attempts to defend the contention that the “peer” companies are in fact peers, however the AG’s arguments fail. Dr. Dismukes should be expected to show that the “peer” Companies are in fact peers, and the AG fails to refute Mr. Derricks’ criticisms. For example, the AG claims that Mr. Derricks did not show that it matters that Peoples Gas has an all urban service territory unlike all of the “peers” nor how state and local regulations might drive up operating expenses. The Companies state that is not correct. As Mr. Derricks pointed out, regulations matter, as has been discussed with respect to the City of Chicago’s regulations and restoration expenses. The Companies note that in the instant cases, the Companies’ direct testimony supported a forecasted $16,780,000 increase as of 2015 in Peoples Gas’ distribution expenses compared to the 2012 level due primarily to changes in Chicago Department of Transportation Regulations that went into effect in the second half of 2012 or 2013, and further changes that became effective in 2014. The Companies maintain that this increase is uncontested. Additionally, in surrebuttal the Companies pointed out that paving costs (which reflect regulatory requirements) are running nearly $8 million over the forecast as of August 2014, an increase that was not reflected in Peoples Gas’ proposed revenue requirement. In the Companies’ 2007 rate cases, the Commission approved (with modifications) updated rebuttal amounts for Peoples Gas’ resurfacing costs in the City of Chicago. Docket Nos. 07-0241/07-0242, Order at 40. Also with respect to whether the peers have similar accounting policies, or gas distribution systems, the AG tries to reverse the burden of proof, by claiming that the Companies have to disprove that the “peers” are comparable to the Companies, rather than Dr. Dismukes having to show they are comparable in the first place.

The Companies submit that a significant part of Dr. Dismukes’ analyses is based on costs per volume of gas delivered, but he did not explain how that is a relevant or meaningful criterion, and he has not normalized that delivery data. The AG’s Initial Brief suggests that looking at costs per volume is a standard method, but the AG does not deny that Dr. Dismukes did not normalize the delivery data. Finally, the Companies contend that Dr. Dismukes did not identify any specific expense of either utility that he claims is imprudent, inefficient, or excessive.

The Companies note that the AG questions Mr. Derrick’s qualifications as a statistician, and notes that he has not published papers or taught courses on peer group analysis, and that the development of the Companies’ operational budgets is not his responsibility area. However, Mr. Derricks has an engineering degree, an MBA, and 23 years of experience working for companies. He is not an academic, so his not publishing papers or teaching courses is not an indictment. The AG does not explain how his not being one of the employees tasked with developing operational budgets undercuts his criticisms, and the AG has been unable to refute those criticisms.

The Companies continue that the AG discusses at great length the individual complaints of two Peoples Gas customers. The treatment of each and every customer matters, but the AG never shows that discussing the circumstances of two customers bears in any meaningful way on the issues in these rate cases. Neither customer has filed a complaint with the Commission.

Commission Analysis and Conclusion

The Commission agrees with the Utilities and finds that the Peer Group analyses conducted by Dr. Dismukes do not provide reliable support for the O&M and A&G expense adjustments proposed by the AG. The Commission further agrees with the Utilities and finds that Dr. Dismukes' analyses are not tied to any of AG witness Mr. Effron's specific proposed adjustments and do not bear on his specific proposals. Dr. Dismukes also did not identify specific expenses of the Utilities that are imprudent, inefficient, or excessive. As well, there are questions about whether the peers identified in the analyses are actually peers of the Utilities. The Commission finds that the analyses conducted by Dr. Dismukes do not provide independent support for the O&M and A&G expense adjustments proposed by the AG.

VI. RATE OF RETURN

A. Overview

Companies' Position

Each of the Companies propose modest increases in their overall rates of return on rate base. Peoples Gas proposes an increase from 6.67% to 7.21% based on a capital structure comprised of 50.33% common equity at a cost (a rate of return on common equity or "ROE") of 10.25%, 46.51% long-term debt at a cost of 4.32%, and 3.16% short-term debt at a cost of 1.19%. North Shore proposes an increase from 6.72% to 6.89% based on a capital structure comprised of 50.48% common equity at a ROE of 10.25%, 38.94% long-term debt at a cost of 4.13%, and 10.58% short-term debt at a cost of 1.06%. NS-PGL IB at 94-95.

Only Staff and CCI have addressed directly the Companies' cost of capital arguments. The Companies' capital structures are not disputed. The Companies and Staff are in agreement on North Shore's long-term debt costs. The Companies and Staff disagree, however, on the Companies' short-term debt costs and Peoples Gas' long-term debt costs. Staff proposes substantially lower rates of return on rate base, 6.54% for Peoples Gas and 6.23% for North Shore, by virtue of its proposal to reduce the Companies' ROE from 9.28% to 9.00%. CCI proposes a slightly smaller reduction in the Companies' ROE – from 9.28% to 9.15%. (CCI did not address short-term or long-term debt costs in its briefs.) NS-PGL IB at 105.

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 one of the Companies' recent rate cases 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.'

Docket Nos. 09-0166/09-0167 (Consol.), Order at 89-90 (citations omitted). Accord Docket Nos. 12-0511/12-0512 (Consol.), Order at 181-182.

Staff's Position

Staff submitted the testimony of Ms. Janis Freetly regarding the Companies' cost of common equity, capital structures, and overall weighted average costs of capital ("WACC"). Staff agreed with North Shore's proposed embedded cost of long-term debt of 4.13%. Staff contested the cost of long-term debt for Peoples Gas, and proposed a 4.26% embedded cost of long-term debt. Staff also contested both Companies' costs of short-term debt and costs of common equity. Staff proposed a 0.74% cost of short-term debt for North Shore and 0.91% for Peoples Gas. Staff's estimate of the rate of return on common equity for both Peoples Gas and North Shore is 9.05%.

CCI's Position

Though disputes remain regarding the Companies' cost of debt, the principal cause of the Companies' excessive proposed rate of return is a result-oriented approach exemplified in the flawed cost of common equity estimate presented by the Companies' witness Paul Moul. *See* NS-PGL Ex. 34.0 (Gast) at 3:43-5:99 (cost of debt) and generally PGL Ex. 3.0 (Moul), NS-PGL Ex. 9.0 (Moul), NS-PGL Ex. 35.0 (Moul) (*re* cost of equity).

B. Capital Structure

Companies' Position

As shown in their respective cost of capital schedules, the Companies and Staff agree on the following capital structures. NS-PGL Exs. 18.1N & 18.1P; Staff Ex. 8.01. No party disputed these structures.

	Peoples Gas	**North Shore**
Common Equity	50.33%	50.48%
Long-Term Debt	46.51%	38.94%
Short-Term Debt	3.16%	10.58%

According to the Companies, these structures are similar to their currently authorized ones. Docket Nos. 12-0511/12-0512 (Consol.), Order at 182. According to Staff, these structures "reasonably balance the cost advantage of tax deductible interest expense that comes from employing debt as a source of capital against the financial strength needed to raise capital under most capital market conditions that comes from employing common equity as a source of capital." Staff Ex. 3.0 at 3-4; Staff Ex. 8.0 at 2.

Staff's Position

Staff accepted the Companies' proposed capital structures. Staff IB at 43; NS-PGL IB at 95-96.

Commission Analysis and Conclusion

The Commission finds that the Companies uncontested capital structure is supported by the evidence and is hereby adopted.

C. Cost of Short-Term Debt

Companies' Position

The Companies estimate their 2015 costs of short-term debt to be 1.06% for North Shore and 1.19% for Peoples Gas based on forecasts published by the credit rating agency *Moody's*. NS-PGL Ex. 18.0 at 4 (table); NS-PGL Exs. 18.2N & 18.2P. The Companies argue that the credit rating agency interest rate forecasts the Companies relied on to estimate their costs in 2015 are verifiable and unbiased, and that these types of forecasts are "used by investors to formulate their expectations for the future." NS-PGL Ex. 35.0 at 2. The Companies state that such forecasts are an eminently reasonable basis to predict their costs in the future. NS-PGL IB at 96.

The Companies argue that Staff's proposed short-term debt costs should be rejected because they are based on historical "spot day" measurements to forecast capital costs in a future test year, which is arbitrary and unreliable. *Id.* The Companies point out that Staff itself recognized that relying on historical data "will necessarily be arbitrary" because the analyst must choose the historical timeframe for the data. *See* Staff Ex. 3.0 at 28. Basing a forecast on historical data will produce the "correct" result only by chance. *Id.* at 28. Recognizing that spot data "is exposed to inefficiencies from a number of sources" on any given day, the Commission has asked to be informed of "the conditions or financial climate of the spot day and whether any of these might cause material market inefficiencies." Docket Nos. 09-0166/09-0167 (Consol.), Order at 125-126. Staff did not attempt to make this showing with respect to its spot day interest rate measurements.

The Companies dispute Staff's positions that "current" interest rates are better predictors of future interest rates than published forecasts like *Moody's*, and that it is impossible to forecast interest rates because such forecasts are too often "inaccurate." *See* Staff Ex. 3.0 at 4; Staff Ex. 8.0 at 4. The Companies argue that the fallacy of Staff's position is that the accuracy of forecasts can be determined only with hindsight. A forecast represents the best estimate by the forecaster with the information then available. The fact that intervening events cause future rates to differ from a forecast does not render the forecast inaccurate when it was made. The Companies explain that nothing that depends on future events can be forecasted "with certainty" because no one can know "with certainty" what the future events will be, but this does not mean that forecasts are not accurate based on the information available when they are made. NS PGL IB at 97.

The Companies argue further that all Staff's "random walk" theory proves is that on any given day, it is impossible to know whether intervening events will cause a forecast to be wrong on the high side or the low side or by how much. If a forecast's performance in hindsight is truly random, as Staff claims, then there is no reason to believe that today's forecasts are either too low or too high. What is important is the forecast's credibility and objectivity. *Id.* at 98.

The Companies point out that Staff did not challenge the credibility or objectivity of the *Moody's* short-term debt forecasts on which the Companies relied. PGL Ex. 20.0 at 9. Staff instead points to variance in the forecasts of 10-year Treasury yields for the fourth quarter of this year as evidence that interest rate forecasting is not reliable. Staff Ex. 8.0 at 5-6. The Companies state that Staff's evidence does not prove its conclusion. Rather, the variation is a product of Staff's arbitrary selection of forecasts, namely "the most easily obtainable sources Staff was able to access in the limited time available." *Id.* at 5 n.4. The fact that two of the four forecasts Staff selected were significantly different than the other two suggests that more inquiry was required to determine the reliability of the outliers. Had it engaged in that inquiry, the Companies argue that Staff could have determined whether the *Forecasts.org* and *EconomicOutlookgroup.com* forecasts (2.28% and 3.50%, respectively) were reliable, as compared to the Freddie Mac and *Survey of Professional Forecasters ("Survey"*) forecasts (2.60% and 2.80%, respectively). NS-PGL IB at 98.

Finally, the Companies argue that Staff's objection to the use of interest rate forecasts for debt costs in a future test year is flatly inconsistent with Staff's reliance on forecasts in its cost of equity analyses, including (1) the "expected" quarterly dividends of the proxy group of delivery Companies used in its DCF model (Staff Ex. 3.0 at 10-11 & Sched. 3.04); and (2) gross domestic product ("GDP") inflation and GDP growth forecasts from the Energy Information Administration ("EIA"), Global Insight and the Survey *(Id.* at 16) used in its CAPM model. Forecasts from credible and objective sources are reliable for the purpose of establishing a utility's cost of capital in a future test year. NS-PGL IB at 98-99.

The Companies thus maintain that the record strongly supports basing the Companies' short-term debt costs on *Moody's* forecasts instead of a short-term debt rate selected by Staff on a single data several months ago.

<u>Staff's Position</u>

According to Staff, the cost of short-term debt is 0.74% for North Shore and 0.91% for Peoples Gas. Staff Ex. 8.0, 2-3, Sch. 8.01. The interest rate on short-term debt for both North Shore and Peoples Gas is based on commercial paper rates at the time of borrowing. To estimate the Companies' cost of short-term debt, Staff started with the June 12, 2014, 0.24% annual yield on 30-day A2/P2 nonfinancial commercial paper. (Staff Ex. 3.0, 5.) Then, Staff added the annual percentage cost of bank commitment fees to the annual commercial paper yield. Staff divided the amount in fees by the updated average 2015 balance of short-term debt projected to be outstanding to derive the commitment fees in percentage terms. For North Shore, adding the resulting 50 basis points to the 0.24% commercial paper yield produces a cost of short-term debt of 0.74% (0.24% + 0.50% = 0.74%). (Staff Ex. 8.0, 2-3.) For Peoples Gas, adding the resulting 67 basis points to the 0.24% commercial paper yield produces a cost of short-term debt for Peoples Gas of 0.91%.

The Companies' calculation for North Shore is 1.06% and for Peoples it is 1.19%. The parties agree that the Companies relied on forecasted commercial paper rates to estimate the cost of short-term debt for each of the Companies. Staff states that the Companies' interest rate forecasts have not been accurate. For example, in its 2011 rate cases, the Companies forecasted that the 30-day A-2/P-2 commercial paper rate would average 1.95% in 2012. In contrast, the 30-day A-2/P-2 commercial paper rate averaged 0.46% that year, which changed little from the January 2011 rate of 0.38%. In its 2012 rate cases, the Companies forecasted that the 30-day A-2/P-2 commercial paper rate would average 0.79% in 2013. In contrast, the 30-day A-2/P-2 commercial paper rate averaged 0.30% that year, even lower than the March 2012 rate of 0.45%. Staff Ex. 3.0 at 4.

In summary, Staff argues that the Companies' proposal to base the cost of new short-term debt issues on interest rate forecasts should be rejected in favor of recent actual short-term interest rates because the latter have proven to be more accurate predictors of future interest rates than the former. Staff Ex. 8.0 at 3-4.

Commission Analysis and Conclusion

The Commission finds that Staff's predictions of the cost of short term debt are reasonable, supported by the evidence, and are hereby adopted. Staff's predictions have been far more accurate in recent years than the Companies'. The short term interest rates which the Companies have urged us to incorporate in their rate structures relying on estimates by forecasting services have consistently overstated the actual interest rates that existed in the market place during the periods in question. The Commission finds that the cost of short term debt for North Shore should be .74%. The cost of short term debt for Peoples should be .91%.

D. Cost of Long-Term Debt

Companies' Position

North Shore (Uncontested)

A utility's forecasted cost of long-term debt is comprised of two components, the "embedded" cost of pre-existing debt issuances and the forecasted cost of issuances expected to occur during the test year (if any). North Shore's 2015 long-term debt cost forecast is 4.13%, and is based entirely on existing issuances because North Shore plans no new issuances in 2015. NS Ex. 2.3. The Companies and Staff agree on a long-term debt cost of 4.13% for North Shore. Staff Ex. 3.0 at 6-7; NS-PGL Ex. 2.0 at 7.

Peoples Gas

Including the forecasted costs of its planned issuances in 2015, Peoples Gas originally forecasted its cost of long-term debt to be 4.72%. PGL Ex. 2.3. Due to the actual pricing of certain debt and newer forecasts, however, Peoples Gas' proposed long-term debt cost fell from 4.72% (PGL Ex. 2.3) on direct to 4.32% (NS-PGL Ex. 34.2P) on rebuttal. The late August price of Peoples Gas' Series BBB, 4.21% was lower than both the Utility's forecasted price of 4.72% and Staff's 4.66% based on the June 11, 2014 actual rate. NS-PGL Ex. 34.0 at 3.

Staff proposed a 4.36% cost for Peoples Gas' long-term debt based on the June 11, 2014 spot day yield on A-rated bonds. Staff Ex. 3.0 at 6-7. The Companies argue that Staff's approach is inconsistent and arbitrary. NS-PGL IB at 100. While Staff agreed that the actual pricing of issuances should be used as it became known, Staff applied the 3.90% cost Peoples Gas obtained on its Series VV municipal bond remarketing in July to the Series WW municipal bond remarketing Peoples Gas does not expect to make until August 2015. Staff used the actual cost of Peoples Gas' Series VV remarketing as the forecasted cost for its Series WW remarketing instead of adjusting "current" municipal bond yields from *Vanguard* "for the difference in years to maturity on the proposed new issuances," as Staff did on direct. *Compare* Staff Ex. 8.0 at 7 *with* Staff Ex. 3.0 at 6-7.

The Companies note that this inconsistent mixing of methods avoided any changes to Staff's initial position based on June 11, 2014, actual interest rates. NS-PGL IB at 100; see Staff Ex. 8.0 at 7. The Companies argue that absent a sufficient rationale for the change, which has not been presented here, the Commission should insist on consistency of method in the highly complex area of corporate finance, which is the subject of many theories and data sources. Indeed, forecasting the cost of debt is itself "highly dependent on analyst judgment as to the inputs, and therefore subject to manipulation." Docket Nos. 09-0166/09-0167 (Consol.), Order at 123. For these reasons, the Companies urge the Commission to adopt their proposed long-term debt forecasts, even though the result will be a slightly lower cost for Peoples Gas (4.32% instead of 4.36%).

<u>Staff's Position</u>

The Companies and Staff agree that 4.13% is a reasonable estimate of North Shore's embedded cost of long-term debt for average 2015. Staff Ex. 3.0 at 6; NS Ex. 2.0 at 7. The Companies and Staff do not agree on the embedded cost of long-term debt for Peoples Gas, due to the Companies' use of forecasted interest rates for the anticipated 2015 issuances.

Staff and the Company agree on the interest rates for all long-term debt issues except those planned for 2015. Staff Ex. 8.0 at 7, Sch. 8.02P. Peoples Gas completed the pricing for the Series BBB bonds in August, with the actual interest rate set at 4.21%, after Staff filed its rebuttal testimony. NS-PGL Ex. 34.0 at 3. Hence, the interest rate for the Series BBB on line 12 of Staff Schedule 8.02P should be changed from 4.66% to 4.21% to reflect the actual interest rate. This change reduces the embedded cost of long-term debt for Peoples Gas from 4.36% to 4.26%. Attachment A.

The interest rates for the planned 2015 issuances should be based on recent actual interest rates. For the tax exempt Series WW planned to be issued in 2015, Ms. Freetly used the actual 3.90% interest rate that the Company recently obtained on the similar tax exempt Series VV. Staff Ex. 8.0 at 7, Sch. 8.02P, line 13. For the non-tax exempt Series CCC planned issuance for 2015, Ms. Freetly used the current yield on 30-year A-rated corporate bonds of 4.66%. Staff Ex. 3.0 at 7; Staff Ex. 8.0 at 7; Sch. 8.02P, line 14.)

Forecasted interest rates should not be used for estimating the cost of the planned 2015 issuances of long-term debt for Peoples Gas. Academic research has shown that forecasters' predictions of future movements of interest rates are inaccurate. Indeed, one financial text states, "forecasting interest rates is a perilous business. To their embarrassment, even the top experts are frequently wrong in their forecasts." Forecasts are frequently wrong even in the direction, let alone the magnitude and timing, of future interest rate changes. For example, the November 1, 2013 Blue Chip forecasts that Company witness Moul relied on (NS and PGL Ex. 3.12, 2) is already proving to be inaccurate. Blue Chip forecasted increasing yields from the fourth quarter 2013 through the second quarter of 2014. However, the actual yields have fallen over that time period.

Commission Analysis and Conclusion

The Commission finds and concludes that 4.13% is a reasonable estimate of North Shore's embedded cost of long-term debt for average 2015 and is supported by the evidence.

The Commission finds that Staff's estimate of the cost of Peoples' long term debt is compelling and supported by the evidence. While the Commission agrees that it is unlikely that current interest rates for long term debt will continue to be available in 2015, the Commission also believes that predicting the direction, magnitude, or timing of future interest rate changes with accuracy is not possible. The Commission observes that the record demonstrates that professional forecasting services relied on by the Companies have consistently over estimated future rates in recent years. Current interest rates have proven to be better predictors of future interest rates than professional forecasters. Therefore, the Commission concludes that the appropriate estimate of Peoples cost of long term debt should be 4.26%

E. Cost of Common Equity

Companies' Position

The Commission "is charged by the legislature with setting rates which are 'just and reasonable' not only to the ratepayers but [also] to the utility and stockholders." *BPI II*, 146 Ill. 2d at 208-209. Ratesetting by the Commission "involves a balancing of the investor and consumer interests." *Citizens Utility Board, et al. v. Illinois Commerce Comm'n,* 276 Ill. App. 3d 730, 736, 658 N.E.2d 1194 (1994) (quoting *Illinois Bell Tel. Co. v. Illinois Commerce Comm'n,* 414 Ill. 275, 287, 111 N.E. 2d 329 (1953)).

The Companies are entitled to fair and reasonable returns on their investment, returns that are "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." *Bluefield Water Works & Improvement Co. v. Public Service Comm'n of the State of West Virginia*, 262 U.S. 679, 693 (1923). The returns authorized by this Commission "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." *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). This Commission "fully embraces the principles set forth" in *Bluefield and Hope. Consumers Ill. Water Co.*, Order at 41, Docket 03-0403 (April 13, 2004).

The Commission has recognized that its decisions directly affect the Companies' credit ratings and the capital costs that they pass on to their customers:

> We are cognizant that the Commission's ratemaking decisions are increasingly important to the Companies' ability to maintain investment grade credit ratings and reasonable capital costs. Indeed 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. . . . [S]tate commissions play a critical and relevant role in defining the market for utility capital, and we understand that this Commission's decisions play a larger role in setting the Companies' actual capital costs. <u>The bottom line impact of setting a rate of return too low, unless warranted, could have a deleterious [effect] on a utility's ability to deliver quality service as well as higher credit costs that will make their way to each ratepayer[']s bill.</u>

Docket Nos. 11-0280/11-0281 (Consol.), Order at 137 (emphasis added). Accordingly, "[a]llowing a utility the opportunity to recovery 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." *Id.* at 5.

Understood properly, the courts' admonishment that the Commission balance customer and investor interests in ratemaking does not mean, as the AG argues, that the Commission can consider adjustments to a utility's ROE in order to reduce rates paid by low income customers. AG IB at 6-7. The Companies argue that supportive ROE decisions are in the interest of both customers and shareholders by maintaining the Companies' financial strength and their access to capital at reasonable cost. The Commission, however, has many ways to address customer impact, such as its policies on energy efficiency and customer matters such as bill payment NS-PGL RB 82.

Traditionally, the Commission has established the utility's authorized return on equity by employing financial models designed to estimate a firm's market cost of equity. In recent cases, however, the Commission has recognized that the financial models have theoretical limitations and are "highly dependent on analyst judgment as to the inputs, and therefore are susceptible to manipulation. Although these models provide the best information of what we need for the purposes at hand, their limitations require that we also consult general financial market information to ensure that the model results presented us are…reasonable rates of return on equity based on the models that we deem appropriate for our consideration." Docket Nos. 09-0166/09-0167 (Consol.), Order at 123. More recently, the Commission reiterated that it will consider current market conditions and trends, including the returns recently authorized for other Companies, in addition to the financial model results, "provided the data are verifiable and unbiased." Docket Nos. 12-0511/12-0512 (Consol.), Order at 205. Such general market data "provide relevant comparative information" for the Commission's assessment of the parties' cost of equity evidence. *Id.*

Earlier this year, the Federal Energy Regulatory Commission ("FERC") reached similar conclusions, rejecting the "mechanical application" of the DCF model and expanded its "zone of reasonableness" inquiry to include results from the Risk Premium, CAPM and Expected Earnings approaches as well as "record evidence of state commission-approved ROEs." *Martha Coakley, Mass. Attorney Gen.*, Docket No. EL11-66-001, 147 FERC ¶ 61,234 (2014), at 142 148

The "verifiable and unbiased" evidence of general market conditions and trends in this case uniformly lead to the conclusion that the Companies' cost of equity will be higher in 2015 than it was in 2013, when the Commission last set the Companies' rates. Stellar stock market performance and increasing strength in the leading economic indicators point to an improving economy. PGL Ex. 3.0 at 20-21. Treasury and utility bond yields are projected to rise due to the Federal Reserve's tapering of its program to support the economy in response to the 2008 financial crisis. *Id.* at 28, 31-32; NS-PGL Ex. 19.0 at 11-12.

Consistent with these leading economic indicators, forecasted returns for the Delivery Group are projected to average 10.50%, which is substantially higher than the Companies' current authorized return of 9.28%. NS-PGL Ex. 19.0 at 4-5. This forecasted growth is consistent with growth in the average authorized returns for natural gas Companies from 9.68% in 2013 to 9.71% in the first half of 2014. *Id.* at 3. Indeed, the average return in the second quarter of 2014 was 9.84%. CCI Ex. 2.0 at 5 (table).

The Companies find Staff's continued objections to the consideration of ROEs authorized for other Companies "grossly exaggerated" for at least three reasons. First, Staff's position is contrary to this Commission's and now FERC's pronouncements that other authorized returns should be considered as "indicators" to ensure that the return set in an individual case meets constitutional standards. Second, the Companies' evidence of other returns was restricted to 2013 and 2014 and therefore captured "market fundamentals that are closely aligned with the present." NS-PGL Ex. 35.0 at 4. The Companies' evidence was also based on a large sample, which encompassed the diversity of risk characteristics and minimizes the effect of any given factor. *Id.* Neither Staff nor CCI disputed that the Companies' risk characteristics are reasonably similar to natural gas distribution companies generally. Third, credit ratings among Companies are "tightly clustered" and do not represent a likely source of variation in authorized returns. The same is true for flotation costs, as few commissions adjust for them. *Id.* at 4-5.

For all of these reasons, the Commission should continue its practice of considering general market conditions and trends, including recent authorized returns for other Companies, in its assessment of the parties' positions on the Companies' authorized return and the evidence underlying those positions. Doing so does not mean, as Staff and CCI claim, that the Commission would be basing its ROE decisions on such data. NS-PGL IB at 102-104.

Moreover, the Companies explain that Staff's own contextual information in the form of various calculations of a cost of equity for the U.S. market "as a whole" should be rejected. NS-PGL RB at 82-83. Staff claims that a 9.0% ROE for the Companies is "representative of the return investors can earn on other investments of comparable risk because the overall U.S. market cost of equity is anywhere from 8.80% to 9.52%. Staff IB at 57-58. Staff fails, however, to explain how the Commission is to use this measurement to determine the return on investments of risk comparable to the Companies, other than the unsupported claim that the "market as a whole" is riskier than gas distribution Companies. *Id.* at 58.

Moreover, Staff did not explain how these published measurements of the "market" cost of equity deviated so dramatically from Staff's own calculation of the "expected rate of return on the market" for purposes of its CAPM model. NS-PGL RB at 83. Based on a DCF analysis on the firms in the S&P 500 Index, Staff calculated that cost to be 12.43%. Staff Ex. 3.0 at 17. By comparison, the Companies calculated the total return on the market of U.S. equities to be 10.90%. PGL Ex. 3.0 at 33.

The Companies argue that the most direct calculation of investments of risk comparable to the Companies is Mr. Moul's Comparable Earnings model, which estimates "the returns realized by non-regulated firms with comparable risks to a public utility." PGL Ex. 3.0 at 35. Using six categories of comparability of risk to the Delivery Group and reviewing both historical and forecasted returns for non-utility companies, Mr. Moul calculated a 10.30% ROE for investments of comparable risk to the Companies, which is very close to his recommendation based on his other models. *Id.* at 37.

The Companies conclude that all of these considerations support an increase of the Companies' ROE to 10.25%.

<u>Proxy Group Analysis</u>

Because the Companies' stock is not publicly traded, their cost of equity must be estimated using mathematical models applied to a proxy group of publicly-traded companies with investment risk similar to that of the Companies. NS Ex. 3.0 at 4. Mr. Moul based his 10.25% ROE recommendation using three market-based mathematical models based on a proxy group of publicly-traded gas and electric distribution Companies (the "Delivery Group"): the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM") and the Risk Premium ("RP") model. Mr. Moul developed inputs to the models based on his independent evaluation of the types of historical, current and forecasted information that is readily available to and routinely relied upon by investors and financial analysts. Mr. Moul presented the following calculations of the Companies' market cost of equity:

Model	Cost
DCF	9.71%
RP	11.50%
CAPM	9.62%
Average	10.25%

PGL Ex. 3.0 at 6.

Staff accepted the Companies' Delivery Group for the purpose of running its cost of equity models. Staff Ex. 3.0 at 9, 18. CCI, however, used a different proxy group comprised of all but two of the Delivery Group companies. One company was properly excluded because it became an acquisition target in the time between the Companies' and CCI's analyses. CCI also excluded Laclede Group because it is pursuing an acquisition of another company. CCI did not justify this exclusion, pointing only to the fact that a credit rating agency had placed the company on watch for potential downgrade. *See* CCI Ex. 2.0 at 9-10. CCI did not provide any evidence that Laclede Group's proposed acquisition impacted the company's fundamentals. NS-PGL Ex. 19.0 at 18.

The weight of the evidence favors the use of the Delivery Group to estimate the Companies' cost of equity. CCI's reliance on a different proxy group was not justified and therefore its analyses are not comparable to those of the Companies or Staff. Accordingly, the Commission should disregard CCI's analyses.

DCF Analysis

The DCF model expresses the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return, which for common stock is the dividend yield plus future price growth. NS Ex. 3.0 at 14. Mr. Moul used a six-month average dividend yield for the Delivery Group, adjusted by three generally accepted methods to reflect investors' expected cash flows, and averaging the three adjusted values. *Id.* at 15-16. 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 17-18. He focused on forecasts of earnings *per* share growth because empirical evidence supports it and because they are most relevant to investors' total return expectations. *Id.* at 18-20. He selected 5.25% to reflect improving business conditions. *Id.* at 20.

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 22-25.

The Companies argue that Staff's and CCI's DCF model results are too low to be credible, and are the result of inappropriate or biased inputs, as well as unsupported methodologies.

Staff's Failure to Adopt Mr. Moul's Dividend Yield is Unsupported

In response to Mr. Moul's renewed criticism of Staff's continued reliance of spot day stock prices to develop its DCF dividend yield, Staff chose not to defend its practice. Instead, "in order to reduce issues in this proceeding," Staff stated that would "adopt" Mr. Moul's "6-month average dividend yield of 3.89%." Staff Ex. 8.0 at 11. Staff thus implied that it was conceding to the dividend yield that Mr. Moul used in his DCF model, but this was not the case. Mr. Moul actually used a dividend yield of 4.00% "to reflect the prospective nature of the dividend payments." PGL Ex. 3.0 at 16; see PGL Ex. 3.6. The Companies state that Staff did not explain, much less justify, why it did not "adopt" Mr. Moul's actual dividend yield. NS-PGL IB at 107.

Staff Makes Unsupported Departures From Its Prior DCF Methodologies Resulting in Reduced Results

The Companies note that the Commission has been troubled in the past by Staff's departures from established methodologies that result in lower costs of equity through the models. For example, in the Companies' 2009 rate cases, the Commission rejected Staff's DCF result because Staff had departed from its constant-growth version of the model without justification. *Peoples Gas 2009 Order* at 124-125. The Companies argue that in this case, Staff has once again departed from past practice without sufficient explanation and the result is a lower DCF result.

In prior cases, including the Companies' last four rate cases, Staff has based its DCF growth component on security analyst forecasts of earnings *per* share ("EPS") growth for the proxy group. *Peoples Gas 2012 Order* at 198 (Zacks and Reuters); *Peoples Gas 2011 Order* at 126 (Zacks); Peoples Gas 2009 Order at 104 (Zacks); *Peoples Gas 2007 Order* at 78 (Zacks, Yahoo and Reuters). In this respect, Staff's approach has been consistent with that of the Companies, though they have not necessarily agreed upon which forecasts to use in a given case.

In this case, however, Staff calculated its DCF growth rate differently. First, Staff did not rely on Zacks and/or Reuters EPS growth forecasts as it did in the past. Instead, it relied on the group of four published EPS growth forecasts identified by Mr. Moul, which included Zacks but not Reuters. Instead of averaging the Value Line EPS growth forecast with the other EPS growth forecasts, however, Staff first averaged that forecast with Value Line growth forecasts for several other parameters in order to arrive at an average Value Line growth forecast. Staff Ex. 3.0 at 9. This average Value Line growth forecast of 4.47% was over 100 basis points lower than the Value Line EPS growth forecast of 5.58%. *See* PGL Ex. 3.8. Staff then averaged its average Value Line growth forecast with the EPS growth forecasts from I/B/E/S First Call (4.87%), Zacks (5.10%) and Morningstar (4.70%) to arrive at its DCF growth rate of 4.77%. Had Staff simply averaged the four EPS growth forecasts, its DCF growth rate would have been 5.06%. PGL Ex. 3.0 at 19.

By contrast, Mr. Moul considered both historical and forecasted growth data and did not simply average selected values. Because "[e]arnings *per* share growth is the primary determinant of investors' expectations regarding their total returns in the stock market," Mr. Moul focused on EPS growth forecasts. With the EPS growth forecasts ranging from 4.70% to 5.58%, Mr. Moul selected a DCF growth component of 5.25% to reflect improving business conditions. PGL Ex. 3.0 at 19-21.

Staff did not claim that the Value Line EPS growth forecast was biased, inaccurate or otherwise faulty. In fact, when Mr. Moul objected to the mishmash nature of Staff's DCF growth component, Staff witness Ms. Freetly agreed to exclude the Value Line growth forecasts for book value *per* share, cash flow *per* share and percent retained to common equity. Staff Ex. 8.0 12. She insisted, however, on blending the Value Line EPS growth forecast with the Value Line growth forecast for dividends *per* share ("DPS"). *Id.* at 12. By averaging the much lower DPS rate (3.92%) with the EPS rate (5.58%), Staff reduced the Value Line component to 4.75% and its DCF growth rate from 5.06% to 4.82%. *Id.* at 13:237.

Staff claims, without citation to the record, that it has used forecasted DPS growth rates in the DCF model "when available from Staff's growth rate sources." Staff IB at 51.

Yet Staff can identify only one instance from over 23 years ago. *Id.*, citing Order, Docket No. 90-0169 (Mar. 8, 1991).

Staff also claims that it "usually relies on growth rates from Zacks and Reuters for the DCF model, which do not provide projected growth in dividends *per* share; they only publish growth in earnings *per* share." *Id.* If this is true, then it must also be true that Staff does not use DPS growth forecasts for the growth component of the DCF model.

Additionally, the Companies argue that Staff introduced a double counting issue into its DCF model because the forecasted dividend yield for the Delivery Group is already included in the DCF model. Had Staff limited its averaging to the EPS forecasts, its DCF growth rate would have been 5.11% instead of 3.89%. NS-PGL Ex. 19.0 at 8. Coincidentally, had Staff followed its longstanding practice and relied on the Zacks EPS growth forecast (a Reuters forecast is not in the record), its DCF growth rate would have been 5.10%. *Id.*

<u>Mr. Moul's Leverage Adjustment is Methodologically Sound</u>

Consistent with his past analyses presented to this Commission, Mr. Moul has included a "leverage" adjustment in his DCF and CAPM models. PGL Ex. 3.0 at 21-26, 30-31. The Companies acknowledge that the Commission has not accepted this adjustment, but the Companies continue to urge its consideration because its underlying logic is unassailable.

The leverage adjustment is necessary to correct the measurement error that occurs when a market cost of equity that is based on the market value capital structure of the Delivery Group is applied to the Companies' book value capital structure. The market cost of equity assumes a capital structure with more equity, about 60%, and less risk that the Companies' book value capital structures, which include about 50% equity. PGL Ex. 3.9. If the Delivery Group's market cost of equity is 10.25% as estimated by

Mr. Moul, then the Companies would have to recover 10.25% times the market value of their equity to earn their market-based return. But because of the regulatory practice of applying the market-based cost of equity to the utility's book-value capital structure, the Companies by definition cannot earn their market-based return. PGL Ex. 3.0 at 22.

The leverage adjustment makes the Companies' market cost of equity applicable to their book value capital structures by accounting for the lower equity ratios and higher risk in those structures. In this case, the DCF return of 9.25% must be adjusted upward by 46 basis points to allow the Companies to earn their market cost of equity applied to their market value capital structures. *Id.* at 25- 26. Likewise, the CAPM beta must be adjusted upward from 0.69 to 0.75. *Id.* at 30-31.

Staff and CCI raise a number of familiar but unfounded objections to the leverage adjustment. First, Staff and CCI argue that Companies are allowed to earn a return only on the amount actually invested in providing utility service and the leverage adjustment would provide a return on amounts that are not invested in the Companies, contrary to Illinois law. Staff IB at 62-63; CCI IB 24-25. The Companies claim that this is pure sophistry. The Companies are not trying to earn on dollars that they have not invested;

rather, they are trying to earn the full cost of equity that is associated with their book value investment. NS-PGL RB at 87.

Second, Staff speculates that correcting the leverage mismatch between market returns and book value capital structures would result in a "never ending upward spiral" in utility market values and authorized ROEs. Staff IB at 62-63. The Companies argue that there is no basis for Staff's assertion that the "investor required return" is exactly the product of the authorized return and the book value of the utility's equity. If that was true, "then a stock price would always equal the firm's book value." NS-PGL Ex. 35.0 at 7. Of course, this is not true, as demonstrated by the prevalence of natural gas utility stocks trading at multiples of book value; the average multiple over the last 56 years is 1.72. *Id.* at 7-8. Clearly, authorized natural gas utility ROEs are not routinely set at Staff's notion of the "investor required return," and the result has not been a "never ending upward spiral" of market values and ROEs. NS-PGL RB at 87.

Third, Staff argues that a firm can have only one level of "intrinsic" risk. Staff IB at 66-67. The Companies do not disagree. However, the Companies state it is undeniable that if the market priced the Companies' equity assuming their book value capital structures, the cost would be higher than it is when the market assumes their market value capital structures. NS-PGL Ex. 19.0 at 15. A firm's financial risk as perceived by the market changes when the firm's capital structure changes. *Id.* at 16. The market will perceive more financial risk with an equity ratio of 50% than with an equity ratio of 60%. *Id.* at 17.

<u>CCI Failed to Support Its Use of a Non-Constant Form of the DCF Model</u>

In addition to two versions of the constant growth form of the DCF model, CCI presented a non-constant growth version. In the Companies' 2010 test year rate cases, the Commission rejected Staff's reliance on a non-constant growth form of the DCF model, noting that the constant growth model "has been favored by the Commission for years." Docket Nos. 09-0166/09-0167 (Consol.), Order at 124. The Commission found that Staff had not justified its departure from prior practice.

In contrast to the constant growth version of the DCF model, which assumes one, steady rate of future dividend growth, Staff's non-constant growth model assumes multiple stages of growth on the theory that, given the large difference between the near-term growth rates for the Gas Group and the expected long-term growth of the overall economy, the continuous sustainability of the near-term growth rates for the Gas Group is unlikely. Staff, however was unable to demonstrate the unsustainability of the analyst growth rates it relied on which we must assume took into account indicators of below average growth associated with the Gas Group, including earnings retention rates and risk/return. *Id.*

In addition, the Commission rejected "Staff's position that the non-constant growth form of the model must be used any time it can be claimed that analyst growth rates are not sustainable. Rather we will require a more robust showing that application of the constant model is appropriate." *Id.* at 125.

The Companies argue that CCI did not attempt to make this "more robust showing" required by the Commission for its non-constant growth model. To the contrary, Mr.

Gorman testified that his constant growth model "is a reasonable reflection of rational investment expectations over the next three to five years." CCI Ex. 1.0 at 21. He included a non-constant form of the model simply to reflect an "outlook of changing growth expectations." *Id.* at 21.

The Companies argue that for this reason alone, the Commission should disregard CCI's non-constant growth DCF model. NS-PGL IB at 109-110. If another reason was needed, the result of this model – 8.65% -- is far too low to be credible, even by CCI's own evidence of 2014 year-to-date gas utility ROEs, which average over 100 basis points higher. See CCI Ex. 2.0 at 5 (table).

Many Of CCI's DCF Results Are Far Too Low To Be Credible

The Commission has in the past rejected DCF results that are "anomalous." *Peoples Gas 2007 Order* at 92. Many of CCI's constant growth DCF rates for Delivery Group companies are so anomalous that they undercut the credibility of his DCF results. *See* NS-PGL Ex. 19.0 at 18 (table).

"It is a fundamental tenet of finance that the cost of equity must be higher than the cost of debt by a meaningful margin to compensate for the higher risk associated with common equity investment." NS-PGL Ex. 19.0 at 18-19. The six-month average yield on Baa-rated public utility bonds is 4.98%. *Id.* at 19. Even under Mr. Gorman's 30-year historical average equity risk premium of 3.80% (which is much lower than the more recent premiums in excess of 5.00%), his DCF results for 6 of the Delivery Group companies are far below the minimum expected cost of equity of 8.78%, much less the average 2014 authorized gas utility ROE of 9.71%. CCI Ex. 2.3. The Companies thus argue that these results should be disregarded.

CAPM Analysis

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 current forecasts and recent trends. NS Ex. 3.0 at 30-31. 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. NS Ex. 3.0 at 29-30. Mr. Moul developed his market premium of 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. NS Ex. 3.0 at 31-32.

The Companies argue that the Commission should reject Staff's CAPM result of 9.27% for two reasons. First, it is based on historical spot day interest rates as of October 31, 2013, which have no relation to what interest rates are likely to be in 2015. Second, Staff's unique "beta" measurement of systematic risk is biased because it uniformly results in lower CAPM results. NS-PGL IB at 111-113.

According to Staff, an interest rate, stock price or other datum from a single day in the recent past is a better predictor of what that data point will be in the future than the forecasts made by governmental and commercial analysts on which investors and analysts routinely rely. The Companies note that it is undeniably true that few if any forecasts are exactly right in hindsight. Staff provided no evidence that information from a single day in the past provides a more accurate prediction than forecasts do when they are made. Logic and common sense dictate otherwise. All that a given day's interest rate reflects is the cost of a certain type of debt capital on that day. The Companies conclude that it says nothing about what that cost of capital will be in the future. *Id.* at 112.

Again, the Companies argue that under the Commission's prior decisions the question is whether the data in question are "verifiable and unbiased." Peoples Gas 2012 Order at 205. Here, Staff rejected interest rate forecasts published by Blue Chip in favor of historical spot day rates. The Companies posit that the credibility and objectiveness of the Blue Chip forecasts is undisputable:

Blue Chip does not actually make forecasts of interest rates itself. Rather, Blue Chip conducts a monthly survey of noted economists from academic institutions, banking, brokerage, business consulting, financial institutions, investment advisory firms, and rating agencies. Presently, there are forty-eight (48) contributors to the Blue Chip survey. Blue Chip takes the results of its monthly surveys and publishes the consensus of these individual forecasts. The major attributes of Blue Chip are its independence, the influence it has on investors' expectations of future interest rates, and the objectivity of the survey that encompasses the wide range of viewpoints obtained from a broad sample of renowned economists. NS-PGL Ex. 35.0 at 3. Staff did not challenge these attributes of the Blue Chip forecasts, which were also used in CCI's CAPM model. *See* CCI Ex. 1.0 at 29. The use of such "verifiable and unbiased" data in determining the Companies' cost of equity is entirely appropriate and superior to relying solely on historical spot day data to establish that cost in a future test year. NS-PGL IB at 112.

For this reason alone, the Companies conclude, the Commission should reject Staff's CAPM model. Alternatively, it should be adjusted to incorporate either Mr. Moul's Blue Chip-based risk-free rate of 4.25% or Mr. Gorman's rate of 4.30%. PGL Ex. 3.0 at 32 33; CCI Ex. 1.0 at 29.

Furthermore, as the Companies have noted in prior cases, Staff is not content to rely on the "betas" – the theoretical measurement of the systematic risk of the Delivery Group – published by well-recognized sources like Value Line. In addition to the Value Line betas, Staff in this case used betas published by Zacks but adjusted them downward because "[s]ome empirical tests of the CAPM suggest that the linear relationship between risk, as measured by the raw beta, and return is flatter than the CAPM predicts." Staff Ex. 3.0 at 20. Staff also averaged in a "regression beta" of its own creation. The Companies argue that there is no need for this additional beta measurement and it is not a data point on which any investor relies. By contrast, Value Line betas are routinely relied on by investors and thus used in the actual pricing of stocks by the market. NS-PGL Ex. 19.0 at 13. Accordingly, both the Companies and CCI relied on Value Line betas alone. CCI Ex. 1.12.

The Companies state that of more concern is the fact that the Staff betas are routinely lower than the published betas. NS-PGL Ex. 35.0 at 7 (table). Thus, the only purpose served by Staff's lower beta, according to the Companies, is to reduce Staff's CAPM result. In this case, had Staff relied solely on the published betas, its CAPM result would have been 9.71% instead of 9.27%. NS-PGL Ex. 19.0 at 13. If Staff had based its CAPM on the Value Line betas as the Companies and CCI did, the result would have been 9.82%. *Id.* at 13. Thus, even if there was some value in using multiple beta models (see Staff Ex. 8.0 at 14-15), Staff's "multiple source" approach is invalid because of its downward bias.

Risk Premium

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. NS Ex. 3.0 at 25. Mr. Moul estimated a 5.25% prospective yield on A-rated utility bonds based on historical and forecasted yields. NS Ex. 3.0 at 26. Mr. Moul determined an equity risk premium of 6.25% 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. NS Ex. 3.0 at 26-28. Mr. Moul's risk premium analysis thus provided a cost of equity of 11.50%. NS Ex. 3.0 at 25.

Staff contends that the Risk Premium model is unreliable because the true mean of the market risk premium is unobservable and the result is influenced by the choice of historical period. The Companies respond that it is not necessary to establish the true mean because the risk premium approach is designed to align the risk premium with the level of forecasted interest rates. The risk premium rises as interest rates decline and the risk premium falls as interest rates increase. Mr. Moul's risk premium analysis is dynamic and does not rest upon a single risk premium that might be represented by the "true mean." NS-PGL Ex. 35 at 6. Second, Mr. Moul did not arbitrarily select any particular period to measure the risk premium with historical data. Rather, he used all available and reliable data in order to avoid the introduction of a particular bias into the results. *Id.*

Staff's Position

Staff witness Janis Freetly's estimate of the investor-required rate of return on common equity for Peoples Gas and North Shore is 9.05%. Staff's revised investor-required rate of return was derived by taking the average of Staff's revised 8.82% DCF estimate and 9.27% CAPM estimate results. Staff Ex. 8.0, Sch. 8.01. Ms. Freetly began her analysis with the data that the Companies' witness Mr. Moul used in his DCF and CAPM analyses while correcting the most significant flaws in those analyses. She applied both models to Mr. Moul's sample, the "Delivery Group." Staff Ex. 3.0 at 8.

DCF Analysis

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments. Because a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend prices that stock prices embody. The companies in the Delivery Group pay dividends quarterly. Therefore, Ms. Freetly applied a quarterly DCF model. Staff Ex. 3.0 at 8-9.

In order to reduce issues in this proceeding, Ms. Freetly revised her DCF analysis in rebuttal testimony. Staff Ex. 8.0 at 11-13. While Staff does not agree with Mr. Moul's position that stock prices measured over a longer time period are superior for measuring the investor-required rate of return on common equity, Ms. Freetly adopted Mr. Moul's 6-month average dividend yield of 4.00%. In addition, Ms. Freetly agreed to exclude the Value Line projected growth rates for book value *per* share, cash flow *per* share and percent retained to common equity from the growth rate used in her DCF analysis; although, Mr. Moul had testified in his direct testimony that he considered those growth rates in his own analysis before he disowned them in his rebuttal testimony.

Staff supports a revised investor-required rate of return on common equity for Peoples Gas and North Shore of 9.05%. Staff witness Ms. Freetly began her analysis with the data that the Companies' witness Mr. Moul used in his DCF and CAPM analyses while correcting the most significant flaws in those analyses. She applied both models to Mr. Moul's sample, the "Delivery Group." Staff Ex. 3.0 at 8.

However, Staff argues that despite Mr. Moul's protestations to the contrary, the *Value Line* projected growth in dividends *per* share ("dps") should not be ignored. As Mr. Moul indicated, the Delivery Group average *Value Line* projected growth rate of earnings *per* share ("eps") is higher than the Delivery Group average *Value Line* projected growth rate of dps. DCF theory holds that dividend growth will equal earnings growth when the payout ratio is constant. NS-PGL Ex. 19.0 at 8. He then indicates that *Value Line* projects declining dividend payout ratios for the Delivery Group. *Id.* at 10. Staff states that this explains why *Value Line*'s forecasted eps growth rate exceeds its forecasted dps growth rate. If the lower payout ratio persists, long-term dividend growth will eventually converge to the level of earnings growth. This is because growth is directly related to the earnings retention ratio: Growth = Rate of Return on New Investment x Earnings Retention Rate.

Nonetheless, Staff argues that this higher long term earnings growth cannot be achieved without slowing near term dividend growth. Because the DCF is a dividend discount model rather than an earnings discount model, ignoring the slowing in the growth of dividends that is necessary to increase the earnings retention rate, leads to an upwardly biased estimate of the investor-required rate of return on common equity.

Significantly, Mr. Moul did not contest the economic rationale for including dps growth in DCF analysis described in the preceding paragraph. Rather, he alleged that Ms. Freetly's proposal to include growth in dividends *per* share in the DCF growth rate is a first for Staff and is therefore a departure from Staff precedent in past rate cases. (NS-PGL Ex. 35.0, 5.) However, Staff points out that it has used growth in dividends *per* share in the DCF model when available from Staff's growth rate sources. *See e.g. Docket No. 90-0169*, Order at 97 (March 8, 1991).

Using the data presented by Mr. Moul on NS and PGL Ex. 3.8, Ms. Freetly first calculated the average *Value Line* growth projection by averaging the growth in eps and dps. She then computed the average of the growth rates from I/B/E/S First Call, *Zacks*, Morningstar and the average *Value Line* growth projection. The resulting growth rate estimate is 4.82%. Hence, Staff's 8.71% DCF cost of common equity estimate was derived by adding the 4.82% growth rate to Mr. Moul's 3.89% dividend yield.

In Staff's Reply Brief, Staff agreed that Mr. Moul's actual dividend yield was 4.00%, not the 3.89% that Ms. Freetly used in her rebuttal testimony. NS-PGL IB at 107. According to Staff, adding the 4.00% dividend yield to Staff's 4.82% growth rate produces a DCF cost of equity estimate of 8.82%.

<u>CAPM Analysis</u>

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Ms. Freetly supplemented Mr. Moul's *Value Line* betas with the *Zacks* betas and betas calculated using a regression analysis that the Commission has routinely adopted for the CAPM. Staff states that, because the *Zacks* beta estimate and the regression beta estimate are calculated using monthly data rather than weekly data (as *Value Line* uses), Ms. Freetly averaged the *Zacks* and regression results to avoid over-weighting betas calculated from monthly returns. She then averaged that result with the *Value Line* beta, which produced a beta for the Delivery Group of 0.64. Staff Ex. 3.0 at 17-21.

For the risk-free rate parameter, Ms. Freetly used the 3.66% yield on thirty-year U.S. Treasury bonds on October 31, 2013. Staff Ex. 3.0 at 15-17.

Finally, for the expected rate of return on the market parameter, Ms. Freetly conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market equals 12.43%. Staff Ex. 3.0 at 17. Inputting those three parameters into the CAPM, Staff's CAPM estimate of the cost of common equity for the Delivery Group is 9.27%. Staff Ex. 3.0 at 21; Sch. 3.06.

Staff points out that the Companies insist that the estimation of the risk-free rate should be based on forecasts rather than spot yields. NS-PGL Ex. 19.0 at 11-12. However, Staff argues that interest rates are constantly adjusting, and accurately forecasting the movements of interest rates is problematic, as discussed previously. In contrast, current U.S. Treasury yields, which Staff used to estimate the risk-free rate, are set directly by investors and reflect all relevant, available information, including investor expectations regarding future interest rates. Consequently, Staff states that investor appraisals of the value of forecasts are also reflected in current interest rates. Staff concludes that the Commission should continue to rely on current, observable market interest rates rather than the projected rates that Mr. Moul used in his analysis. Staff Ex. 8.0 at 13-14.

According to Staff, the Companies falsely contend that the interest rate forecasts are "verifiable and unbiased" and superior to relying solely on spot day data to establish the cost of equity in a future test year. (NS-PGL IB, 112.) Staff contends that the Companies' claim that the interest rate forecasts it relied upon are "unbiased" is demonstrably false. Also, Staff argues that there is no valid justification for disregarding investor expectations imbedded in objective, observable current market data in favor of a proxy for those expectations imbedded in speculative projections. Staff states that the forecasts Mr. Moul advocates are merely proxies for investor expectations. Proxies are a source of measurement error in cost of common equity estimation. Therefore, Staff argues proxies should only be used when the market factor in question is not directly observable.

Staff states that the Companies did not present any evidence that the *Value Line* betas are superior to Staff's. Because there is no inherently superior beta estimation methodology, multiple approaches result in less bias than merely relying on the higher *Value Line* betas. Hence, Staff concludes that the Commission should remain consistent with its past findings that use of multiple beta sources is beneficial to reduce measurement error and adopt Staff's beta in this proceeding. Staff IB at 53-55.

Leverage Adjustment

Mr. Moul argues that in order to apply a measurement of a return measured based on a firm's market-value capitalization compared to a book-value capitalization, the measurement must be adjusted before it is applied to the firm's capitalization measured based on book value. NS-PGL Ex. 19.0 at 17. His argument is effectively an espousal of fair-value rate making, which entails estimating the fair, or market, value of a utility's property and then applying a market ROE to that value. See., *e.g.*, *Union Electric Co. v. Illinois Commerce Comm'n*, 77 Ill.2d 364, 374-375 (1979). Section 9-210 of the Act put an end to fair-value ratemaking. 220 ILCS 5/9-210 ("For purposes of establishing the value of public utility property, when determining rates or charges, or for any other reason, the Commission may base its determination on the original cost of such property."). Mr. Moul's "leverage" adjustment would reverse that practice. The problem is that market to book ratio based adjustments to ROE would have the Commission fruitlessly "chase" market value. That would occur because market value is an inverse function of required rate of return and a direct function of expected cash flow. For example, if investors reduce their required rate of return, the market value will increase. If the Commission increases its authorized rate of return in reaction to that increase in market value, the utility's cash flow will increase, which in turn will lead to an even higher utility market value, which by Mr. Moul's reasoning would, necessitate an even greater upward adjustment to the authorized rate of return. These reactions -- investors reacting to the increased authorized ROR by raising market value and the Commission reacting to the increase in market value by raising the authorized ROR -- are mutually reinforcing, resulting in never ending upward spiral in both. Staff Ex. 8.0 at 17-20.

Another problem with the leverage adjustment is that it would boost authorized rates of return in response to successful diversification into non-utility businesses. Ms. Freetly used a hypothetical example to illustrate this phenomenon: a company that includes two business segments of equal book value and equal risk – a regulated gas delivery company that is expected to earn exactly the investor-required return and an unregulated segment that is expected to earn more than the investor-required return. Investors (*i.e.*, the market) would value the gas delivery segment equal to its book value because, at that price, investors would expect to earn exactly the return they require. However, investors would be willing to pay more than book value for the unregulated segment because of its higher-than-required earnings. Thus, the market value of the company as a whole would be bid up beyond its book value until the expected return equals the required return. Mr. Moul's argument suggests that the authorized return on rate base for the regulated gas delivery segment should be increased beyond the required return due to the excess expected earnings of the unregulated segment, which would, in turn, create excess earnings in the regulated gas delivery segment, pushing the market value higher still in a never-ending upward spiral. Staff Ex. 8.0 at 18.

Mr. Moul erroneously argues that if the results of the DCF, which are based on the market price of the companies analyzed, are used to compute the weighted average cost of capital based on a book value capital structure used for rate setting purposes, the utility will not recover its risk-adjusted capital cost because market value capital structures generally reflect less risk than book value capital structures. His argument suggests that when a company's market value exceeds its book value, the risk of a company increases if the capital structure is measured with book values of capital rather than market values of capital. Such a notion is without merit. The intrinsic risk level of a given company does not change simply because the manner in which it is measured has changed. Such an assertion is akin to claiming that the ambient temperature changes when the measurement scale is switched from Fahrenheit to Celsius. Mr. Moul has confused the measurement tool with the object to be measured. Specifically, capital structure ratios are merely indicators of financial risk; they are not sources of financial risk. Financial risk arises from fixed, contractually required debt service payments; changing capital structure ratios from a market value basis to a book value basis does not affect a company's debt service requirements; thus, it does not change the company's risk.

As noted in a corporate finance textbook by Brealey, Myers and Allen, there are a variety of ways to define leverage and there is no law stating how it should be defined. In any case, it is not appropriate to compare book value capital structures with market value capital structures any more than it would be appropriate to compare alternative measures of financial risk. Consequently, when assessing the relative financial risk of Peoples Gas and North Shore to the Delivery Group, Ms. Freetly compared the Companies' FFO interest coverage ratio to the Delivery Groups' FFO interest coverage. She did not compare the Companies' FFO interest coverage ratio to the Delivery Group's RCF to total debt ratio.

Further, the Staff's ratio analysis indicates that both North Shore and Peoples Gas have less financial risk than the Delivery Group. Hence, an upward adjustment to the cost of common equity for the Delivery Group is unwarranted. Staff Ex. 3.0 at 30-32.

Mr. Moul also argued that the Value Line betas cannot be used directly in the CAPM because they are derived based on market value. Hence, he unlevered and relevered the Value Line beta estimates for each of the companies in the Delivery Group for the book value common equity ratios using the Hamada formula. NS Ex. 3.0 at 29. His leverage adjustment is simply wrong because it relies on a comparison of two different measures of financial leverage: book value capital structures and market value capital structures. Staff Ex. 3.0 at 32.

Contrary to Mr. Moul's assertion, it is appropriate for the Commission to apply a market value derived cost of equity to the book value of common equity, even if the Companies' market value differs from its book value. Book value represents the funds a company receives from investors through security issuances on the primary market (*i.e.*, transactions directly between a company and its investors) and reinvestment of earnings. Book value does not adjust to reflect changing investor assessments of the level or riskiness of future cash flow; it only measures how much money the company has invested in assets that serve its customers.

In contrast, the market value is the price investors are willing to pay each other for a security on the secondary market. That is, market value is set by transactions between investors rather than transactions between the company and its investors; therefore the market value of a company's securities has no direct bearing on the amount of funding the company has to invest in assets. Cost of common equity analysis uses market value data because market data continuously adjusts to reflect investor return requirements as they are continuously re-evaluated.

The market value of a stock would grow to exceed its book value only if investors expected to earn a return above their required return. If that is the case, the market value will adjust upward until the expected return once again matches the required return. Thus, the market value always reflects the investor-required return, regardless of the book value. That is why it is appropriate, indeed necessary, to use a market-based cost of common equity for regulatory rate setting. Similarly, book value always represents the funds available to the company to invest in assets serving its customers, regardless of the market value. That is why it is appropriate and necessary to use a book value rate base for regulatory rate setting. The application of the market required return to the book value rate base simply takes the return investors demand to earn from a dollar invested in the common equity of a company, given the amount of risk in the common equity of the company and the current price of risk, and applies it to the number of common equity dollars invested in the rate base of the Companies. Staff Ex. 8.0 at 18-19.

Taken together, eliminating the inappropriate leverage adjustments to his DCF and CAPM estimates would produce a cost of common equity of 9.22% [(9.25% + 9.19%)/2]. Incorporating a more appropriate growth rate estimate in Mr. Moul's DCF analysis produces a cost of common equity of 9.00% [(8.82% + 9.19%)/2]. These corrected costs of equity estimates are significantly lower than the 10.25% he recommends for both Companies and is consistent with Staff's recommendation.

The Commission has properly rejected the use of leverage adjustments in several prior proceedings. Docket Nos. 01-0528/01-0628/01-0629 (Consol.), Order at 12-13 (March 28, 2002); Docket Nos. 99-0120/99-0134 (Consol.), Order at 54 (August 25, 1999); Docket No. 94-0065, Order at 92-93 (January 9, 1995). In fact, Mr. Moul presented, and the Commission rejected, the exact same leverage adjustment, based on the same arguments, in the Companies' 2007 and 2009 rate cases. Docket Nos. 07-0241/07-0242 (Consol.), Order at 95-96; Docket Nos. 09-0166/09-0167 (Consol.), Order at 128-129. The Commission's Order from the 2007 rate case quite clearly sets forth, in great detail, the reasons such a leverage adjustment should be rejected once again in this proceeding:

> In the Commission's judgment, the book value capital structure reflects the amount of capital a utility actually utilizes to finance the acquisition of assets, including those assets used to provide utility service. In establishing the overall or weighted average cost of capital, the proportion of common equity, based on the book value capital structure, is multiplied

> by market-required return on common equity. The Commission has used this approach in establishing utility rates for at least twenty-five years. (e*.g.*, *Ameren Order*, Docket Nos. 06-0070/06-0071/06-0072 (Consol.) *at* 141) ("[t]he Commission observes that it has repeatedly rejected arguments in favor of using market-to-book ratios as the basis for establishing cost of common equity"). Market value is not utilized in this calculation because it typically includes appreciated value (as reflected in its stock price) above the Companies' actual capital investments….
>
> Further, the Companies have failed to establish why a mismatch between the financial risk reflected in the book value and market value capital structures is problematic. If the Companies were correct that regulatory commissions, including this one, have been understating the market-required return on equity for twenty-five years, then the market values of common equity for Companies would not have remained well above the book values during that time. A practice of routinely understating the market-required return on common equity would have surely driven down the market values of common equity to near book value, but that has not happened. Accordingly, the Commission does not agree that an adjustment to the market required return on common equity is necessary to reflect the difference in financial risk between book value and market value capital structures. Therefore, we reject the Companies' financial leverage adjustment to their DCF results and their proposal to impose a similar leveraging adjustment to the betas used in their CAPM analysis.

Docket Nos. 07-0241/0242 (Consol.), Order at 95-96.

<u>CCI's Position</u>

<u>Overview</u>

Mr. Moul proposes a 10.25% cost of common equity for the Companies. The Companies' proposed cost of equity is more than 100 basis points higher than any other expert estimate in the record. Staff's expert Janis Freetly concluded that a 9.05% cost of equity is appropriate. CCI's expert witness, Michael Gorman, recommends a 9.15% cost of common equity. Mr. Gorman's analyses identified that return on equity as fair compensation for the Companies' investment risk and as adequate to preserve the Companies' financial integrity and credit standing. CCI Ex. 1.0 (Gorman) at 2. Mr. Gorman's recommended return satisfies the criteria of the U.S. Supreme Court's hallmark Bluefield Water Works and Hope Natural Gas decisions: 5 returns that are adequate to

(a) maintain financial integrity, (b) attract capital on reasonable terms, and (c) approximate returns on investments in other firms of comparable risk.

Mr. Gorman's risk-based estimate of the Companies' market cost of common equity is reasonable and should be adopted. To avoid excessive rates for the Companies' delivery service customers, the recommendation of the Companies' witness, Mr. Moul must be rejected.

The Companies' Investment Risk

Mr. Gorman began his cost of equity analysis with an assessment of utility industry investment risk, credit standing, and stock price performance. He concluded that "the market continues to embrace the utility industry as a safe-haven investment, and views utility equity and debt investments as low-risk securities." CCI Ex. 1.0 at 5. The market views the Companies similarly, with credit rating agencies characterizing their business risk as "Excellent" and finding their financial risk "Significant," but also noting their cash flow from "low-risk regulated gas distribution operations." CCI Ex. 1.0 at 7-8.

Accurate, risk-based estimates of the Companies' market-required return, as quantified by the DCF and CAPM models relied upon by this Commission, would reflect that unchallenged market perspective. The estimates of Mr. Gorman and Ms. Freetly do so. Mr. Moul's outlier recommended estimate does not.

CCI's Cost of Equity Analyses

To develop his recommended cost of equity estimate, Mr. Gorman performed three versions of the Discounted Cash Flow ("DCF") model analysis, and a Capital Asset Pricing Model ("CAPM") analysis. Because shares in the Companies are not publicly traded, Mr. Gorman's model analyses used a proxy group of publicly traded companies that have investment risk similar to NS-PGL. CCI Ex. 1.0 at 11. With two exceptions, Mr. Gorman's proxy group is the same as the proxy group used by the Companies' witness and Staff. Mr. Gorman omitted two firms because of their involvement in significant merger and acquisition activity, which affects their underlying fundamentals. CCI Ex. 1.0 at 12, 13.

DCF Analyses

For his DCF analyses, Mr. Gorman used distinctive growth inputs to reflect changes in growth expectations across near-term, transition, and long-term periods. The DCF method uses stock price, dividends, and a growth estimate to estimate the market-required return. Mr. Gorman conducted separate constant growth analyses using (i) consensus analysts' growth projections, and (ii) a sustainable growth estimate based on an internal growth methodology, and his third DCF analysis was a multi-stage model that used (iii) near-term, transition, and long-term growth estimate inputs. See CCI Ex. 1.0 at 14-15 and 17-27. The results of Mr. Gorman's DCF models are shown Table 2 of CCI Exhibit 1.0 at 27:

Constant Growth DCF Model (Analysts' Growth)	8.50%
Constant Growth DCF Model (Sustainable Growth)	9.50%
Multi-Stage Growth DCF Model	8.65%

Mr. Gorman concluded that the high end of this range was unreasonable, because the underlying growth rate far exceeded the current consensus of industry analysts and economists, regarding the expected pace of long-term growth in the overall economy. CCI Ex. 1.0 at 27, 43. These forecasts included, for example, projections published by "Blue Chip Financial Forecasts," U.S. EIA in its "Energy Outlook," and the Congressional Budget Office. CCI Ex. 1.0 at 25-27. Mr. Gorman determined that the midpoint of the range of his DCF results represented the best estimate of the Companies' current market cost of equity. CCI Ex. 1.0 at 27.

CAPM Analysis

Mr. Gorman's final analysis used the CAPM method, which estimates the cost of equity by adding a market risk premium, as modified by a measure of firm specific risk (beta), to a risk-free rate. Mr. Gorman conducted his CAPM analysis using Treasury bond returns as the risk-free rate, an average of historical and forward-looking market risk premium estimates, and the proxy group's average *Value Line* beta. The results of this analysis defined a cost of equity range with a midpoint of 9.24% (rounded to 9.25%).

Recommended Return

Mr. Gorman's recommended cost of common equity is 9.15%, the approximate midpoint between his DCF (9.0%) and CAPM (9.25%) estimates. CCI Ex. 1.0 at 33. By comparing the Companies' key credit rating financial ratios at his recommended equity return level (see CCI Ex. 1.0 at 34-36) with established ratings criteria, Mr. Gorman determined that the Companies' financial integrity is maintained. Based on the most recent S&P Financial Ratio Credit Metric Methodology, the Companies have "Excellent" business risk profiles. In addition, the Companies enjoy a "Significant" financial risk profile, which is more favorable than the "Aggressive" profile most Companies have. CCI Ex. 1.0 at 34. In particular, Mr. Gorman's analysis of the key financial benchmark ratios in S&P's credit rating review showed that, at his recommended 9.15% return on equity and using NS-PGL's proposed capital structures, the Companies' financial credit metrics are supportive of their current investment grade utility bond rating. CCI Ex. 1.0 at 36.

The Companies' witness Mr. Moul recommends a 10.25% cost of equity. His analyses produced a cost of equity estimate of that magnitude only by incorporating adjustments and approaches (discussed below) that the Commission has consistently rejected, and which are not consistent with industry norms. Specifically, Mr. Moul's DCF analyses incorporate a leverage adjustment and an unsustainable growth rate. His CAPM analysis incorporates a leverage adjustment into the beta, and it uses an arbitrary market risk premium. In addition, he offers a discredited Risk Premium analysis, which itself incorporates an arbitrary risk premium estimate. See generally CCI Ex. 1.0 at 37-51.

Mr. Moul's DCF analysis results are artificially inflated by a leverage adjustment of 46 basis points. PGL Ex. 3.0, at 25-38. That leverage adjustment has the effect, if not the purpose, of allowing the Companies to earn the Commission-determined equity return on an appreciated stock price paid in secondary markets, rather than on the actual investment used to provide regulated utility service -- viz., the Companies' book value rate base. *See* 220 ILCS 5/9-211 (rates may be set using only investment actually used to provide service). Secondary market transactions consist of stock market transactions among shareholders and provide no incremental investment devoted to utility service.

Moreover, any theoretical basis for the adjustment is dubious. Despite claiming to capture the cost of using a market value (as opposed to book value) capital structure, Mr. Moul acknowledged: “I know of no means to mathematically solve for the 0.46% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value.” PGL Ex. 3.0 at 25-26. As Mr. Gorman observed, even “if those [Mr. Moul’s leverage] arguments had any theoretical validity, they lack a factual basis and are also inconsistent with relevant industry practices.” CCI Ex. 1.0 at 40.

Mathematically, the Companies’ proposed leverage adjustment is the same as applying the unleveraged market required return to an inflated rate base. CCI Ex. 1.0 at 40. That is clearly unlawful, because a regulated utility is allowed its authorized rate of return only on amounts actually used to provide utility service. 220 ILCS 5/9-211. “Market value is not utilized in this calculation because it typically includes appreciated value (as reflected in its stock price) above the Companies’ actual capital investments.” Docket Nos. 07-0241/07-0242 (Consol.), Order at 96; 220 ILCS 5/9-211.

Mr. Moul’s DCF analysis also uses an excessive growth rate (5.25%) that outpaces the expected growth rate of the economy whose demands the Companies serve (4.70%). CCI Ex. 1.0 at 44. “Both practitioners and academics recognize that a long-term sustainable growth rate for use in a DCF model cannot exceed long-term projections of U.S. economic growth.” CCI Ex. 1.0 at 44.

Mr. Moul’s CAPM analysis also incorporates an improper leverage adjustment, applied in that analysis to the Companies’ already (inconsistently) adjusted *Value Line* beta. CCI Ex. 1.0 at 47, 48; CCI Ex. 2.0 at 13: Table 2. The Companies’ CAPM analysis is further corrupted by Mr. Moul’s use of a market risk premium calculated as the average of a flawed historical estimate and a flawed prospective estimate. His historical risk premium selectively averaged historical returns during subjectively determined (and unexplained) periods described as having high or low interest rates. Mr. Moul’s testimony does not provide details underlying the derivation of his projected market premium from unspecified S&P and *Value Line* data.

The Commission has routinely rejected reliance on Risk Premium analyses like that Mr. Moul offered:

> The Commission will not consider the results of the Companies’ Risk Premium model that only the Companies have employed. We have repeatedly rejected this model as a valid basis on which to set return on equity. Our view remains unchanged.

Docket Nos. 09-0166/0167 (Consol.), Order at 128.

Because the Commission has consistently rejected the use of risk premium analyses, the Companies’ Risk Premium analysis and estimate serve only to add a high-end data point, to increase the average of Mr. Moul’s cost of equity estimates. Without this additional estimate, the average of Mr. Moul’s estimates would decline by more than

60 basis points. The analysis also uses an arbitrary risk premium estimate that is not shown to be appropriate for the Companies. CCI Ex. 1.0 at 44.

Notwithstanding the Commission's routine rejection of Risk Premium analyses like that Mr. Moul offered, Mr. Moul criticized Mr. Gorman for not offering one. Although Mr. Gorman rejected this criticism, he also performed a balanced, reasonable risk premium analysis to demonstrate the unreasonableness of Mr. Moul's Risk Premium analysis result. CCI Ex. 2.0 at 1-2. Mr. Gorman's Risk Premium analysis yielded a return on equity range of 8.85%-9.50% with a midpoint of 9.15%. *Id.* at 28. This is substantially below Mr. Moul's Risk Premium equity return estimate of 10.39%. NS-PGL Ex. 19.0 at 25.

Mr. Moul also used the Comparable Earnings approach as a "check" on the results obtained using his other methods. PGL Ex. 3.0 at 3. However, for the reasons Mr. Gorman explains in his testimony, the comparable earnings approach does not accurately measure the required return for the investment risk of the Companies. *See* CCI Ex. 1.0 at 50-51.

Moreover, though Mr. Moul claimed to select companies using parameters that represent similar risk traits for the public utility and the selected comparable risk companies, Mr. Moul purposefully eliminated perhaps the most significant risk trait -- the regulated returns of public Companies. PGL Ex 3.0 at 36. All the companies in Mr. Moul's Comparable Earnings analysis are non-regulated. PGL Ex. 3.0 at 36. As Mr. Gorman noted, the fact that Companies are regulated is a key factor in S&P's rating of the business risk of public utilities as "Excellent." S&P states specifically:

> We view PGLC's business risk profile as excellent, reflecting our assessment of the regulated utility industry risk as 'very low' and a 'very low' country risk because the company's operations are based in the U.S.

CCI Ex. 1.0 at 7.

Furthermore, basing the allowed return for a regulated Illinois utility on a selection of unregulated companies, even as a "check," would violate the spirit, if not the express wording of Section 9-230 of the Illinois Public Utility Act. 220 ILCS 5/9-230. That provision is intended to preclude any distortion of a utility's rate of return by consideration of the risk of an unregulated enterprise -- in particular, affiliates. Although Mr. Moul does not use unregulated companies affiliated with the Companies, the distorting effect of these unregulated entities' business activity risks would affect the allowed return for regulated Companies.

Mr. Gorman recommends that the Commission determine that a 9.15% cost of common equity is reasonable and appropriate for setting the Companies' rates in this proceeding. Staff recommends a lower cost of equity (9.06%) that is comparable to Mr. Gorman's. In stark contrast to the Companies' inflated estimate (more than 100 basis points higher than any other in the record), the CCI and Staff recommended returns are mutually supporting. Eliminating Mr. Moul's inflating adjustments from the Companies' analyses would yield a return on equity in the range of 8.85% to 9.50%. That range encompasses both CCI's and Staff's recommended returns. CCI Ex. 1.0 at 37; Staff Ex.

3.0 at 2. For the reasons discussed, the Commission should adopt the Mr. Gorman's well-supported 9.15% cost of common equity for the Companies.

<u>Commission Analysis and Conclusion</u>

In determining the cost of equity the Commission is required to analyze the values derived from financial analysis tools commonly employed in making this determination. The parties presenting evidence on this issue are the Companies, Staff and CCI. Staff and CCI obtained similar results, the Companies numbers are substantially higher.

DCF analysis is a measure of the value of a company today, based on projections of how much money it's going to make in the future. Essentially the DCF value is the average of the present value of dividends plus a growth estimate for a group of similar companies. Individual analysts use different sources to find what they believe to be appropriate data based upon their backgrounds and experience.

Staff's expert, Ms Freetly, incorporated the dividend yield calculated by the Company expert at 4.00%. She then averaged projected earnings *per* share and dividends *per* share data for similar companies from four reporting sources including the Value Line projection relied upon by the Companies. This produced an average growth factor value of 4.82 %. Combining dividends and average growth projections produced a DCF value of 8.82%

CCI's expert began his cost of equity analysis with an assessment of utility industry investment risk, credit standing, and stock price performance. He concluded that the utility industry continues to be considered a safe-haven investment and that utility equity and debt investments are perceived as low-risk securities.

The CCI expert conducted three separate DCF analyses using: consensus analysts' growth projections, a sustainable growth estimate based on an internal growth methodology, and a multi-stage model that used near-term, transition, and long-term growth estimate inputs. His analysis of dividends and projected growth produced a value of 9.0%

The Companies expert on the other hand used a higher 5.25% growth factor reflecting "improving business conditions." The Commission also notes that this growth factor is higher than the 4.7% growth of the economy as a whole. Mr. Moul, the Companies' expert also used an upward "financial leverage adjustment" conflating book and market values to massage the DCF value in an upward direction. The Company derived DCF value was 9.71%.

The Companies have on many prior occasions attempted to convince the Commission that using a financial leverage adjustment to transform market to book value ratios is appropriate. This technique is produces a higher DCF value. The Commission has repeatedly rejected this manipulation:

> . . . the Commission does not agree that an adjustment to the market required return on common equity is necessary to reflect the difference in financial risk between book value and market value capital structures. Therefore, we reject the Companies' financial leverage adjustment to their DCF results

> and their proposal to impose a similar leveraging adjustment to the betas used in their CAPM analysis.

Docket Nos. 07-0241/0242 (Consol.), Order at 95-96; *See also* Docket Nos. 09-0166/09-0167 (Consol.), Order at 128-129.

CAPM Analysis

Another tool is CAPM analysis. The parties CAPM analysis produced values roughly consistent with their individual DCF results. CAPM determines an expected rate of return on a security by incorporating three variables: a) the risk-free rate of return; b) a "beta" that measures systematic risk; and c) the market risk premium.

For the risk free rate the Companies value was 4.25%, based on its expert's assessment of the midpoint of historical and forecast yields of 20 year treasury bonds. The Companies' inputs, at the very least, minimize the significance of the last several years of substantially lower interest rates that continue to be in effect at this time. For its beta measurement of systematic risk, the Companies employed the average Value Line beta for the Gas Group, "adjusted (upward) to reflect the application of this market-based measurement to the utility's book value capital structure used in ratemaking".

In other words, the two of the Companies' CAPM inputs are derived by selecting only higher interest rates and applying a Commission rejected leverage adjustment technique to the beta measurement. The Company also uses a risk premium value higher than Staff or CCI. Its bottom line CAPM number is 9.62%.

Staff's beta parameter averaged weekly *Value Line* betas with an average of monthly betas from *Zacks* and betas calculated using a regression analysis that the Commission has routinely adopted for the CAPM. These calculations produced a beta for the Delivery Group of 0.64. Staff points out that in the past the Commission has accepted Staff's beta number derived from several sources in order to reduce measurement error that might arise from a single source beta as proposed by the Companies.

For its risk-free rate parameter, Staff's expert, Ms. Freetly, used the 3.66% yield on thirty-year U.S. Treasury bonds on October 31, 2013. For the expected rate of return on the market parameter, Staff used a DCF analysis on the firms composing the S&P 500 Index generating an expected rate of return on the market of 12.43%. Inputting those three parameters into the CAPM, Staff's CAPM estimate of the cost of common equity for the Delivery Group is 9.27%

CCI's CAPM used Treasury bond returns as the risk-free rate, an average of historical and forward-looking market risk premium estimates, and the proxy group's average Value Line beta. The results of this analysis defined a cost of equity range with a midpoint of 9.24% rounded to 9.25%, almost identical to Staff's value.

The Commission finds that Staff's CAPM value of 9.27% is reasonable and supported by the record. The Commission finds that the Companies CAPM value is not appropriate.

Risk Premium Analysis

The Companies also uses a risk premium value that incorporates questionable assumptions. First, the Companies used historical and forecasted yields to estimate that the prospective yield on A rated corporate bonds should be 5.25% rather than the very recently observed rate of 4.54%. Their equity risk premium value of 6.25% represents the spread between common stocks in the S&P 500 and the yield on long term government bonds. Adding the two numbers produces a value of 11.50%.

Staff notes the S&P index is composed largely on non-rate regulated industrial concerns whose required rate of return exceeds the cost of equity for gas Companies. Staff argues against the use of the S&P 500 to estimate the expected return on equity for NS and PGL. The Companies are much lower risk companies than the overall market average. The risk premium for the overall market will be larger than that of an A-rated public utility, like NS and PGL. Therefore, adding that larger risk premium to the base bond return produces an overstated cost of equity estimate. The Companies' Mr. Moul effectively uses a cost of equity estimate for the overall market as an estimate for the lower risk NS and PGL.

Moreover, this Commission has routinely rejected risk premium analysis as a valid basis for determining return on equity. *See e.g.* Docket Nos. 09-0166/09-0167 (Consol.), Order at 128-129.. CCI argues that the Companies only use this Commission rejected technique to add a high-end data point, increasing the average of their cost of equity estimates.

The Companies also argued that comparable earnings of other companies could be used as a measure of required return. Unfortunately, the "comparable" companies used in their analysis don't include any other regulated Companies whose risk profile and earnings are lower than other types of businesses. The Commission finds this a comparison between apples and oranges.

The Commission finds that Staff's revised cost of common equity of 9.05% is reasonable and supported by evidence and analysis. The Commission notes that Staff's bottom line conclusion is supported by CCI's very similar determination, derived using the same methods with different inputs. The Commission rejects the Companies' significantly higher determination based in part on improperly biased input values and analytic tools that the Commission has repeatedly rejected.

F. Weighted Average Cost of Capital

Commission Analysis and Conclusion

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 incorporating Staff's recommended capital structure and costs of short-term debt, long-term debt, and common equity, equals 6.26% for North Shore and 6.56% for Peoples Gas. The record consistently demonstrates that Staff's recommendations are based on valid application of sound financial theory, while the higher recommendations of the Companies are not.

North Shore Gas Company				
		Percent of		Weighted
	Amount	Total Capital	Cost	Cost
Long-term Debt	$79,784,000	38.94%	4.13%	1.61%
Short-term Debt	$21,678,000	10.58%	0.74%	0.08%
Common Equity	$103,435,000	50.48%	9.05%	4.57%
Total Capital	$204,897,000	100.00%		
Weighted Average Cost of Capital				**6.26%**

The Peoples Gas Light and Coke Company				
		Percent of		Weighted
	Amount	Total Capital	Cost	Cost
Long-term Debt	$864,589,000	46.51%	4.26%	1.98%
Short-term Debt	$58,805,000	3.16%	0.91%	0.03%
Common Equity	$935,610,000	50.33%	9.05%	4.55%
Total Capital	$1,859,004,000	100.00%		
Weighted Average Cost of Capital				**6.56%**

VII. OPERATIONS

A. AMRP Main Ranking Index and AG-Proposed Leak Metric(s)

Peoples Gas' Position

Peoples Gas states that the evidence establishes that: (1) Peoples Gas prudently uses its MRI to make decisions about which mains to replace; (2) the "peer group" analyses presented by AG witness Dr. Dismukes relating to replacement trends and leak trends are flawed; and (3) Dr. Dismukes' vague proposals to add one or more "performance metrics" related to leaks as conditions of recovery of costs of efforts to reduce leaks are not only unnecessary, but they could be counter-productive by diverting resources away from their best use.

Peoples Gas witness, David Lazzaro, an experienced engineer in replacing cast iron and ductile iron mains, explained that Peoples Gas utilizes criteria according to its MRI, which guides it in making appropriate decisions about targeting which mains to replace. Mr. Lazzaro discussed in detail the development and use of the MRI. He also described the processes for management oversight of the AMRP and coordinating with the City of Chicago.

Peoples Gas states that AG witness Dr. Dismukes suggested that one or more additional metrics related to leaks be adopted for the AMRP, but his proposals were vague and ill-conceived (not an accurate measure of the effectiveness of the AMRP), unnecessary given the current leak control measures in place, and, if adopted, could be counter-productive. Companies witness Mr. Lazzaro, in his rebuttal testimony, explained in detail why Dr. Dismukes' original proposal, of new metrics related to corrosion related leaks, was poorly designed and unnecessary, and why the MRI is what should continue to be used. Companies witness Mr. Lazzaro, in his surrebuttal testimony, explained in detail why Dr. Dismukes' vague rebuttal proposal, of new metrics related to a broader range of leaks, also was poorly designed and unnecessary, and why the MRI is what should continue to be used.

Peoples Gas states that adding new metrics, as AG witness Dr. Dismukes proposed, simply is a bad idea. As Companies witness Mr. Lazzaro explained:

> Q I mean, let's put it simply: Why don't you want to add those metrics as metrics for the program?
>
> A Well, we have currently in place procedures that grade and monitor the leaks that we have in our system, the ICC safety staff is aware of these pipeline safety staff is aware of these procedures and they audit the process annually, and opposed to any metrics that would take away the resources whether they're staff or dollars to focus on something that I don't think would help us with our replacement, considering we have the Main Replacement Program already.

Tr. at 130.

Peoples Gas states that the AG acknowledges that it has no objection in principle to Peoples Gas using the MRI. Further, the AG and its witness failed to identify anything in the MRI to which they object.

Peoples Gas contends that the AG's arguments in its briefs are devoted mostly to defending Dr. Dismukes' analyses, but provide essentially no factual support for his or the AG's vague proposals. The evidence does not provide any credible basis for rejecting the testimony of the Mr. Lazzaro, an experienced engineer, in favor of that of Dr. Dismukes, an economist, regarding whether new metrics should be adopted. Peoples Gas argues that the AG and Dr. Dismukes refer to cost recovery-related proposals adopted in three cases in New Jersey, but do not appear to advocate those same exact proposals here, do not show that circumstances are similar here, and provide no evidence that those proposals would be suitable, or cost-effective, as to Peoples Gas.

Peoples Gas concludes that the AG's vague proposals on this subject are ill advised and should not be adopted.

AG's Position

The AG explains that AG witness Mr. Dismukes prepared a series of analyses that examine Peoples Gas' historic pipeline replacement and leak trends, as well as a comparison of those trends to the midwestern LDC peer group. The purpose of Mr. Dismukes's leak analysis is to examine how effective, from an empirical perspective, Peoples Gas has been in replacing leak-prone or "priority" mains and services, as well as in reducing its corrosion-related leaks under its AMRP. His analysis expands upon the statistics discussed by PGL witness Lazzaro in his direct testimony. Mr. Dismukes' analysis of Peoples Gas' replacement and leak trends spans a relatively long time period, and includes the years in which Peoples Gas did not have an infrastructure replacement cost recovery mechanism, the years in which Rider ICR was in place, as well as those years after Rider ICR was reversed through a court appeal. Mr. Dismukes utilized data taken from PGL's annual reports filed with the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("PHMSA"), Office of Pipeline Safety ("OPS").

The AG states that the share of mains composed of cast iron fell by a few percentage points from 2009 to 2013, even as PGL's leaks have been rising over that time span.

Looking at historical replacement rates of leak-prone mains, Mr. Dismukes found that Peoples Gas' replacement rate of leak-prone main has decreased since 1991, on a relative basis. In fact, Peoples Gas' replacement rate reached its lowest relative level during the period 2009-2011, being 88 percent less than the replacement rate observed almost twenty years earlier. Meanwhile, midwestern LDCs, after an up-and-down trend (relative to 1991 levels) over the past two decades, have been replacing priority mains over the past two years at rates that are over 1.5 times their 1991 levels. Peoples Gas, on the other hand, while increasing its relative replacement rates over the past two years, has not done so at levels comparable to regional Companies.

Mr. Dismukes also found that, while a peer group of midwestern LDCs has attained a leak rate due to corrosion of around 50% or 60% of 1991 levels for the past decade-plus consistently, PGL's leak rate due to corrosion has been consistently (except for 2011) above the 1991 leak rate for the past seven years. Corrosion-related leaks are currently at levels that are 79 percent higher than those reported by Peoples Gas, on average, during the 1999-2006 period.

Mr. Dismukes recommended in direct testimony that given PGL's poor recent performance on reducing corrosion-related leaks, the Commission should consider adopting additional performance metrics that examine Peoples Gas' trends in reducing corrosion related leaks. Mr. Dismukes also pointed to several proceedings in the New Jersey Board of Public utilities ("NJBPU") wherein the NJBPU adopted leak performance metrics tied to a utility's allowed rates of return on infrastructure investment "trackers" or riders or tied the metrics to the allowance of recovery for the utility's leak-reduction efforts.

The AG submits that in rebuttal testimony, PGL witness Lazzaro argued that Mr. Dismukes should have addressed leaks with the seven other PHMSA leak cause codes (Natural Forces; Excavation Damage; Other Outside Force Damage; Material / Welds; Equipment; Incorrect Operations; Other). Mr. Lazzaro argued that following the new PHMSA regulations on Distribution Integrity Management Programs ("DIMP") issued in 2010 and enforced in 2011, Peoples Gas re-categorized many of its leaks as Corrosion related. Mr. Lazzaro did not explain, however, why the DIMP rule would not have affected other midwestern Companies similarly or why the increase in Corrosion-related leaks that Mr. Dismukes found began in 2007. Mr. Lazzaro argued that any performance metric for the AMRP should also consider Natural Forces- and Other-related leaks. He also argued that the MRI already used by Peoples Gas for prioritizing main replacements takes these three cause codes into account.

Mr. Dismukes expanded his leak analyses in his rebuttal testimony to consider the two additional PHMSA leak cause codes mentioned by Mr. Lazzaro. AG Exhibit 8.5 shows the results of his analysis on Natural Forces-related leaks, which increased substantially for PGL relative to peers from 2005, the first year data was collected for this leak category, through 2008. This category of leaks then began to decline for PGL until 2012, but then increased in 2013 to a level higher than any previous year. Meanwhile, the peer midwestern companies have consistently had leaks at similar levels since 2005.

AG Exhibit 8.6 shows the result of Mr. Dismukes' analysis on Other-classified leaks, which showed that PGL's Other leaks were relatively high in the 1990s, then dropped considerably in 1999 and 2000 and continued to decline since 2001, with a slight increase in 2013. This trend is similar to that of the regional Companies. The AG states that there is no evidence that leaks in the Natural Forces or Other categories were suddenly re-classified to the Corrosion category from 2011 onward.

The AG continues that there is no reason to think that the possible change in PHMSA reporting in 2011 had any material impact on Peoples Gas' overall leak trends, which Mr Dismukes found were still upward in recent years. AG Exhibit 8.7 shows Mr. Dismukes' study of a composite of Corrosion, Natural Forces, and Other leaks over 1991-2013. Peoples Gas' leaks across these three categories were relatively high in the 1990s, dropping significantly in 1998 and staying at similar levels until 2007 and 2008, when the Company experienced a significant relative increase in its composite leaks. The regional Companies also had relatively high leaks until 1997, when relative composite leaks started to decline and have remained fairly constant until 2009, when they again started to decline on a relative basis.

While the AG does not object in principle to PGL's use of its MRI, the Dismukes proposal goes beyond PGL's private, voluntary use of the MRI and requests that the Commission implement performance metrics that would be used as a basis for denying or allowing recovery of expense for leak reduction efforts, similar to the NJBPU case discussed at page 21 of Mr. Dismukes' direct testimony. The AG submits that the Commission could set performance metrics for leak reductions based on the recent trends observed in the midwestern peer group (for example, Peoples could be required to reduce its leaks with all three of the aforementioned cause codes to 50% of 1991 levels, as the peer group average has done for the past several years, as shown in AG Exhibit 8.7) and deny cost recovery for those leak reduction efforts to the extent that Peoples fails to meet the targets.

Commission Analysis and Conclusion

The Commission agrees with Peoples Gas and finds that the record does not support imposing any additional metrics on Peoples Gas' main replacement program, whether for operational purposes or as conditions of recovery of costs of leak reduction efforts. Peoples Gas provided evidence from an experienced engineer supporting the continued use of its MRI. The Commission finds that the evidence does not support the AG's proposals for new metrics and that their adoption would not prove useful and cost-effective enough for the Commission to impose them.

B. Pipeline Safety-Related Training (Uncontested)

The Companies and Staff agree that this Order should include a Findings and Ordering Paragraphs' paragraph that specifies, for Peoples Gas, the test year amounts of certain pipeline-safety related training. The agreed language is as follows:

> (x) The test year amounts of test year pipelines safety-related training for Peoples Gas are: $11,355 for Corrosion-NACE Levels 1 and 2 Certification; $80,500 for 49 CFR Parts 191 and 192 Training; $0 for Construction Inspection; $6,300 for all other pipeline safety-related training, totaling $98,135.

The agreed language is proper and it is incorporated in the Findings and Ordering Paragraphs section of this Order.

VIII. COST OF SERVICE

A. Overview

The Companies prepared embedded cost of service ("ECOS") studies to develop and implement their rate design proposals. With few exceptions, the Companies' ECOS studies are substantially identical to those presented, and approved by the Commission, in the Companies' recent rate cases. They slightly modified how they allocated Uncollectible Expense and the Miscellaneous Revenues in Account 495.

Staff states that the Companies' ECOS studies identify the revenues, costs, and profitability for each class of service and are a partial basis for the Companies' proposed rate design. Generally, the Companies prepared the ECOS studies utilizing three major steps: (1) cost functionalization; (2) cost classification; and (3) cost allocation of all the costs of the utility's system to customer classes. Staff witness Johnson testified that he had no objection to the Companies' proposed ECOS studies to assign costs to the various functions and rate classes.

AG/ELPC witness Scott Rubin recommended the Commission use the results of the Companies' ECOS studies as a guide to the allocation of costs among the customer classes and that the results of those studies should be used as a guide to designing rates.

IIEC witness Brian Collins takes issue with the Companies' proposed ECOS studies and proposes various adjustments.

B. Embedded Cost of Service Study

1. Allocation of Demand-Classified Transmission and Distribution Costs

<u>Companies' Position</u>

The Companies proposed to allocate demand-classified transmission and distribution ("T&D") costs using an average and peak ("A&P") methodology. The Companies assert that A&P is an accepted approach to such T&D cost allocation, and it is consistent with the Commission's orders in the Companies' five most recent rate cases. IIEC proposed a coincident peak ("CP") allocator for demand-classified T&D costs. Staff opposed IIEC's proposal and supported the A&P methodology. AG/ELPC opposed IIEC's proposal.

The Companies noted that IIEC is correct that they have supported a CP allocator for demand-classified T&D investment in past cases. However, the Companies explained that, in Docket Nos. 07-0241/07-0242 (Consol.), the Commission rejected that approach after considering arguments from the Companies and others supporting a CP allocator.

The Commission concluded that the Companies had not "overcome the Commission-established and long-standing tradition of A&P methodology for allocating distribution costs." Docket Nos. 07-0241/07-0242 (Consol.), Order at 199; also see NS-PGL Ex. 28.0 at 4. Subsequent to that case, to limit the scope of contested issues, the Companies have used the A&P allocator. The Companies further explained that the A&P allocator is recognized as an acceptable methodology for demand-classified costs. For example, the NARUC states at pages 27-28 of its Gas Distribution Rate Design Manual (June 1989) that the A&P demand allocation method is a commonly used demand allocator for natural gas distribution Companies and that this method tempers the apportionment of costs between the high and low load factor customers.

Staff's Position

Staff argues that the Commission should accept the Companies' proposed ECOS studies. These ECOS studies use largely the same cost allocation methodologies that were approved in the Companies' 2009, 2011, and 2012 rate cases. They are acceptable guidance for determining rates in this case.

Staff acknowledges that IIEC witness Collins disagrees with the Companies' proposed A&P cost allocation methodology for allocating T&D mains. He instead proposes that the CP cost allocation methodology be used. Mr. Collins provides two reasons why the A&P cost allocation method should be rejected. First, he states that the A&P cost allocation method double counts the "average" component of demand. Second, he opines that the A&P cost allocation method does not appropriately reflect how costs are incurred by the Companies.

Staff details that Companies Witness Hoffman Malueg explained that the Companies have been using the A&P allocation methodology since Docket No. 07-0241/07-0242 (Consol.). She also stated that while IIEC witness Collins continually asserts that the Companies' T&D system is designed to meet peak day demand, the Companies explained repeatedly in data responses to the IIEC that peak day demand, while being the primary factor, is not the only factor the Companies consider when designing the system. With respect to Mr. Collins' contention that the A&P allocator is double counting, Ms. Hoffman Malueg disagrees with this concept and states that demand costs are attributable to both average use as well as peak demand. To align with this theory, the A&P demand allocation method mathematically combines average usage and peak demand to appropriately allocate capacity costs based upon that cost causation method. Ms. Hoffman Malueg further explains that the A&P demand allocation method also mathematically weights the portion of the allocator that is to be based upon average demand by the system load factor, further aligning the theory that it is premised upon.

Staff witness Johnson explained that Mr. Collins' argument fails to recognize that the A&P allocator serves two distinct purposes, to reflect class contributions to the system average and to the system peak. Accordingly, the A&P appropriately considers both average and peak demands in the allocation process.

Staff continues that the Commission addressed this double counting argument by the IIEC in Docket No. 04-0476, Illinois Power Company's proposed general increase in natural gas rates. The Commission concluded that:

> While the IIEC argues that the A&P method improperly double counts average demand in allocating T&D plant costs, the Commission believes that when allocating T&D plant costs an emphasis on average demand is appropriate. The record demonstrates that the A&P method relies upon class average demands and class coincident peak demands, which by definition are numerically larger than the associated averages.

Illinois Power Company, Docket No. 04-0476, Order at 64-65 (May 17, 2005).

Additionally, in Central Illinois Public Service ("CIPS") and Union Electric ("UE") proposed general increase in natural gas rates, the Commission stated:

> Furthermore, the Commission finds that the argument that the A&P method double counts average demand is not a sufficient basis for rejecting that approach. In fact, the Commission believes that when allocating demand costs it is the A&P method's emphasis on average costs rather than peak costs that justifies its adoption.

Central Illinois Public Service Company (AmerenCIPS) and Union Electric Company (AmerenUE), Docket Nos. 02-0798/03-0008/03-0009 (Consol.), Order at 98 (October 22, 2003).

In response to Mr. Collins' argument that the A&P cost allocation method does not appropriately reflect how costs are incurred by the Companies, Mr. Johnson explained that the A&P allocates costs by both peak demands and average demands. The peak demand component recognizes that a T&D system is sized to meet maximum annual demands. However, there is also an average demand component because meeting peak demands is not the sole factor that shapes investment in a T&D system. Another factor, but not the only factor, is the economic motivation to construct a T&D system. This is more appropriately reflected by average demands than peak demands. This is because year-round demands are necessary to generate sufficient revenues to justify investment in a T&D system. These year-round demands are reflected in the average demand but not the peak demand portion of the A&P allocator.

Staff adds that other factors are safety and reliability. Safety and reliability investments are more appropriately reflected in average demands. Safety and reliability are important, not just only for the peak day, but for every day of the year that gas is consumed which is what the average demand component reflects.

Staff notes additionally that there is strong precedent in Illinois for using the A&P demand allocator. The Commission typically uses this allocation methodology for the distribution costs of gas companies. In CIPS and UE's proposed general increase in natural gas rates, Docket No. 04-0476, the Commission concluded:

> The allocation method that properly weights peak demand is the A&P method, the same method that the Commission adopted in CIPS' and UE's last gas rate cases. The A&P method properly emphasizes the average component to reflect the role of year-round demands in shaping transmission and distribution investments.

Docket Nos. 02-0798/03-0008/03-0009 (Consol.), Order at 98.

Staff states that the Commission also accepted the use of the A&P allocation methodology in Nicor Gas' 2004 rate case. *Northern Illinois Gas Company*, Docket No. 04-0779, Order at 102 (September 20, 2005) and Nicor Gas' most recent rate case Docket No. 08-0363. The Commission subsequently directed Peoples Gas and North Shore to employ the A&P demand allocation methodology to allocate the distribution costs in Docket Nos. 07-0241/07-0242 (Consol.). Docket Nos. 07-0241/07-0242 (Consol.), Order at 199. Since then, the Companies have employed the A&P demand allocation methodology in their COS studies. In each case, the A&P methodology was approved by the Commission.

Staff notes that AG/ELPC witness Rubin also disagrees with IIEC's proposal to eliminate the A&P allocator. Mr. Rubin indicated his understanding that the Commission has used the A&P method consistently for the Companies since at least 2007, and IIEC witness Collins does not present any new arguments or a compelling reason to change this well-established allocation method. Mr. Rubin also reviewed the rebuttal testimony of Companies' witness Hoffman Malueg and agrees with her criticisms of Mr. Collins' testimony on this issue and concluded that IIEC failed to show that the Companies' use of the average and peak method is improper.

<u>IIEC's Position</u>

IIEC argues that the ECOS studies proposed by the Companies are flawed because they allocate the demand classified T&D costs (both rate base and expenses) using the A&P allocation method which allocates costs in part by using a volumetric allocation factor (average demand) and fails to recognize a customer component for any portions of its main costs. The Companies support their choice of the A&P method not because it is superior or more respected than the CP method; rather, the Companies use the A&P method in hopes to limit the contested issues in this proceeding. IIEC notes too that the Companies have previously recommended that capacity related T&D system costs be allocated using the CP method in Docket Nos. 07-0241/07-0242 (Consol.). Docket Nos. 07-0241/07-0242 (Consol.), Order at 199. IIEC asserts that the Companies have not presented any technical evidence that supports the use of the A&P method for allocating the Companies' capacity related T&D system costs.

IIEC argues that although the Commission has previously approved the A&P method for the Companies, the Commission has also approved the use of the CP method for allocating capacity or demand related T&D costs in previous Companies' rate cases, notably Docket No. 90-0007 and Docket No. 91-0586. In fact, the Commission Staff supported the CP allocation method in Docket No. 90-0007. IIEC maintains that because the Commission and its Staff have previously shown support for allocating demand related T&D costs on the CP method, there is no clear precedent for the A&P cost allocation method. Determining whether a cost allocation method is appropriate should be based on the evidentiary record in the instant proceeding. While it is true that this Commission has previously approved the use of the A&P method, the Commission is not bound by its prior determinations assuming there is sufficient evidence in the record to support the adoption of a new position, or in this case an old position, by the Commission. *Mississippi River Fuel Corp. v. Commerce Comm'n*, 1 Ill. 2d 509, 116 N.E. 2d 394, 396-397 (1953). IIEC asserts that the record in the instant proceeding provides information not previously available to the Commission in prior rate cases when determining the appropriateness of the CP cost allocation method for the Companies' systems. IIEC states that the evidentiary record in the instant proceeding supports the use of the CP method for allocating T&D system capacity or demand costs. The CP allocator matches the classes' system peak capacity required on the system peak day with the costs incurred by the Company to meet those classes' peak day demands, thus best reflecting cost causation.

IIEC states that the record contains: (1) a detailed explanation and illustration of how the A&P double counts average demand and the resulting detrimental effects to both residential non-heating and large volume users; (2) an illustration of how the A&P allocation factors result in unbalanced cost allocation to the classes; and (3) an illustration of how the A&P allocation factors, when applied to the Companies' system peak day capacity, result in capacity shortfalls for certain classes.

First, IIEC states that a significant issue with the A&P demand allocator is the fact that it double counts the "average" component of demand. Average Demand is counted twice in the allocation of demand costs, once in the coincident peak allocation and then again in the average demand allocation. The double counting results in an over-allocation of costs to higher load factor customers such as residential non-heating customers and industrial customers.

IIEC explains that there are two steps in the process of calculating the A&P factors for the customer classes. The first step determines the average demand component. The second step determines each class's contribution to the system's peak demand. It is in the second step where the double counting takes place. Double counting occurs because the A&P method considers both the average demand and the entire peak demand, which also includes average demand.

IIEC states that because class average demand constitutes a larger percentage of the coincident demand for high load factor customers it adversely affects the S.C. 4 class more than any other class. For PGL, class average demand constitutes 34% of coincident demand for the S.C. 4 class, versus 23% or less for the other classes. For NS, class average demand constitutes 60% of the coincident demand for the S.C. 4 class, versus 23% or less for the other classes.

IIEC continues that the A&P method double counts the service classes' contributions to average demand, and the Companies' method in this case is no exception. Ms. Hoffman Malueg argues that simply because average demand values are smaller than coincident peak demand values that should not imply that the Average and Peak demand allocation method should be discredited because it is 'double counting'.

IIEC responds that Mr. Collins does not argue that average demand is double counted because average demand is smaller than coincident peak demand. Mr. Collins argues that average demand is double counted by the A&P cost allocation formula because average demand is a subset of demand contained within coincident peak demand.

Average demand is a subset of coincident peak demand, where Coincident Peak Demand can be expressed as Coincident Peak Demand = (Average Demand + Peak Demand in Excess of Average). Said simply, the A&P cost allocation formula double counts average demand because average demand is weighted by the system load factor, and then weighted again by (1 - the system load factor) because Average Demand is a subset of Coincident Peak Demand. By using the A&P demand allocation methodology to allocate capacity costs to customer classes, average demand is always given 100% weight in the capacity allocation factor regardless of the system load factor.

IIEC adds that average demand is given considerably more weight in the allocation of T&D capacity cost than are coincident peak demands, which are the primary load characteristic that explains cost causation. The result of double counting Average Demand is that Average Demand will always be given 100% weight in the A&P demand allocation formula despite the fact that Average Demand is not considered in the design of the Companies T&D system capacity. It is peak demand in excess of average that drives the capacity of the T&D systems needed to meet the coincident peak day demands of the Companies' customers. IIEC argues that the CP method is appropriate because it reflects how the T&D system is designed and therefore reflects cost causation.

Second, IIEC maintains that coincident demand best reflects cost causation. IIEC explains that Gas distribution T&D systems are designed based on the design day demand or the coincident peak demand requirements of its customers. The design of the system allows the Companies to offer firm uninterrupted service to all customers every day of the year, including the day the system peak day demand occurs. IIEC asserts that average demand is not a factor in the design of the system as confirmed by the Companies in their response to IIEC Data Requests 6.01 and 6.12. If the Companies designed their systems based on average day demands then it would not be guaranteed the Companies would have adequate capacity to meet the customers' coincident demands on the system peak day.

IIEC continues that while average demand is certainly a factor considered in identifying the variable cost of operating the system, the actual physical size of the T&D mains, compressors, and related equipment is based on customers' contributions to the system peak day demand. Further, average demands do not describe the main size or system capacity that is necessary to provide firm uninterruptible supply of service to all customers every day of the year. The system's capacity must be sized for peak day demand, assuring all customers utilization of their entitlement to that capacity to receive firm, uninterrupted, supply of gas every day of the year, including the day of the peak demand.

Based upon this, IIEC argues that the Companies' proposal fails to meet the cost of service principle of cost causation. The Companies state the most important principle underlying an ECOS study is that cost incurrence should follow cost causation. Therefore, according to the IIEC, the A&P method is inappropriate for ratemaking in this proceeding because it does not appropriately reflect how the costs associated with T&D mains, including both rate base and expenses, are incurred by the Companies. As a result, the A&P allocation method creates an unbalanced allocation of T&D costs among customer classes.

As an illustration of such unbalanced cost allocation resulting from the A&P method, IIEC witness Collins focused on distribution main costs. Distribution main capacity allows customers that need firm service to receive firm service every day of the year, including the day of peak demand. As such, customers need an amount of capacity entitlement equal to their coincident peak day demand that allows them to receive firm service every day of the year. IIEC adds that the actual usage of this capacity entitlement throughout the year then is a function of the customers' load factor.

IIEC explains that the A&P method assigns a significantly different distribution main net plant cost per unit of coincident demand to each customer class, even though all classes have equal rights to firm distribution capacity on the system peak demand day. The per unit cost for distribution main net plant is significantly higher for the Companies' higher load factor customers, specifically the Non-Heating S.C. 1 Residential and S.C. 4 Large Volume Demand Service, than it is for low load factor customers. IIEC argues that under the A&P allocation method, customer classes that more efficiently utilize the T&D system are allocated a premium, on a per unit of coincident demand basis, for distribution main net plant in their rates as compared to lower load factor customer classes.

IIEC states that the above illustration also demonstrates the tempering that Ms. Hoffman Malueg refers to when she explains that the A&P demand cost allocation methodology provides "compromise" and "tempers" cost apportionment between high load factor and low load factor customers. Such temperament allocates a higher per unit cost for distribution main net plant to the high load factor customers than it does the low load factor customers. IIEC maintains that the A&P method misassigns cost to the high load factor customers that should be assigned to low load factor customers under proper cost-causation principles. However, when costs are assigned to the classes using the CP method, all classes are allocated the same per unit cost of distribution main net plant, resulting in a balanced allocation of costs.

IIEC submits that with the A&P cost allocation method, costs are shifted between classes based on load factor, or how they utilize the system peak day capacity. By introducing load factor and volume into the cost allocation process, the A&P method results in rate impact mitigation by misallocating costs in the cost allocation process. IIEC argues that rate impact mitigation should not occur in an ECOS study. A proper ECOS study should properly measure each class's cost causation. The CP method measures costs appropriately because it is based on cost causation. After costs are allocated to classes using a proper ECOS study, rate impact mitigation is then best addressed through revenue allocation and rate design.

IIEC offers that another illustration of how the A&P allocation method does not properly allocate T&D main capacity costs across customer classes is to compare the A&P allocation of the total system peak day capacity to each class, with the amount of actual capacity that is needed by each class on the coincident peak day. The illustration shows the residential non-heating and Large Volume Demand classes are over allocated system capacity using the A&P allocation method. As a result, the Non-Heating S.C. 1 Residential and S.C. 4 Large Volume Demand customers subsidize the cost of capacity to other classes that have a shortfall in capacity needed on the Companies' system to meet their peak day demand requirements. However, when system peak day capacity is allocated to classes based on the CP method, all classes are allocated enough system peak day capacity to meet their coincident peak day demands. IIEC states that in the case of PGL, use of the A&P allocator allocates 11% more capacity to the Non-Heating S.C. 1 Residential class and the S.C. 4 Large Volume Demand Service class than is necessary to meet their peak day demands. In the case of NS, use of the A&P allocator allocates 8.8% to the Non-Heating S.C. 1 Residential class and 34.6% to the S.C. 4 Large Volume Demand Service, again in excess of what is necessary to meet their peak day demands.

Third, IIEC states that a proper cost allocation method should reflect how costs are actually incurred on the Companies' T&D systems. IIEC argues that a utility's selection of a particular cost allocation method should be based on whether that allocation method appropriately reflects class cost causation and results in rates that provide accurate price signals to its customers.

IIEC emphasizes that the most important principle underlying an ECOS study is that cost incurrence should follow cost causation. Because rates should reflect cost causation, the costs used in setting rates should be allocated to classes based on how the classes cause the costs to be incurred by the Companies. IIEC asserts that the cost allocation method should be consistent with cost causation.

IIEC maintains that T&D systems are designed to meet the demands of customers and not their gas throughputs or usages; therefore, allocating the costs of the T&D system based on demand is appropriate. Further, a utility's T&D main investments must meet its customers' demands and a utility incurs the cost to construct and operate T&D mains to meet its customers' peak day demands. This is exactly why IIEC witness Collins believes the CP method is an appropriate cost allocation method for allocating T&D related capital costs and expenses, because the CP method allocates costs based on how they are incurred, using customer peak demands and not annual throughput.

IIEC states further that allocating costs based on how they are incurred is consistent with the NARUC Gas Distribution Rate Design Manual (June 1989) which states at page 20:

> Historic or embedded cost of service studies attempt to apportion total costs to the various customer classes in a manner consistent with the incurrence of those costs. This apportionment must be based on the fashion in which the utility's system, facilities and personnel operate to provide the service.

IIEC Ex. 1.0 at 15-16.

NARUC recognizes that demand or capacity related costs can be allocated to classes based on two factors: (i) peak day demands, and (ii) the number of customers.

The NARUC Gas Distribution Rate Design Manual states the following at pages 23 and 24:

> Demand or capacity costs vary with the size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of the distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.

Id. at 16.

IIEC notes that the Companies cite the NARUC Manual as well in support for their use of the A&P method stating the Manual finds the Companies' allocation method provides compromise and tempers cost apportionment. But the Companies fail to cite further support in the Manual for their use of the allocation method while IIEC states that it cites language from the Manual supporting its position on use of an allocation factor that accurately reflects cost causation. IIEC argues while the Companies' proposed A&P method is one found and used in the Manual, their additional support for its use is tepid at best.

IIEC contends that it is the peak day demand which drives the costs incurred in order to design, construct, implement and maintain a T&D system that is adequate to provide firm service throughout the year, including the peak day, to all customers that want firm service. T&D systems are sized based on peak day demands to ensure that firm gas supply can be delivered every day of the year and because cost causation is driven by peak demand, T&D related costs should be allocated based on peak demand. IIEC claims that as the NARUC manual correctly observes demand and capacity costs vary with the size of plant and equipment and do not vary with annual usage. Therefore, they should not be allocated on the basis of a method that considers average demand or volume.

IIEC states that if the T&D system can meet the peak day demand of its customers it stands to reason it can meet the demand of its customers on every single day of the year. The only way daily needs can be met is through a system that is designed to meet the peak day demand. If the peak day demand can be met, all daily demands will be met as well.

IIEC states that in Docket Nos. 07-0241/07-0242 (Consol.), the Companies advocated for the use of the CP method to allocate T&D mains to customer classes. The Companies' witness Ronald J. Amen found the CP method to be the most appropriate indicator of cost causation and argued against the use of the A&P method.

IIEC argues that using the A&P allocation method to allocate capacity related costs based on perceived benefits resulting from year round use of the Companies' T&D

systems is not based on cost causative factors. Benefits are in the eye of the beholder as there are not objective measures to define or determine to what extent particular customers derived such benefits. In stark contrast, cost-causation is based on the T&D system's engineering and an understanding of the drivers that determine a utility's costs. IIEC concludes that the Coincident Demand allocation method best represents cost causation on the Companies' T&D systems.

Commission Analysis and Conclusion

The Commission agrees with the Utilities and finds that although both the CP and the A&P method are acceptable ways to allocate demand-classified T&D costs, the A&P method of cost allocation is supported by the record and consistent with the method of allocation adopted in previous rate cases. The Commission holds that IIEC has not shown that the CP method is preferable in this case. The Commission finds that the Utilities' use of the A&P method for demand-classified T&D costs is reasonable and is approved.

2. Allocation of Small Diameter Main Service Costs

Companies' Position

The Companies assert that they do not delineate between small and large diameter distribution mains in their ECOS studies, nor is it appropriate to do so. The Companies explained, and it is undisputed, that all of the Companies' customers take service from all the various sized mains in the system. Specifically, except for Peoples Gas' negotiated contract rates (S.C. Nos. 5, Contract Service for Electric Generation, and 7, Contract Service to Prevent Bypass), all service classifications take service directly from mains smaller than four inches and from mains that are four inches and larger. Moreover, the Companies stated that they operate their systems in an integrated manner, which enhances system reliability for all customers. The Companies explained that their ECOS studies have a class-based structure. That is, the Companies allocate costs to the customer classes and not individual customers or *ad hoc* groups within the classes. For the Companies, the customer classes are the service classifications and rate groups within the service classifications for which the Companies design rates.

The Companies state that IIEC's proposal to consider moving the three customers taking service directly from smaller diameter mains to another service class is flawed because these customers do not qualify for S.C. No. 2, which is available only to customers using a monthly average of 41,000 therms or less. None of the three customers are eligible for S.C. No. 2 and all are properly on S.C. No. 4.

The Companies' witness Ms. Hoffman Malueg explained that selectively allocating only certain main costs to S.C. No. 4 is incompatible with the class-based nature of the ECOS studies. The Companies' ECOS studies allocate costs to the customer classes (S.C. No. 4 is such a class), based on class characteristics and not based on individual customer characteristics or *ad hoc* group characteristics within the classes. The number of customers taking service from various main sizes in a given class is irrelevant. Ms. Hoffman Malueg explained that the ECOS studies are not intended to extract for or allocate specific costs to individual customers.

The Companies claim that they do not allocate distribution mains to customer classes within their ECOS studies based on customer counts. The fact that there are only three S.C. No. 4 customers out of 180 (total within both Companies) taking service directly from a main smaller than four inches has no relevance in the ECOS studies. They argue that IIEC apparently seeks only to look at customer counts as relevant for S.C. No. 4 for certain mains, but, if customer counts are appropriate for S.C. No. 4 and for certain size mains, does fairness dictate that customer counts become a factor for all size mains and other facilities, for all service classifications? The Companies state that making a single, selective exception to the class-based nature of the ECOS studies may be feasible, but it is not feasible to begin making exceptions for all particular costs that may fit IIEC's theory.

Staff's Position

Staff explains that IIEC witness Brian Collins proposes to delineate the costs of mains smaller than 4 inches and allocate those costs to all classes except for the S.C. No. 4 class. He states that because all but three S.C. No. 4 customers do not utilize mains smaller than 4 inches in receiving service, this adjustment reflects cost causation.

Staff continues that the Companies' engineering witnesses, David Lazzaro and Mark Kinzle respectively stated that smaller diameter mains support service to the S.C. No. 4 customers. In fact, the Companies design and operate their systems in an integrated manner. The fact that a customer is directly served by a main that is four-inches, or greater, does not mean that smaller diameter pipe is not useful, or in some instances, necessary, in serving that customer. Staff maintains that operating the system as an integrated whole enhances the reliability of service to all customers. For example, smaller diameter mains may backfeed the larger diameter main and support service to the S.C. No. 4 customer. A backfeed refers to an alternate flow path for the gas. Staff states that this may be important when an outage occurs, resulting from, for example, required maintenance activity or third party damage to the Companies' facilities.

Staff adds that Companies witness Hoffman Malueg states that all service classifications portrayed in the Companies' ECOS studies receive service directly from all sizes of distribution mains. The only purpose of delineating between small and large distribution mains within the Companies' ECOS studies would be to segregate costs such that they can be allocated to the service classifications differently. However, because all of the Companies' service classifications are served from all sizes of distribution mains, there is no reason to delineate distribution mains within the ECOS studies. Additionally, the Companies' witnesses Mr. David Lazzaro and Mr. Mark Kinzle within their rebuttal testimonies explain that the Companies' distribution systems are an integrated network of various main sizes. Staff reasons that simply because a customer is directly served by a large distribution main does not preclude the fact that a small distribution main is useful in providing service to such customer. Given these reasons, Staff asserts that it is not appropriate to delineate between small and large distribution mains within the Companies' ECOS studies.

Staff mentions as well that AG/ELPC witness Rubin also addressed this issue and disagreed with the IIEC's proposal. Mr. Rubin stated that the IIEC ignores the fact that customers in the S.C. No. 4 class are served by mains in the 4 inch and smaller category, as the Companies indicated in several data request responses. Mr. Rubin opined that there was no factual support for IIEC's position on this issue.

<u>IIEC's Position</u>

IIEC argues that another flaw in the Companies' cost of service study is the Companies' failure to distinguish between small and large distribution mains. IIEC proposes to delineate the costs of the mains smaller than 4 inches and allocate those costs to all classes except for the S.C. 4 class.

IIEC states that the Companies do not delineate between small and large distribution mains and argue that because all of the Companies' service classifications are served from all sizes of distribution mains, there is no reason to delineate distribution mains within the ECOS studies. IIEC witness Collins argues this is not true. The Companies' system of mains is akin to the branches of a tree; the gas flows from the largest diameter mains into successively smaller sizes of mains. Large volume customers cannot be served by the smaller diameter mains, because mains with small diameters simply do not have sufficient capacity to supply those customers' needs.

IIEC maintains that its interest in this issue lies in the fact that only 3 customers out of 180 customers in the Companies' S.C. No. 4 class are served by mains less than four inches. The Companies' cost of service studies show net plant balances of $1.03 billion for PGL and $117 million for NS in FERC Account 376 - Distribution Mains. These plant balances include the cost of all distribution mains regardless of their diameter and the costs in these balances are distributed to all service classes on the basis of the inferior A&P allocation factors. IIEC reasons that in distributing main costs in such a manner the Companies' cost of service studies allocate the cost of 2-inch and 3-inch mains to customers that bear no responsibility for the Companies' investment in those mains, ignoring the principles of cost causation. It is not appropriate to allocate the costs of mains smaller than 4 inches serving only 3 S.C. No. 4 customers based on the combined load characteristics of all 180 S.C. No. 4 customers to the entire S.C. No. 4 rate class. Under such circumstances the cost of small mains should be delineated and those costs assigned to the customer classes other than S.C. No. 4.

IIEC states that the Companies' claim that smaller mains do in fact support the Companies' service to S.C. No. 4 customers. The Companies' witnesses argue the Companies design their systems in an integrated manner and the fact that a customer is directly served by a main that is four inches or greater does not mean that smaller diameter pipe is not useful and, in some instances, necessary, in serving that customer. They cite an example of this small diameter pipe's usefulness by suggesting the smaller diameter mains may backfeed the larger diameter main and support service to the S.C. No. 4 customer.

IIEC argues that Companies witnesses Mr. Lazzaro and Mr. Kinzle failed to support their backfeeding arguments with any credible examples of the actual necessity or the feasibility of such backfeed. In order to replace gas from larger pipes, the smaller diameter pipes would have to operate at a greater pressure than normal operating pressure to accommodate the increased volumes as a result of any such backfeed. IIEC maintains that due to the safety concerns, it is unlikely that backfeeding can occur in all circumstances or for long periods of time.

IIEC submits that neither Mr. Lazzaro nor Mr. Kinzle responded to Mr. Collins' question of safety or feasibility in their surrebuttal testimony. Neither witness provided any detail as to how often the smaller diameter mains are used to backfeed larger pipes that serve S.C. No. 4 customers or for what periods of time the smaller diameter mains can be safely used to backfeed. Neither witness indicates whether backfeeding has occurred on the system peak day. Finally, while backfeeding may be an ancillary service provided by the smaller diameter mains, backfeeding does not reflect normal operation of the system and is not mentioned by the Companies as a consideration in designing the T&D systems. IIEC claims that the arguments of the Company witnesses do not provide justification for allocation of 4-inch main cost to the S.C. No. 4 class.

IIEC notes that Company witness Hoffman Malueg argues the 3 S.C. No. 4 customers taking service from smaller mains ought not to receive a different cost of service than the other 177 S.C. No. 4 customers, nor should all the S.C. No. 4 customers receive no allocation of smaller diameter main costs when some customers (3 of 180) directly receive service from those mains. Ms. Hoffman Malueg further argues Mr. Collins' proposal is a selective exception to the class-based nature of the ECOS studies and not feasible to begin making exceptions for particular costs.

IIEC reiterates that only 3 customers out of 180 customers in Companies' S.C. No. 4 class are served by mains less than four inches. IIEC proposed in its rebuttal testimony that the Companies move the 3 customers who receive service from mains smaller than 4 inches to another service class if in fact those customers do not meet the qualification for service under the S.C. 4 tariff. If this were done, there would be no customer in the S.C. No. 4 class served by 4 inch mains and reallocation of those costs to other rate classes would be appropriate. In the alternative, the Companies should directly allocate the specific smaller than 4 inch main related costs used to serve these 3 customers to the entire S.C. 4 class. IIEC maintains that from a cost causation standpoint, either of these approaches is more appropriate than the Companies' proposal to allocate all mains smaller than 4 inches based on the combined load characteristics of all 180 customers in the S.C. No. 4 class.

IIEC submits that despite the protest of feasibility, identifying and allocating these costs is possible, especially in light of the fact there are only 3 S.C. No. 4 customers served by small mains. In fact, other Companies do directly allocate the costs of mains smaller than 4 inches used to serve a small number of its largest customers. IIEC concludes that Mr. Collins' adjustments to the allocation of small mains should be adopted.

<u>Commission Analysis and Conclusion</u>

The Commission agrees with the Utilities and finds that selective exceptions to the class-based nature of the ECOS studies are not appropriate in this instance. Customers in all the service classes (except for certain Peoples Gas negotiated rate customers) take service from all the different sized mains on the Utilities' systems. The ECOS studies are not intended to extract for or allocate specific costs to individual customers. Delineating mains by size within the ECOS study would be inconsistent with this approach, no matter how implemented. The Commission finds that the Utilities' decisions not to make delineations in their ECOS studies based on main diameter are reasonable.

IX. RATE DESIGN

A. Overview

<u>Companies' Position</u>

The Companies prepared ECOS studies to develop and implement their rate design proposals. NS Ex. 14.0; NS Exs. 14.1-14.8; PGL Ex. 14.0; PGL Exs. 14.1-14.8. The Companies assert that with few exceptions, the Companies' ECOS studies are substantially identical to those presented in the Companies' recent rate cases. *Id.* They have slightly modified how they allocated Uncollectible Expense (NS Ex. 14.0 at 17-18; PGL Ex. 14.0 at 18-19) and the Miscellaneous Revenues in Account 495 (NS Ex. 14.0 at 21-22; PGL Ex. 14.0 at 22-23).

The Companies' witness Ms. Egelhoff testified that the proposed rate designs were intended to and would accomplish the following six major objectives: (1) recover the revenue requirement, (2) better align rates and revenues with underlying costs, (3) send proper price signals regarding the costs recovered through the rates, (4) provide more equity between and within rate classes, (5) reflect gradualism considering test year revenue requirements, and (6) address the S.C. No. 2 distribution block structure and sizes. NS Ex. 15.0 at 6; PGL Ex. 15.0 REV. at 6.

<u>Staff's Position</u>

The Companies propose greater recovery of fixed costs through fixed charges. The Companies consider all of their costs recovered through base rates as fixed. Peoples Gas' classes are S.C. No. 1 Residential Heating and Non-Heating, S.C. No. 2 General Service, S.C. No. 4 Large Volume Demand Service, S.C. No. 5 Contract service for electric generation, S.C. No. 7 Contract service to prevent bypass, and S.C. No. 8 Compressed Natural Gas Service. North Shore's classes are the same as Peoples Gas except North Shore does not have a No. 8 Compressed Natural Gas Service class. The Companies also propose changes to various miscellaneous charges.

Staff recommends the Commission: (1) begin the process of adjusting the Companies' rate designs away from a straight fixed variable ("SFV") based rate design for the S.C. No. 1 Residential Heating and Non-Heating classes and the S.C. No. 2 General Service class; (2) accept the Companies' proposed rate design for Peoples Gas and North Shore's S.C. No. 4 Large Volume Demand Service rate class; (3) accept the Company's proposed rate design for Peoples Gas' S.C. No. 8 Compressed Natural Gas Service; and (4) accept the Companies' proposed Service Activation Charges, Reconnection Charges, and Second Pulse Data Capability Charges. Staff Ex. 4.0 at 4-5.

<u>AG's Position</u>

In their last distribution rate cases (Docket Nos. 12-0511/12-0512 (Consol.)), PGL and NS proposed to establish separate rates and customer classes for residential heating and non-heating customers, which was approved by the Commission. The proposal stemmed from the Commission's order in the Companies' 2011 cases that required the Companies to prepare cost-of-service studies that separated low-use residential customers from higher-use residential customers. AG/ELPC Ex. 3.0 at 6.

The result of separating heating and non-heating customers into different classes was a substantial reduction in the bills for non-heating customers, due to the significantly lower demand-related costs of serving those customers. The increases in Heating customers' customer charges that flowed out of the Heating/Non-Heating bifurcation, however, have been unnecessarily and inequitably amplified by the Companies' obsessive march toward increasing the amount of revenues recovered through the fixed customer charge. For example, Peoples Gas and North Shore residential heating customer charges have risen by nearly 200% and 179%, respectively, since 2007, the year PGL/NS began filing a steady stream of rate cases under its then new parent company, Integrys Energy Group. In fact, the Companies filed five rate cases over a seven-year period in their quest to increase profits and achieve the goal of maximum recovery of revenues through the customer charge. In 2007, the PGL customer charge was $9.00. Today for heating customers it stands at $26.91. In this case, Peoples Gas seeks to increase that charge another 43%, to a proposed $38.50. For North Shore customers, customer charge rates have increased from $8.50 in 2007 to the current $23.75. North Shore seeks to increase that charge another 24%, to a proposed $29.55 for heating customers.

Back in 2007, PGL and NS recovered, respectively, 27% and 28% of the residential revenue requirement through the customer charge, with variable *per* therm charges covering the remainder of the delivery service portion of the bill. In that year, PGL's flat monthly charge for both heating and non-heating customers was $9.00. *See* Docket Nos. 07-0241/07-0242 (Consol.), Schedule *E-2*, page 10 of 371. Today, it is $26.91 for heating customers. For North Shore, the residential customer charge was $8.50 in 2007 for both heating and non-heating customers. *See Docket No. 07-0241, North Shore Gas Co. – Proposed Increase in Delivery Service Rates*, Schedule E-2, page 8 of 261. Today it is set at $23.75 for heating customers. The bottom line is that Peoples Gas and North Shore customers pay the highest rates in the state – both in terms of the customer charge and *per* therm charges. PGL's and NS's extraordinary request to seek 43% and 24% increases in the Residential Heating customer charge, respectively, threatens to exacerbate that reality.

High customer charges mean the Companies' lowest users bear the brunt of rate increases, and subsidize the highest energy users. The Companies' claims that all costs are fixed is belied by their own cost studies, which identify significant operational costs as tied to demand of natural gas. Steadily increasing customer charges diminish the incentives to engage in conservation and energy efficiency because a smaller portion of the bill is subject to variable usage charges and customer efforts to reduce usage. AG/ELPC Ex. 3.0 at 15, 20-21.

The Commission should reject the Companies' unsupported claim that customer charges must be raised to ensure cost recovery. AG witness Rubin's proposed rate design (1) corrects the inequitable cross-subsidization of high users by low users of natural gas that occur when more and more costs are recovered through the flat customer charge; (2) reflects the Companies' minimal risk of recovering their authorized revenue requirement in light of the guaranteed revenue recovery that the Companies enjoy through decoupling, uncollectibles and infrastructure riders; and (3) furthers the public policy goals of promoting energy efficiency and conservation through higher variable charges. It should be adopted by the Commission.

ELPC Position

The ELPC intervened in this case in order to address one important issue, Peoples Gas' proposal to increase its fixed monthly charge for residential heating customers by 43.1%. The Commission should reject this proposal because it sends customers the wrong price signals regarding energy efficiency and it reduces customers' benefits from efficiency. While ELPC acknowledges that the Company should recover some of its fixed costs through fixed charges, the current allocation ratio already allows the Company to recover an adequate percentage. This issue has sparked ongoing debate in Illinois, but the Commission succinctly addressed the issue in a recent 2013 report to the General Assembly that recommends shifting revenues out of the fixed charges back in the variable charges. As set forth below, the evidence in this docket supports those findings.

City-CUB's Position

The Companies have made efforts to increase their fixed cost recovery by increasing the customer charge in each of their last four rate proceedings. *See* Docket Nos. 12-0511/12-0512 (Consol.), Order at 227; Docket Nos. 11-0280/11-0281 (Consol.), Order at 188 ("The trend in the Companies last three rate cases has been to request substantial increases in the customer charge, which may impact low use customers in excess of their cost of service or their contribution to demand-related costs."). Peoples Gas currently recovers about 55% of total base rate revenues from fixed charges, (PGL Ex. 15.0 at 11), and North Shore Gas currently recovers about 67% of total base rate revenues through fixed customer charges, (NS Ex. 15.0 at 11). The Companies' proposed rate designs in this proceeding continue their incessant campaign to move toward greater fixed cost recovery. The Companies propose to recover 90% of non-storage related fixed costs through the customer charge for residential non-heating customers (S.C. No. 1 NH) for both Companies, (NS Ex. 15.0 at 11; PGL Ex. 15.0 at 11), and for residential heating customers the Companies' proposed rate designs would allow NS to recover 80% and PGL 75% of their designated (non-storage related) "fixed costs" through fixed monthly charges. PGL-NS Ex. 29.0 at 4.

The Companies' proposal departs from recent decisions by the Commission that rejected proposals to move further toward an SFV rate design through increased customer charges. *See, e.g. Commonwealth Edison Co.*, Docket No. 13-0387, Order at 75 (Dec. 18, 2013); *Ameren Illinois Co*., Docket No. 13-0476, Order at 101-102 (March 19, 2014).

Instead of seeking to increase the fixed charges that customers face, the Commission's ComEd RDI Order stated its policy support for correctly returning to cost-causation based rate design. Both Staff and AG/ELPC witnesses oppose the Companies' continued pursuit of a self-serving SFV design.

CUB/City recommend that the Commission adopt the AG/ELPC proposed rate design that allocates any revenue requirement increase to the S.C. No. 1 volumetric charges and caps the customer charge at the current percentage of revenues, for both heating and non-heating customers.

B. General Rate Design

1. Allocation of Rate Increase

Companies' Position

The Companies used their ECOS studies to allocate revenue requirements and develop rates. As in prior cases, the Companies set cost-based rates for each service classification. The Companies stated that their ECOS studies and the descriptions of their rate designs are detailed and specific enough that it would be straightforward to derive rates from the revenue requirements the Commission approves. IIEC proposed an "across-the-board" increase (IIEC Ex. 1.0 at 24), *i.e.*, each service classification should receive the same percentage of the revenue deficiency as the overall system deficiency, regardless of what the ECOS studies show. The Companies opposed IIEC's proposal for several reasons.

First, the Companies stated that the premise for IIEC's allocation proposal is its two proposed changes to the Companies' ECOS studies. The Commission should reject both proposals. Second, the Companies claim that IIEC has failed to provide support for an across-the-board increase or to address how these resulting costs should be used to set rates and that the IIEC has failed to offer any rates and bill impacts that would result if such an allocation were approved. In addition, the proposal would not result in cost-based rates for any service classification and would create cross-subsidization across service classifications. NS-PGL Ex. 29.0 REV at 21-22. Third, despite IIEC's citing the importance of cost causation in the ECOS studies, the Companies stated that it is incongruous for IIEC to ignore the ECOS studies to design rates. Fourth, the Companies argued that the Ameren case cited by IIEC does not support its proposal. In *Central Illinois Light Company d/b/a AmerenCILCO, et al.*, Docket Nos. 07-0585 et al., Order (Sept. 24, 2008), the Commission approved an across-the-board increase because of the unique circumstances of that electric utility's transition from a legislatively mandated rate freeze. The Commission stated that it was "reluctant to return to full cost based rates after less than one year. The rate shock that would result from returning to full cost based rates would likely lead to another redesign docket." The Commission further stated that it "certainly does not mean to suggest by this decision that cost based rates have fallen out of favor. Indeed, cost based rates, as we affirmed in our recent decision in Docket No. 07-0566, continue to be the Commission's preferred rate design methodology." AmerenCILCO at 280.

Staff's Position

The Companies state that if the Commission approves a revenue requirement other than that proposed by the Companies, they will make the necessary adjustments to the appropriate ECOS studies' accounts and allocators based on the findings in the Commission order in this proceeding. Assuming that the Commission approves the Companies' proposed rate design, the resulting allocation of the revenue requirement by rate and customer class from the ECOS studies will then be used to set charges as discussed in the direct testimony of Companies witness Egelhoff and by using the formulas reflected in the supporting rate design work papers. Staff Ex. 4.0 at 25.

Staff has no objection to the Companies' proposal to re-run the ECOS studies and adjust the rate design based upon the Commission's final Order. *Id.* The IIEC states that due to the flaws in the Companies' cost of service studies, it proposes an across the board increase. IIEC Ex. 1.0 at 24.

The Companies disagree with IIEC's proposed across the board increase. The Companies state that they primarily base their rate design on the ECOS study. NS-PGL Ex. 29.0 REV at 21. Mr. Collins states that this across-the-board approach is supported by the modified cost of service studies sponsored by his colleague, Ms. Amanda M. Alderson. IIEC Ex. 1.0 at 25. However, these cost of service studies contradict Mr. Collins' argument for an across-the-board increase because they show that each service class causes different allocations of the proposed revenue deficiencies.

AG's Position

AG/ELPC witness Rubin dismisses IIEC's proposed across-the-board increase. Mr. Rubin states the IIEC witness Collins is the only witness who recommended any changes in the study. His changes are not appropriate, as they are neither supported by the facts nor consistent with the Commission's standard practice. Moreover, even if one of his recommendations were properly supported, that does not render the study itself to be flawed. AG/ELPC Ex. 9.0 at 13. The AG/ELPC also stated that another IIEC witness (Ms. Alderson in IIEC Exhibit 2.0) had no trouble using the Companies' cost models to produce new results using Mr. Collins's assumptions. Thus, there is no basis for concluding that the Companies' cost-of service studies are "flawed" or unable to be modified to produce reliable results. *Id.*

IIEC's Position

IIEC is recommending an across-the-board increase for PGL and NS. Each service classification should receive the same percentage of revenue deficiency as the overall system deficiency shown for each Company, respectively, regardless of what the Companies' ECOS studies show as the revenue deficiency for each individual service classification. IIEC Ex. 1.0 at 24. Based on the results of the modified Companies' cost of service studies performed by IIEC witness Alderson (IIEC Ex. 2.1) using the CP allocation for T&D related capacity costs as well as utilizing the small mains adjustment, an across-the-board increase is reasonable and results in moderate increases for all classes.

The Companies contend that allocating the same revenue deficiency to each service classification gives no regard to the results of the ECOS studies, which provide the portrayal of cost causation by service classification. NS-PGL Ex. 28.0 at 12. However, IIEC has shown how the Companies' ECOS study results are flawed and while the Companies may claim they "portray" cost causation, IIEC has illustrated how they in fact do not assign costs in a cost causative manner. The system average increase is appropriate when a cost study is flawed and does not provide reliable results. IIEC Ex. 3.0 at 17.

Alternatively, if the Commission does not approve of an across the board increase for all Peoples' rate classes, the IIEC supports a revenue allocation for Peoples based on the results of IIEC's cost of service study that includes both the CP allocation of demand costs and the small mains adjustment shown in IIEC Ex. 2.1. This would result in the S.C. 1 class receiving 82% of the system average increase approved by the Commission for Peoples. The S.C. 2, S.C. 4, and S.C. 8 classes would receive approximately 138%, 118%, and -78% of the system average increase approved by the Commission, respectively. IIEC continues to recommend a system average increase for NS's rate classes.

An Across-the-Board Increase Supports the Principle of Gradualism

Comparing the results of the IIEC modified Companies' cost of service studies presented in IIEC Exhibit 2.1 to an across-the-board increase, shows an across-the-board increase is reasonable because it results in moderate increases for all classes. IIEC Ex. 3.1. Reflecting gradualism prevents any one class from experiencing rate shock.

Gradualism reflects a gradual change in rates to move toward cost of service over time, as opposed to drastic changes in rates to move immediately to cost of service. IIEC Ex. 3.0 at 18.

Company witness Egelhoff argues that IIEC fails to provide support for an across-the-board increase or address how the resulting costs should be used to set rates. NS-PGL Ex. 29.0 at 21. As stated previously, the system average increase is appropriate when a cost study is flawed and does not provide reliable results. IIEC Ex. 3.0 at 17. An across-the-board approach has previously been approved by the Commission in Docket No. 07-0585 in which the Commission granted Ameren Illinois Companies an across-the-board increase for both electric and gas rates. *Id.* at 18.

Companies' witness Hoffman Malueg argues in addition to failing to provide evidentiary support for an across-the-board increase, Mr. Collins failed to consider the impacts upon cost classifications within the ECOSSs, which in turn would have impacts upon rate design. NS-PGL Ex. 28.0 at 252-254. However, IIEC has considered that fact and would expect that the resulting revenue allocation from an across-the-board increase by rate and customer class would be used to set the charges using the Companies' proposed rate design formula. IIEC Ex. 3.0 at 18-19. IIEC argues the Company would have to use the same process to design rates under its proposal as it would if the Commission approves rate increases to the classes that differ from the Companies' proposal.

Commission Analysis and Conclusion

The Commission rejects both of IIEC's proposed changes to the ECOS studies, and that makes IIEC's rate allocation proposal moot.

In addition, the cost of service studies contradict Mr. Collins' argument for an across-the-board increase. They show that each service class causes different allocations of the proposed revenue deficiencies. The Commission finds that IIEC has failed to provide adequate support for an across-the-board increase. Its proposal would not result in cost-based rates for any service classification and would create cross-subsidization across service classifications. The proposal fails to address how his proposal would impact the recovery of cost based storage costs recovered under Rider SSC, Storage Service Charge, as well as the determination of baseline uncollectible amounts by service classification that are reconciled under Rider UEA.

2. Fixed Cost Recovery

Companies' Position

The principal rate design issue in this case is the type of charge -- fixed or volumetric -- through which the Utilities should recover non-storage demand-classified distribution costs. The Companies contend that their proposals strike an appropriate balance between recovering all fixed costs in fixed charges, which is driven by the fact that fixed costs do not vary with gas use, and moving gradually to such a rate design, recognizing that the Companies' Rider VBA, addresses the inevitable over- and under-recovery that results from recovering fixed costs in variable charges. NS-PGL IB at 123-127.

Staff and intervenors advocate placing more fixed cost recovery in variable charges as a "traditional" rate design, citing recent electric utility orders as support for moving more fixed cost recovery to variable charges, arguing that their rate designs promote energy efficiency. They also cite certain of the Companies' riders as a reason to have less fixed cost recovery in fixed charges, and claim that the Companies' rates result in low use Service Classification ("S.C.") No. 1, Small Residential Service, customers subsidizing high use S.C. No. 1 customers.

The Companies noted that Staff and intervenors refer to "SFV" rate design repeatedly. The Companies explained that SFV is merely a term describing a rate design under which all fixed costs are recovered in fixed charges. NS Ex. 15.0 at 13; PGL Ex. 15.0 REV. at 13. Contrary to at least one intervenor's claims (City/CUB IB at 7), the Companies have not proposed an SFV rate design, nor are their current rates based on an SFV rate design. NS-PGL Ex. 29.0 REV. at 4. The Companies' witness Ms. Egelhoff did state that, absent the Companies' decoupling mechanism (Rider VBA), which is under Illinois Supreme Court review, SFV is the appropriate rate design. NS Ex. 15.0 at 13; PGL Ex. 15.0 REV. at 13. An SFV rate design is not before the Commission in this case.

Demand Costs Are Fixed Costs

The Companies explained that demand-classified costs (*e.g.*, storage, land, structures and improvements, mains, compressor station equipment and measuring and regulating equipment) are fixed costs. The costs of this type of investment do not vary with customer usage or even if the customer's demand day requirements change. NS PGL Ex. 43.0 REV. at 4. When North Shore or Peoples Gas installs a main to serve a residential customer, the cost of that main, included in setting the revenue requirement that will underlie rates in this 2015 test year case, will not change from day-to-day or year-to-year simply because the customer uses more or less gas on the peak day or any other day. *Id.* at 5-6. The Companies contrasted the demand costs with, for example, the quantity of gas that the Companies purchase to serve customers, which does vary with usage. For demand costs, the amount included in base rates in the test year is the same whether a customer consumes 0 therms or 100 therms and will not change even if the customer class' peak day usage increases or decreases. *Id.* The Companies acknowledged that the way to recover demand costs is often contested, but, citing an authoritative NARUC source, the costs are clearly fixed. NS-PGL Ex. 29.0 REV. at 8.

The Companies also explained that the example of the demand of different size homes does not support Staff's and intervenors' arguments. There is no support for their premise that the cost of the main is different because a customer's home is 1,000 square feet and another customer's home is 4,000 square feet. The costs incurred to serve a community containing either size home would be comparable. In the example given and considering not just a single home but a community with like-sized homes, the same size main and services would be used to supply each community. The Companies' explained that the size of the service and the cost to install would be the same for both size homes. NS-PGL Ex. 38.0 at 8; NS-PGL Ex. 45.0 at 4.

The Companies posited that the question is, in the absence of a demand charge, whether to recover these fixed costs in a customer charge, a distribution charge, or both. (The Companies noted that a demand charge would be a way to recover demand costs. However, Staff, confusingly, refers to "distribution\demand charges." Staff IB at 95, 100. They are not the same. NS-PGL Ex. 29.0 REV. at 14.) The Companies' rate design, in this and prior cases, generally recovers the demand costs in both fixed and variable charges, with gradual movement towards placing recovery of these fixed costs in fixed charges. *See, e.g.*, NS Ex. 15.0 at 11, 16; PGL Ex. 15.0 REV. at 11, 16. The problem with Staff and intervenor proposals to place all S.C. No. 1 demand costs in variable charges is that it necessarily presumes that usage affects demand costs. (Staff also makes proposals for other service classifications that stem from the same arguments.) It is correct that system peak day usage drives the size of demand-related infrastructure (NS-PGL Ex. 29.0 REV. at 7), but it is false that day-to-day usage causes any change to these costs. Under the Staff and intervenor proposals, when a customer uses more gas -- on a peak or other day -- he pays more towards demand costs, and when he uses less gas, he pays less towards demand costs. Yet, the same main or regulator is still in base rates and still supporting service to that customer. *Id.* at 7-8. For these reasons, for a rate class that does not include a demand charge, a fixed charge, like the customer charge, is a much better cost causal rate design than a variable charge, like the distribution charge.

Energy Efficiency

Companies' witness Ms. Egelhoff stated that one of the Companies' rate design objectives is to send proper price signals regarding the costs that are the subject of the rates being set in these cases. They achieve this by proposing to move more fixed cost recovery into fixed charges. The price signal conveyed to customers is the cost to serve them, *i.e.*, how much gas the customer uses does not affect the cost to deliver gas to that customer. The Companies contrast this accurate price signal with the erroneous price signals that the Staff and intervenor proposals would send, namely that the more gas customers use the more it costs the Companies to provide them delivery service. Stated differently, Staff and intervenor proposals falsely tell customers that lower usage reduces the Companies' costs to provide delivery service. NS-PGL Ex. 29.0 REV. at 3-4. The Companies contend that the purpose of rate design is not to manipulate customer behavior but, inter alia, to recover the revenue requirement and better align rates and revenues with underlying costs.

Ms. Egelhoff explained that energy efficiency is addressed through other means. The Companies' energy efficiency programs, under Section 8-104 of the Act and that the Commission most recently approved in Docket No. 13-0550 and before that in Docket No. 10-0564, are designed to achieve statutorily-required energy efficiency goals, through customer participation in the approved programs. Ms. Egelhoff stated that the Commission approved a budget and the Companies recover the costs of their programs under their Rider EOA, Energy Efficiency and On-Bill Financing Adjustment. The Illinois General Assembly and the Commission intend that costs related to conservation and energy efficiency measures occur within the context of the Companies' approved Section 8-104 plans and not through rate design that sends incorrect price signals. NS-PGL Ex. 29.0 REV. at 10. Through the Section 8-104 programs and providing for volumetric cost recovery under Rider EOA, the Commission provided a clear signal as to how the Companies are to implement and recover costs for their energy efficiency programs. The Companies' gas distribution service to residential customers in single family homes and multi-family buildings is entirely driven by fixed costs. The mere presence of the customer for a particular account drives the nature of the cost of the utility service (*e.g.*, the meter and main) to that premises. NS-PGL Ex. 29.0 REV. at 11.

The Companies also showed that customers have ample incentives to reduce gas use. Under their proposals, a large portion of a typical S.C. No. 1 heating customer's annual bill before taxes would be derived from variable charges such as supply and distribution (approximately 60% for Peoples Gas and 70% for North Shore). *Id.* at 9. Also, under any rate design, gas costs remain one of the largest portions of an average residential heating customer's annual bill, with the cost of gas constituting approximately 40% for Peoples Gas and 55% for North Shore. NS-PGL Ex. 29.0 REV. at 9-10. The Companies cited the Commission's conclusions in a Nicor Gas case, "[t]he portion of fixed costs that are currently recovered through a volumetric charge are in fact fixed costs, and thus cannot be conserved. Moving a greater percentage of fixed cost recovery to fixed charges rather than volumetric charges provides a more stable revenue stream and sends a better price signal to the consumer." *Northern Illinois Gas Company d/b/a Nicor Gas Company*, Docket No. 08-0363, Order at 91 (Mar. 25, 2009).

<u>Rider Mechanisms</u>

The Companies acknowledged that the various riders that Staff and intervenors cited provide stability for customers and the Companies. For example, Rider VBA is a rate design mechanism designed to prevent over- or under-recovery of the Companies' Commission-approved revenue requirement. Docket Nos. 11-0280/11-0281 (Consol.), Order at 163. Rider UEA, Uncollectible Expense Adjustment, is designed to provide recovery (not over- or under-) of the Companies' uncollectible amount (bad debt). 220 ILCS 5/19-145. Rider SSC, Storage Service Charge, does the same for base rate storage costs and was needed to support unbundling that the Commission required for certain transportation programs. Docket Nos. 11-0280/11-0281 (Consol.), Order at 229. However, these mechanisms do not support rates that are not founded on sound cost causation principles. They are not (contrary to Staff's analogy (Staff IB at 100)) comparable to EIMA. Rider VBA, for example, does not provide for the recovery of any costs outside of the approved revenue requirement, nor does it allow adjustments based on actual costs being more or less than the approved revenue requirement. Under EIMA, the reconciliation is far more than a simple true-up of amounts billed to customers to an approved revenue requirement. EIMA looks at all actual non-fuel costs in its reconciliation. With some limits, the EIMA process takes into account higher or lower costs. NS-PGL Ex. 29.0 REV. at 6. Movement away from fixed cost recovery in fixed charges thus has much less of an effect on the electric Companies' ability, under EIMA, to recover its revenue requirement than it does on gas Companies.

Low Use/High Use Customers

The AG argues that the Companies' rate design proposals would create intra-class subsidies (with low use customers subsidizing high use customers) and are unfair to low income customers. AG IB at 83-84, 92-97. The Companies contend that the AG arguments fail for two fundamental reasons. NS-PGL RB at 108-110.

First, the cross-subsidization argument is premised on not recognizing that demand costs are fixed costs. Indeed, the Staff and intervenor proposals could result in high use customers subsidizing low use customers. NS-PGL Ex. 43.0 REV. at 9.

Second, the AG equates low use customers with low income customers and their arguments are predicated on taking general data about the city, county, state or other region and applying it to the Companies' customer bases to categorize customers as low income. Neither the Companies nor the AG have income information about the Companies' customers. The AG witness used general data to draw conclusions, and tried to explain away utility data that were contrary to his theory. The Companies only have Low Income Home Energy Assistance Program ("LIHEAP") and percentage of Income Payment Program ("PIPP") customer-specific data to identify North Shore's and Peoples Gas' low income customers. The data Peoples Gas provided AG witness Mr. Colton show that an average Peoples Gas low income (*i.e.*, LIHEAP and PIPP) S.C. No. 1 heating customer uses more (not less) gas than the typical such customer (1,258.60 therms versus 1,066.62 therms). NS-PGL Ex. 29.0 REV. at 22, 24. The AG witness tried to dismiss these data by saying they were a function of what he considers the Companies' inappropriate definition of low income customers. AG Ex. 4.0C at 11; AG Ex. 10.0 at 9-10. The AG's witness ignored the customer-specific data Peoples Gas provided, which contradicted his theory that low income customers are low use customers, and instead claimed the data were flawed because they did not use his definition of low income. NS-PGL Ex. 43.0 REV. at 11.

The Companies responded to the Commission's concerns about distinguishing low use and high use residential customers by proposing S.C. No. 1 non-heating (sometimes identified by "NH") and heating (sometimes identified by "HTG"), which the Commission approved. S.C. No. 1 NH rates accurately reflect the lower costs of serving these lower use customers who place less demand on the system. The Companies do not have service classifications based on customer's income, nor do they agree that subsidizing low use customers on the premise that it may be beneficial to low income and elderly customers is a sound rate design. However, low income customers' needs are addressed through targeted assistance programs that are available irrespective of a customer's usage levels. Even low income customers with higher than average use may be eligible for assistance. The Companies also offer energy efficiency programs and on-bill financing programs to all customers, encouraging them to adopt energy efficiency measures and practices. NS-PGL Ex. 29.0 REV. at 23.

The Companies' S.C. No. 1 rate design takes low use and high use customers into account through the heating and non-heating rate design. The fact that the bill impacts, in percentage terms, are higher for low use customers than for high use customers is not evidence of inappropriate intra-class subsidies, but rather is evidence of simple mathematics: the percentage effect of an increase in the fixed customer charge will be greater for a low use customer, compared with a high use customer, because the increase is applied to a smaller bill.

<u>Staff's Position</u>

The Commission should accept Staff's and the AG's recommendation to begin moving away from SFV-based rate design. The Commission's recent Orders in ComEd (Docket No. 13-0387) and Ameren Illinois (Docket No. 13-0476) make it clear that SFV-based rate designs should be re-examined and rate design should reflect traditional rate design principles, which more closely align customers' bills with the ECOS study. The Commission is actively reevaluating how rate design can be utilized to ensure that customers are responsible for the demands they place on the system and that rate design maximizes conservation efforts.

Staff witness Johnson explained that traditionally, rate design aligned customer charges with the ECOS study customer costs and aligned *per* therm distribution charges with the ECOS study demand costs. Staff Ex. 4.0 at 20. The Companies' proposals to increase fixed cost recovery through fixed charges (NS Ex. 15.0 at 9 and PGL Ex. 15.0 REV at 9) is a SFV-based or modified SFV rate design that shifts recovery of some of the ECOS study demand related costs to the customer charge and away from the *per* therm distribution charge. The result reduces the effect of increased usage on the customers' bill. When a customer charge is based upon all of the ECOS study customer costs and part of the ECOS study demand costs, the resulting *per* therm distribution charge is lower than it would have been if all demand costs were recovered through the distribution charge. The Companies' rate design can encourage increased consumption through lower *per* therm distribution charges rather than discouraging it through higher *per* therm distribution charges. Thus, the price signal for ratepayers to conserve is weakened. Staff Ex. 4.0 at 20.

Staff witness Johnson recommends the Commission move away from a SFV-based rate design. In Docket No. 13-0387, the Commission adopted adjustments to ComEd's SFV-based rate design in Docket No. 13-0387, which moved away from SFV-based rate design through lower fixed cost recovery. Staff Ex. 4.0 at 16. The rate design the Commission approved in the ComEd case set customer charges based upon the ECOS study's customer costs and demand charges based upon the ECOS study's demand costs. Docket No. 13-0387, Order at 68.

Additionally, in Ameren Illinois Company's ("Ameren") most recent revenue neutral electric rate design case (Docket No. 13-0476) the Commission directed Ameren to maintain the current percentage of fixed cost recovery through fixed charges (44.8%) for the DS 1 residential class, even though the Company requested an increase to 50% fixed cost recovery through a modified SFV rate design, with the expectation that the issue would be revisited in Ameren's next rate design proceeding.

One of the main drivers the Commission noted behind its rejection of the AG's proposal to move away from SFV-based rates and significantly reduce the fixed cost recovery through fixed charges in the Ameren case was the potential to create rate shock for a significant number of electric space heating customers. While such concerns could have been addressed by a phased-in approach, the record was insufficient to implement such an approach. Therefore, the Commission did not adopt the AG's proposal, yet still rejected Ameren's proposal to increase fixed cost recovery through fixed charges in its proposed modified SFV rate design. Docket No. 13-0476, Order at 102.

The Commission subsequently granted rehearing in Docket 13-0476 to provide the Commission with additional evidence about the bill impacts of moving away from an SFV rate design for residential customers. Ameren Illinois proposed adopting a SFV rate design for the DS-1 class customer charge to recover 44.8% of the DS-1 revenue requirement from the monthly non-volumetric charges. The AG proposed a rate design through which the Company would recover approximately 28% of its revenue requirement through the non-volumetric charges. Docket No. 13-0476, Order on Rehearing at 40 (September 30, 2014). The Commission reiterated its support for a discontinuation of the shift toward a greater SFV rate structure:

The Commission ultimately accepted Staff's proposal that continues the movement away from a SFV rate design and shifts to a rate design that decreases the fixed customer charge and increases the variable charges, while protecting against the potential for significant bill impacts, as initially contemplated in the original Docket No. 13-0476 March 19th Order. Docket No. 13-0476, Order on Rehearing at 42.

These recent Commission orders adopt rate designs that move away from a SFV-based rate design and instead align customers' bills with the cost of service (*i.e.*, customer charges based upon ECOS study customer costs and distribution/demand charges based upon ECOS study demand costs). *Id.* at 19. It is clear the Commission is considering how rate design can be utilized to ensure that customers are responsible for the demands they place on the system and that rate design maximizes conservation efforts. Additionally, the Commission is weighing the effects of the EIMA on revenue stability in the electric industry and the gradualism needed in adjusting SFV-based rate design because of potential rate shock. *Id.*

Peoples Gas and North Shore have implemented Rider VBA which stabilizes the distribution revenue requirement approved by the Commission in the Company's most recent rate proceeding. Peoples Gas has also implemented Rider QIP, which allows the Company to recover a return on, and depreciation expense related to, the Company's investment in qualifying plant because the Company's last rate case. Peoples Gas, ILL.C.C. No. 28, Sheet No. 130-138.2. Both of these riders are rate recovery mechanisms that mitigate concerns regarding revenue stability. *Id.* at 19-20.

The Companies' ECOS studies take functional costs and further classify them by cost causation into commodity related, demand related, and customer related. Each class is then assigned commodity, demand, and customer related costs. Adoption of the Companies' rate design would create inconsistency between how costs are caused and how revenues are collected. For example, the Companies' proposed SFV-based rate design recovers some demand related costs, such as distribution mains, through the customer charge and therefore shifts cost recovery from a *per* therm basis to a *per* customer basis. Staff Ex. 4.0 at 21. The inconsistency arises because assigning demand related costs to the customer charge assumes each customer in the class contributes equally to the class demand. There is no evidence in the record to support this assumption. Furthermore, that assumption is inconsistent with the way demand costs are allocated among the customer classes. Demand related costs are allocated among customer classes based on demand, not based upon the assumption that each customer contributes equally to demand.

AG/ELPC witness Rubin also recommends that the Commission reject the Companies' proposals to move closer to straight fixed-variable rate design. He states that moving towards SFV rate design would create inequities and cross-subsidies within the residential space heating class. He also concludes that SFV rate design is unnecessary, given the use of other rate mechanisms to achieve revenue stability, and that it is contrary to the State's energy efficiency policies. AG/ELPC Ex. 3.0 at 3.

The Companies' responded that all of their costs (ECOS study customer and demand costs) are fixed and that fixed costs should be recovered through the customer charge for S.C. No. 1 and S.C. No. 2 classes. Companies' witness Egelhoff states that the Commission has endorsed policies in several rate proceedings to increase the fixed cost recovery through fixed charges. With respect to demand costs alone, Ms. Egelhoff states that demand costs, by definition, are driven by customer demand on the peak day. NS-PGL Ex. 29.0 REV at 7. The infrastructure that is put in place to handle the demand will cost the same regardless of the amount of demand that is placed on the system at any given time. *Id.* at 8.

Ms. Egelhoff's statement misses the point. The relevant question here is not the cost of the infrastructure built to meet demand but rather who should pay for it. If demand costs are recovered through the customer charge, all customers are assumed to cost the same for the Companies to serve them. Staff Ex. 9.0 at 7. If demand costs are recovered through the distribution charge, the recovery method assumes the costs are not the same for all customers to serve them. If demand costs are recovered through the distribution charge, that assumes that customers with higher usage will have higher peak demands and be more costly to serve than small use customers. While this latter assumption may not be true in each and every case, it is more reasonable than the Companies' proposed rate design's implied assumption that all customers within a class cause the utility to incur the same amount of demand costs.

Staff also observed that the Companies' approach does not encourage conservation as much as Staff's rate design, which recovers a greater share of costs through variable charges and thereby increases the financial incentive for customers to adopt conservation measures. Although gas costs comprise a portion of a customer's total monthly gas bill, the customer is still concerned about the total bill. Recovering distribution demand costs on a *per* therm basis increases the incentive to conserve. In contrast, the Companies' rate design recovers some of the demand costs on a *per* customer basis instead of a *per* therm basis. This causes the distribution charge to be lower compared to if all of the demand costs were recovered on a *per* therm basis. Thus, the price signal for ratepayers to conserve is weakened. Staff Ex. 9.0 at 8.

A recent ruling by the 2nd Circuit Court of Appeals upheld a Commission tariff that permitted Peoples and North Shore Gas to reconcile over or under recovery of revenues resulting from deliveries being higher or lower than anticipated. The result of this ruling is that the Commission can provide a mechanism for revenue stability that lowers the monthly customer charges and increases the volumetric charges. Such a change can decrease energy use by providing a greater price signal without affecting the overall bill to an average retail customer.

The Commission has recognized that lower monthly customer charges and higher volumetric charges *(per* therm distribution charge) can decrease energy use by providing a greater price signal. Staff's rate design proposal, which lowers the customer charge and increases the volumetric charge compared to the Companies' proposals, encourages energy conservation to a greater extent than the Companies' proposal would. *Id.*

AG's Position

In their last distribution rate cases (Docket Nos. 12-0511/12-0512 (Consol.)), PGL and NS proposed to establish separate rates and customer classes for residential heating and non-heating customers, which was approved by the Commission. The proposal stemmed from the Commission's order in the Companies' 2011 cases that required the Companies to prepare cost-of-service studies that separated low-use residential customers from higher-use residential customers. AG/ELPC Ex. 3.0 at 6.

The result of separating heating and non-heating customers into different classes was a substantial reduction in the bills for non-heating customers, due to the significantly lower demand-related costs of serving those customers. The increases in Heating customers' customer charges that flowed out of the Heating/Non-Heating bifurcation, however, have been unnecessarily and inequitably amplified by the Companies' obsessive march toward increasing the amount of revenues recovered through the fixed customer charge. For example, Peoples Gas and North Shore residential heating customer charges have risen by nearly 200% and 179%, respectively, since 2007, the year PGL/NS began filing a steady stream of rate cases under its then new parent company, Integrys Energy Group. In fact, the Companies filed five rate cases over a seven-year period in their quest to increase profits and achieve the goal of maximum recovery of revenues through the customer charge. In 2007, the PGL customer charge was $9.00. Today it stands at $26.91. In this case, Peoples Gas seeks to increase that charge another 43%, to a proposed $38.50. For North Shore customers, customer charge rates have increased from $8.50 in 2007 to the current $23.75. North Shore seeks to increase that charge another 24%, to a proposed $29.55.AG/ELPC Ex. 3.0 at 25.

Back in 2007, PGL and NS recovered, respectively, 27% and 28% of the residential revenue requirement through the customer charge, with variable *per* therm charges covering the remainder of the delivery service portion of the bill. In that year, PGL's flat monthly charge for both heating and non-heating customers was $9.00. *See Docket No. 07-0242, Peoples Gas Light & Coke Co.* – Proposed Increase in Delivery Service Rates, Schedule E-2, page 10 of 371. Today, it is $26.91 for heating customers. For North Shore, the residential customer charge was $8.50 in 2007 for both heating and non-heating customers. *See Docket No. 07-0241, North Shore Gas Co. – Proposed Increase in Delivery Service Rates*, Schedule E-2, page 8 of 261. Today it is set at $23.75 for heating customers. The bottom line is that Peoples Gas and North Shore customers pay the highest rates in the state – both in terms of the customer charge and *per* therm charges. PGL's and NS's extraordinary request to seek 43% and 24% increases in the Residential Heating customer charge, respectively, threatens to exacerbate that reality.

While changes in rate design are intended to be revenue-neutral in impact, the practical reality is something different. In both the current and past rate cases, OAG expert Scott Rubin has repeatedly demonstrated in testimony that high customer charges mean the Companies' lowest users bear the brunt of rate increases, and subsidize the highest energy users. He has also demonstrated that the Companies' claims that all costs are fixed are belied by their own cost studies, which identify significant operational costs as tied to demand of natural gas. In addition, steadily increasing customer charges diminish the incentives to engage in conservation and energy efficiency because a smaller portion of the bill is subject to variable usage charges and customer efforts to reduce usage. AG/ELPC Ex. 3.0 at 15, 20-21.

As discussed further below, the Commission should reject the Companies' unsupported claim that customer charges must be raised to ensure cost recovery.

<u>City-CUB's Position</u>

The Companies' proposed rate design would require low-use/low-demand customers to subsidize high-use/high-demand customers. AG/ELPC Ex. 9.0 at 6. In fact, despite the proposed revenue requirement increase in this case, under the Companies' proposed rate design, some high use customers would see a decrease in their total distribution bill. AG/ELPC Ex. 3.0 at 15. PGL-NS claim that, under their proposed rate design, approximately 65-70% of an "average" residential heating customer's annual bill would be derived from variable charges. PGL-NS Ex. 43.0 at 6. However, the "average" low-use customer uses far less gas than the Companies' average customer, and low-use customers' resulting bills are much smaller. For those low-use customers, the amount of revenue derived from variable charges is far lower than for the class average customer, and the percentage of their bills attributable to fixed monthly charges is much greater.

In this delivery services rate proceeding, the Commission has jurisdiction to set – and should consider – only the portions of the customers' bills related to delivery services. Instead, the Companies' witness relies on comparisons and commentary respecting customers' total bills, which include commodity charges. This inappropriate comparison thus inflates the calculated amount of charges that vary for any given consumer, and deflates the calculated percentage of charges imposed through fixed monthly charges, especially for low-use/low-demand customers. Thus, (a) the actual relationship between proposed charges and cost-causing factors and (b) the impact of the proposed delivery service charges on customers are each distorted. The Companies' emphasis on total bills is an easily-perceived attempt at misdirection. The Commission should focus its review of customer bills on the portion of those assembled charges that is under the Commission's jurisdiction.

Within the residential service class, each customer in that class pays exactly the same fixed charge for demand-related costs under the Companies' proposed design. AG/ELPC Ex. 9.0 at 2. For the residential heating class, the Companies' ECOSS allocates demand costs only at the class level. Within the class, the Companies propose to spread demand costs uniformly across all customers, regardless of each customer's actual demand. Staff Ex. 9.0 at 4. The result is that low-use customers subsidize high-use customers in that class.

Even if one ignores the legislative policy of keeping gas utility service accessible, (220 ILCS 5/1-102(d)(viii)), the Companies' ECOSS justifies collecting a maximum of 63% of the total cost of service through the customer charge. AG/ELPC Ex. 3.0 at 15-16. However, to reach that 63% figure, one must accept the Companies' fiction that their demand costs are "fixed." But the Companies' ECOSS and the demand charges the Companies impose in other rate classes confirm that demand charges are not fixed. PGL Ex. 14.0 at 8; PGL Ex. 15.0 at 9, 10, 16, 19. Despite this limitation from their own study, which accepts their peculiar definition of "fixed" costs, the Companies propose to collect 75% or 90% of their revenues through fixed charges. PGL Ex. 15.0 at 12; 15. The Companies claim that this rate treatment of "fixed" costs -- which are inconsistently identified in their cost-causation based ECOSS -- does not produce the adverse effects detailed by other witnesses in this case. However, the Companies' claims are not validated by the record evidence or by common sense.

SFV Rates Abandon Cost Causation And Give Inaccurate Price Signals

The collective peak demands and energy needs of customers cause gas distribution facilities to be installed. Utility witnesses testify to the fact that a primary consideration in system design is to meet design day demand that may vary from year-to-year. In addition, Staff confirms that "[d]emand related costs service the peak demand of the system."

Accordingly, PGL-NS admit that there are good reasons for allocating the cost of distribution mains based on demand and usage. *Id.* at 3. As AG/ELPC witness Mr. Rubin observed, "[i]t makes no sense to say that the cost of serving residential customers is based, in part, on demand and energy usage; but then to design rates that ignore demand and energy usage." AG/ELPC Ex. 9.0 at 3.

A traditional rate design is more consistent with this cost causation relationship, as it is correctly defined by and recognized in the Companies' cost of service study. The Companies' proposed SFV rate design diverges from cost-causation, substituting its "fixed" cost designation for cost causation as the determinative allocator. Ms. Egelhoff claimed that the costs to install and maintain service needed to meet the demands of residential customers are likely to be the same by customer. This testimony is based on the belief that "demand-related costs do not vary by … the amount of demand [of] individual customers" whose collective demand is the cause of the Companies' demand costs. However, for most customers within a class, demands bear a pretty close relationship to annual usage. AG/ELPC Ex. 9.0 at 3, 7. The Companies' recommended rate design is aptly captured in AG/ELPC witness Mr. Rubin's restatement of the Companies' methodology: "well, we can't have precise demand metering, so let's just assume that every customer's demand is exactly the same." *Id.* at 7.

The Companies recover demand-related costs through demand-based charges in classes where customers have demand meters. The absence of demand meters in the Residential classes does not change the nature of those costs or why those costs are incurred, simply how they can be measured. Staff offers the illustrative example of a customer with a 4,000 square foot home paying the same amount for distribution mains as a customer with a 1,000 square foot home, even though the 4,000 square foot home customer "would use a larger share of distribution main capacity for its gas requirements." Staff Ex. 9.0 at 5. Honoring cost causation would require that the Companies' rates recognize that difference in what is used to provide service to those customers. As Staff witness Mr. Johnson observes, the Companies' proposal for a modified SFV rate design raises consistency issues. Under an SFV design, ECOSS-identified demand related costs, such as the cost of distribution mains, are labeled "fixed" and recovered through a uniform customer charge for all customers in the class.

The Commission has recognized the existence and effect of intra-class subsidies in the Companies' existing rate designs. Docket Nos. 12-0511/12-0512 (Consol.), Order at 218. The Commission's response was to approve a separation of non-heating customers from the rest of the residential class, as a means of recognizing the type of usage and demand cost differences the Companies' SFV proposal would ignore. *Id.* at 6-7. Ms. Egelhoff admits that the "fixed" costs that the Companies refer to are driven by customer demand and "can increase or decrease." PGL Ex. 8.0 REV. at 5; PGL-NS Ex. 29.0 at 7. If the costs of distribution facilities are collected based on customers' energy consumption or demand, then customers who consume more would pay most of any increase in demand costs, consistent with the correlation between usage and demand. Staff Ex. 9.0 at 4, 7.

Under a rate design that respects cost causation, demand-related costs should be collected (as causation suggests) through a demand charge, or through an energy charge if demand metering is unavailable. *Id.* at 5.

In any case, there is no revenue stability justification for the Companies' proposed rate design. The SFV design is proposed despite the existence of Rider VBA, which acts as a decoupling mechanism for S.C. Nos. 1 and 2 and reduces the Companies' financial risk of under-recovery of revenues. PGL-NS Ex. 29.0 at 5; Staff Ex. 4.0 at 19. The ICC has also reported that, because of Rider VBA, "the Commission can provide a mechanism for revenue stability that lowers the monthly customer charges and increases the volumetric charges. Such a change can decrease energy use by providing a greater price signal" to customers. *Id.* at 20 (quoting *Report to the Illinois General Assembly Concerning Coordination Between Gas and Electric Utility Energy Efficiency Programs and Spending Limits for Gas Utility Energy Efficiency Programs* at 23 (Aug. 30, 2013)).

In addition to Rider VBA, PGL has also implemented Rider QIP, which allows PGL to recover a return of and on the Company's investment in qualifying plant. The Companies also enjoy recovery of storage costs through Rider SSC. Further, PGL is essentially guaranteed a designated level of revenues for uncollectible accounts through Rider UEA.

SFV pricing, which the Companies advocate, fails to send customers an accurate signal about the costs associated with serving peak demands for natural gas. AG/ELPC Ex. 9.0 at 2. Acknowledging that fact, PGL-NS witness Ms. Egelhoff, referring to her proposed rate design, testified "I don't expect [customers] to change their behavior based on that message." Tr. at 138 (Sept. 23, 2014).

However, for that signaling effect, Ms. Egelhoff relies on charges that comprise a fraction of the total bill of an average PGL customer, and even less of a low-use/low-demand customer's bill. PGL-NS Ex. 29.0 at 9-10 (calculating that the cost of gas constitutes approximately 40% for Peoples Gas average residential heating customer's annual bill). In her testimony, Ms. Egelhoff identified the storage service charge, Natural Gas Savings Program, environmental charge, Uncollectible Expense Adjustment – Gas Cost adjustment, Volume Balancing adjustment, Qualified Infrastructure Plan charge, and taxes as variable components of a customer's bill. PGL-NS Ex. 43.0 at 6. However, Ms. Egelhoff admits that these charges comprise less than half the total bill of even the average Peoples Gas customer, l*et al*one a customer with lower usage than average.

By failing to send proper price signals, the Companies' proposed rate design denies consumers who conserve the benefit of their actions, and punishes customers who are frugal. The proposed SFV charges are indifferent to efficiencies in usage and demand. In contrast, the Commission has recognized that lower monthly customer charges and higher volumetric charges can advance energy use conservation and efficiency policy objectives by providing a greater price signal. Staff Ex. 9.0 at 8-9.

The Companies' Proposed Rate Design Undermines Legislative And Commission Policies Supporting Energy Conservation And Efficiency

The Companies also offer the false hope of encouraging conservation through their proposed rate design. Ms. Egelhoff claimed that customers' incentives to conserve are provided through required energy efficiency programming and that incorporating conservation into rate design is improper because it is "contrary to cost causation principles." PGL-NS Ex. 43.0 at 7. However, the Companies' proposal violates cost causation principles by failing to "properly recognize that customers with different demands impose differing costs on the system." Staff Ex. 9.0 at 5. The assumption behind Staff's and AG/ELPC's proposed rate design is more reasonable than the Companies' implied assumption that all customers within a class cause the utility to incur the same amount of demand costs. *Id.* at 7.

Ms. Egelhoff's claim further ignores the General Assembly's explicit directive to encourage energy efficiency. Section 8-104 of the PUA makes clear the General Assembly's interest in reducing the amount of natural gas delivered to utility customers and reducing the cost of utility bills that customers pay. The Companies' proposed rate design undermines the statutory programs by reducing the amount of a customer's bill that the customer has control over. The Commission has already recognized that reducing the fixed charges of customers can reduce overall natural gas usage, as envisioned by the General Assembly in creating the 8-104 energy efficiency programs.

(Report to the Illinois General Assembly Concerning Coordination Between Gas and Electric Utility Energy Efficiency Programs and Spending Limits for Gas Utility Energy Efficiency Programs at 24 (Aug. 30, 2013)).

Despite the proposed reduction in customers' ability to control their bills through favored conservation and efficiency actions, the Companies claim that SFV rate design provides a benefit in reducing the volatility of customers' bills. That is, customers would pay a fixed monthly charge that is unaffected by variations in weather or other conditions. In addition to ignoring the inflated charges incurred during the summer period, the Companies never establish why reducing customer bill volatility should be the objective of good rate design. Moreover, if some customers do value bill stability, they can voluntarily enter into a budget billing plan that achieves this end. Compelling all customers to accept (without choice) stable – but high – bills that include subsidies for other users is not a defensible Commission policy.

For these reasons, CUB and the City recommend that the Commission adopt the rate design proposal of AG-ELPC, as the most equitable, fair, and appropriate based on the facts in this record.

Peoples Fails to Justify Charging $38.50 *per* Month for the Fixed Charge

Peoples Gas proposes increasing its fixed customer charge for residential heating customers from the current $26.91 *per* month to $38.50 *per* month – a 43% increase. To state the obvious, this means that Peoples customers would pay $38.50 *per* month before using a therm of gas. Moreover, according to AG/ELPC Witness Rubin's calculations, "annual bill impacts would range from bill reductions (for a few thousand very high-use customers) to increases in excess of 30% (for the more than 30,000 customers using less than 250 therms *per* year)." Given this impact on customers, the Commission should set the bar very high in terms of what Peoples must show to justify this revenue shift.

Peoples Gas states its objective is a desire to "better align revenues with underlying costs." PGL Ex. 15.0 at 9. As the major reason for doing this Witness Egelhoff asserts, "Recovering fixed costs through a variable distribution charge sends an incorrect price signal to customers that the more gas they use the more it costs the Companies to provide them delivery services." Peoples Ex. 29.0 at 3. In essence, Ms. Egelhoff argues that Peoples wants to correct customers notion that the more gas they use, the higher the cost of service.

Peoples argues that putting "fixed cost" in a variable charge sends the wrong price signals. Its rate design moves more of the fixed cost recovery from variable charges into fixed charges. ELPC submits that this answer is nonsensical.

One thing clear from the record is that this is not about helping customers or changing customer behavior. Normally, one would expect the company to argue that if it sends customers the right message (price signal) then we can expect customers to change their behavior.

Peoples argues that fixed costs should all be recovered through fixed charges. Both AG/ELPC Witness Rubin and Staff Witness Johnson dispute the assertion that usage charges are fixed:

> A gas distribution system is designed to serve the anticipated peak demands and energy requirements of all customers. Very little if any of that investment is actually "caused" by a single customer. When we talk about the principle of cost causation, we're actually talking about a fair way to allocate shared costs among customer classes and customers.

AG/ELPC Ex. 9.0 at 2. Rubin further notes that there is a question of fairness between customer classes, because if residential customers increase their usage more of the cost of a gas main should then be transferred to that customer class. *Id.* at 3-5. Thus, you want to send the correct price signal to members of that class.

Staff witness Johnson in his testimony emphasized that long term, fixed costs increase when customers use more gas. Holding down usage, ultimately translates to a less costly system. In essence, Peoples defines fixed costs in a very narrow and inaccurate way that the facts do not support.

<u>The Commission Recently Issued a Report to the General Assembly Concluding that Rate Design Should Encourage Efficiency</u>

The issue of rate design and the Companies desire to shift revenue into fixed monthly charges is not unique to Peoples and has been a significant issue in a number of states in recent years, including Illinois. The ICC recognized the importance of this issue and addressed it directly in the ICC Report to the General Assembly Concerning Coordination Between Gas and Electric Utility Programs and Spending Limits for Gas Energy Efficiency Programs, August 30, 2013 (“Energy Efficiency Report”). The Commission reaches a conclusion that the gas companies can reach their savings targets by shifting revenue from the fixed customer charge to the volumetric charge. Report at 22. The Commission conclusion lies in direct contradiction to Peoples’ proposal in this proceeding.

The Report does an excellent job of analyzing the issue Peoples poses in this proceeding. In terms of the proper rate design moving forward, the Commission argues that revenue should be shifted back from fixed charges to volumetric charges going forward:

> The importance of these findings is that increasing the volumetric distribution charge by even 10% (the distribution charge is approximately 40%-50% of the bill) could lead to a 0.4%-0.5% short term reduction and 0.88%-1.1% long-term reduction in gas use over what it would be with the lower volumetric price19. Because altering the volumetric charge does not affect the average cost of delivery service to retail customers (it does affect the costs to individual customers but on average a customer pays the same amount), these additional savings can be achieved without increasing the budget limitations. If prices and weather are similar to what was experienced in 2009, one should expect that increasing the volumetric distribution charge by 10% would achieve a

> usage reduction that is about half of the May 31, 2015 goal of 0.8%.

Id. at 24. Hence, the Report's conclusion directly contradicts Peoples request.

The legislature's general directive is that public utilities must furnish service that protects the public, "and as shall be in all respects adequate, efficient, just, and reasonable." 220 ILCS 5/8-10.1. Read in its totality, the Public Utilities Act stresses the value of efficiency, and Ms. Egelhoff's reading that the Commission should not consider the rate design effect on efficiency contradicts the letter and spirit of the law. The legislature's point is that it has set efficiency targets that the utility should meet for the protection of Illinois customers; it did not set the targets in a vacuum and the Commission would not have taken the position that it should use rate design to affect efficiency in the Report if it believed this contradicts the Public utilities Act.

<u>Peoples Demonstrates No Revenue Issues and Decoupling Guarantees its Revenues</u>

AG/ELPC witness Rubin asserts that the main reason that a utility would need to collect more revenue through the customer charge stems from uncertainty over cost recovery that generally stems from a decline in sales. AG/ELPC Ex. 3.0 at 17. In fact the record reflects that few if any Companies have ever had greater revenue certainty, or face less risk. Rider VBA adjusts PGL's revenue collections for any changes in consumption as compared to the forecasted amount." Id at 18. Rider SSC assures Peoples it will collect all of its storage related costs, and Rider UEA guarantees Peoples will collect all of its uncollectibles. *Id.*

In addition to the revenue adjustments above, Rider QIP, approved in Docket No. 13-0554, allows Peoples to collect an immediate return on its infrastructure investments through Rider QIP. *Id.* Combined with the revenue adjustment above, Peoples has more than enough certainty without increasing its fixed charge.

<u>Peoples Fixed Charges Currently Exceed Reasonable Levels</u>

Peoples has already received a number of increases to its fixed customer charge, as this charge has increased from $9.00 *per* month in 2007 to the current $26.91 *per* month in 2014. The following table sets out the recent history:

	North Shore current	**North Shore proposed**	**Peoples Gas current**	**Peoples Gas proposed**
2007	$8.50	$16.00	$9.00	$19.00
2009	$13.50	$19.90	$15.50	$23.30
2011	$17.80	$24.75	$19.50	$28.21
2012	$22.00	$27.70	$22.25	$32.83
2014	$23.75	$29.55	$26.91	$38.50
% increase total	179% since 2007		199% since 2007	

Simple math indicates the Commission has allowed Peoples to increase its customer charge by 179% in only seven years, which raises questions about the tone of Peoples' testimony in terms of the need to correct a dire problem. In fact, the record indicates the opposite situation; the Commission has shifted too much revenue to the fixed monthly charge and it needs to reverse the trend.

Under present rates, PGL's customer charges collect approximately 62% of non-storage revenues from heating customers and 81% from non-heating customers. The proposed changes would raise those percentages to approximately 75% heating and 90% non-heating. *Id.* at 15. Instead, ELPC recommends that the ICC adjust Peoples' fixed charges consistent with the recommendations made by AG/ELPC Witness Rubin.

The exact amount of the customer charge depends on whether the Commission grants Peoples a rate increase, and if so what amount it approves. Mr. Rubin proposes a rate design that collects approximately 52% of non-storage revenue from HTG customers through customer charges and 73% from NH customers. *Id.* at 24. Based on this recommendation, even if the Commission grants Peoples its full proposed revenue increase, the HTG customer charge would remain at $26.91. If the Commission determines that Peoples has not met its burden regarding the rate increase, "[T]he rates should be scaled back proportionately so that the HTG customer charge would be designed to collect between 50% and 52% of non-storage revenues and the NH customer charge would be designed to collect approximately 73%-75% of non-storage revenues." *Id.* at 24-25. This recommendation is in line with the finding in the Commission's Report that a 10% shift of revenue from fixed charges to variable would send the correct price signals on efficiency.

Peoples Proposed Shift of Revenue to Fixed Costs is not Just and Reasonable

As set forth above, Peoples analysis regarding fixed costs fails to correctly analyze the true nature of Peoples' sunk costs in the delivery system. More than that though, Peoples' proposal violates fundamental fairness principles. As Mr. Rubin asserts, "Giving PGL's customers more control over their natural gas bills by reducing the customer charge gives customers an important incentive to reduce their energy usage." AG/ELPC Ex. 3.0 at 21. Given the legislature's desire to promote energy efficiency, the Commission should ensure that Peoples' rate design does not reduce the value of efficiency. The current customer charge of $26 *per* month already reduces customer benefits from efficiency and an increase to $38.50 speaks for itself.

The Illinois Commerce Commission recently ordered ComEd to reduce its fixed charges and increase its variable rates to better protect low-usage customers The Commission should take similar action in this proceeding as well.

Commission Analysis and Conclusion

The principal rate design issue in this case is the type of charge -- fixed or volumetric -- through which the Companies should recover non-storage demand-classified distribution costs. The Companies contend that virtually all of their costs are fixed costs which should be recovered through fixed charges---primarily the customer charge. The Companies assert that because in their analysis these costs do not vary with gas use, rate design should gradually evolve to reflect this.

The Companies argue that all demand-classified costs (*e.g.*, storage, land, structures and improvements, mains, compressor station equipment and measuring and regulating equipment) are fixed costs. The Companies contend that the costs of this type of investment do not vary with customer usage or even if the customer's demand day requirements change. In other words they seek approval for a rate design that increases the percentage of fixed costs and reduces the percentage of variable costs.

The Companies contend that SFV is merely a term describing a rate design under which all fixed costs are recovered in fixed charges. The Companies' proposed rate designs in its recent cases have moved progressively closer to an SFV rate design although they insist that they are not proposing SFV rate designs.

The Companies' revenue recovery is virtually guaranteed through the existence of Rider VBA, which acts as a decoupling mechanism for S.C. Nos. 1 and 2 and reduces the Companies' financial risk of under-recovery of revenues. In addition to Rider VBA, PGL has implemented Rider QIP, which allows PGL to recover a return of and on the Company's investment in qualifying plant, further mitigating any concern about the Companies' revenue stability. The Companies also enjoy recovery of storage costs through Rider SSC. Further, PGL is essentially guaranteed a designated level of revenues for uncollectible accounts through Rider UEA, which provides monthly adjustments to customers' bills for over or under collection of PGL's actual uncollectible expenses.

The record demonstrates that the Companies' ECOS studies take functional costs and allocate them by cost causation into commodity related, demand related, and customer related. Each class is then assigned commodity, demand, and customer related costs. Residential customers do not have demand meters. Demand related costs for classes other than residential customers are allocated based on demand, rather than the assumption that each customer contributes equally to demand. Staff and the Interveners argue the Companies' rate design would create inconsistency between how costs are caused and normally allocated and how revenues are collected for the residential classes.

The principal debate is about how the small residential service revenue requirement and the general service revenue requirement should be allocated in the absence of demand meters. The Companies' rate design, in this and prior cases, generally seeks to recover the demand costs in both fixed and variable charges, with gradual movement towards placing recovery of all of these costs as fixed charges. The Companies strongly insist that it is false that day-to-day usage causes any change to these costs. Therefore for a rate class that does not include a demand charge, a fixed charge, like the customer charge, is a better cost causal rate design than a variable charge, like the distribution charge.

The Companies' proposed SFV-based rate design shifts a greater percentage of cost recovery from a *per* therm basis to a *per* customer basis. Assigning demand related costs to the customer charge assumes each customer in the class contributes equally to the class demand. The Companies assert that it is peak demand that determines system cost and that that cost is essentially the same no matter how much or how little gas an individual customer uses. To the contrary, Staff and the Intervenors assert that there is no evidence in the record to support this assumption. They argue that usage is a reasonable proxy for demand and that demand type charges should be allocated on that basis.

Staff contends the relevant question here is not the cost of the infrastructure built to meet demand but rather who should pay for it. If demand costs are recovered through the customer charge, all customers are assumed to cost the same for the Companies to serve them. If demand costs are recovered through the distribution charge, the recovery method assumes the costs are not the same for all customers to serve them and that customers with higher usage will have higher peak demands and be more costly to serve than small use customers. As Staff notes, while this may not be true in each and every case, it is more reasonable than the Companies' proposed rate design's implied assumption that all customers within a class cause the utility to incur the same amount of demand costs.

The Companies' rationale for its design is that it allocates costs to cost causers. Staff and the Interveners argue that this is incorrect. Moreover, the net result of the Companies proposal is to reduce the effect of increased usage on the customers' bill. The Companies' rate design encourages increased consumption through lower *per* therm distribution charges. Thus, the price signal for ratepayers to conserve is weakened. Allocating these costs *per* customer, also penalizes low usage customers whose bills are higher on a *per* therm basis than high use customers.

Under the Staff and Intervenor proposals, when a customer uses more gas -- on a peak or other day -- he pays more towards demand costs, and when he uses less gas, he pays less towards demand costs.

This Commission has recognized that SFV rate designs are inconsistent with energy conservation. *See* Energy Efficiency Report. In Docket No. 13-0387, our Order adopted adjustments to ComEd's rate design in Docket No. 13-0387, which moved away from SFV-based rate design through lower fixed cost recovery. Similarly, in Docket No. 13-0476 this Commission rejected a requested increase in fixed cost recovery through a modified SFV rate design. Docket No. 13-0476, Order on Rehearing at 42 (September 30, 2014).

In Docket Nos. 12-0511 and 12-0512, this Commission ordered PGL and NS to establish separate rates and customer classes for residential heating and non-heating customers resulting in a substantial reduction in the bills for non-heating customers, due to the significantly lower demand-related costs of serving those customers.

In this case, Peoples Gas seeks to increase the heating gas customer charge from \$26.91 to \$38.50, a 43% increase. North Shore seeks to increase that charge from current \$23.75 to \$29.55, an increase of 24%.

Under present rates, PGL's customer charges collect approximately 62% of non-storage revenues from heating customers and 81% from non-heating customers. The proposed changes would raise those percentages to approximately 75% heating and 90% non-heating. *Id.* at 15.

The exact amount of the customer charge depends on the amount of the rate increase. Mr. Rubin proposes a rate design that collects approximately 52% of non-storage revenue from HTG customers through customer charges and 73% from NH customers. *Id.* at 24. Based on this recommendation, even if the Commission grants Peoples its full proposed revenue increase, the HTG customer charge would remain at $26.91.

It is patent that high customer charges mean the Companies' lowest users bear the brunt of rate increases, and subsidize the highest energy users. Steadily increasing customer charges diminish the incentives to engage in conservation and energy efficiency because a smaller portion of the bill is subject to variable usage charges and customer efforts to reduce usage.

The Commission rejects the Companies' claim that customer charges must be raised to ensure cost recovery. The Commission finds that SFV based rates that assume that non-storage demand related distribution costs should be allocated on a *per* customer basis are inconsistent with the public policies of attributing costs to cost causers, encouraging energy efficiency and eliminating inequitable cross-subsidization of high users by low users of natural gas.

Although Staff and Intervenors agree on the shift away from SFV based rates, they disagree on the percentage of fixed costs. Consistent with the more conservative rate design proposed by Staff, the Commission directs that Staff's proposed S.C. No. 1 Residential Non-Heating, S.C. No. 1 Residential Heating, and S.C. No. 2 General Service rate designs, as discussed in Sections IX.C.2.a, IX.C.2.b., and IX.C.2.c., respectively, be approved. Any increase in non-storage demand-classified distribution costs beyond the revenue provided by Staff's proposed customer charges should be collected through volumetric charges. The Commission finds that the Companies' risk of not recovering their authorized revenue requirement are minimal in light of the guaranteed revenue recovery that the Companies enjoy through decoupling, uncollectibles and infrastructure riders.

C. Service Classification Rate Design

1. Uncontested Issues

a. Service Classification No. 8, Compressed Natural Gas Service (PGL)

<u>Companies' Position</u>

Peoples Gas proposed to set S.C. No. 8, Compressed Natural Gas Service, at cost. PGL Ex. 15.0 REV. at 10. North Shore does not have a comparable service classification.

<u>Staff's Position</u>

North Shore does not currently have a Compressed Natural Gas Service class. Peoples Gas is proposing to set the S.C. No. 8 Compressed Natural Gas Service class at cost. PGL Ex. 15.0 at 19. Seventy-five percent of total customer costs are recovered through the customer charge under the Company's proposal compared to the current

50%. The Company is taking a gradual approach for bill impact reasons. Staff Ex. 4.0, 62. The revenues in total from all charges will recover the full cost to serve the customers. The S.C. No. 8 class is available to any customer for gas to be used as compressed natural gas to fuel a vehicle. *Id.*

Staff has no objection to Peoples Gas' rate design proposal for the S.C. No. 8 rate class. Staff opined that it is important that the S.C. No. 8 rates reflect the full class cost of service so customers can make informed decisions concerning their use of natural gas in vehicles and their possible purchases of natural gas vehicles. Id. at 63. No other party provided written testimony addressing the S.C. No. 8 class.

Commission Analysis and Conclusion

The Commission finds that Peoples Gas' rate design for its compressed natural gas service classification is appropriate and reasonable. It is proper to set this service classification at cost. The proposal is uncontested. The Commission approves Peoples Gas' proposed S.C. No. 8 rate design.

b. S.C. No. 5 Contract Service for Electric Generation and S. C. No. 7 Contract Service to Prevent Bypass

North Shore and Peoples Gas proposed no changes to S.C. Nos. 5 and 7, and they exclude these classes from consideration because the revenues from these customers are based on negotiated rates rather than the ECOSSs. NS Ex. 15.0 at 8 9, 19; PGL Ex. 15.0 REV. at 8-9, 19.

The Commission finds that the Companies' proposals not to revise these service classifications are appropriate and reasonable. The proposals are uncontested. The Commission approves no changes to S.C. Nos. 5 and 7.

2. Contested Issues- North Shore and People Gas

a. Service Classification No. 1, Small Residential Service, Non-Heating

Companies' Position

The Companies stated that, consistent with the rate design objectives and principles applicable to fixed cost recovery, they each proposed to continue to set S.C. No. 1 NH at cost. NS Ex. 15.0 at 10; PGL Ex. 15.0 REV. at 10. North Shore and Peoples Gas each proposed to recover 90% of non-storage related fixed costs through the customer charge with all remaining non-storage costs being recovered through a flat distribution charge. Each would continue to recover storage-related costs under Rider SSC. NS Ex. 15.0 at 11; PGL Ex. 15.0 REV. at 11. The Companies contend that their proposals are consistent with the Commission policy for gas Companies of gradually increasing fixed cost recovery in fixed charges. To retreat from this gradual movement, as AG/ELPC and potentially Staff proposed, exacerbates the extent to which a customer's bill does not reflect the costs it causes the Companies to incur. The Companies also stated that the IIEC's flawed across-the-board increase should be rejected.

Staff's Position

The Commission should have the Companies begin the process of moving away from SFV-based rate design. By assuring that the S.C. 1 NH class' customer charge reflects ECOS study-based customer costs only, the Commission can start the movement away from SFV-based rates for North Shore and Peoples Gas and ensure that customers are instead paying for the ECOS study-based costs they cause.

The Companies propose fixed customer charges for North Shore and Peoples Gas that recover 90% of non-storage related fixed costs through the customer charge. The Companies also propose a flat distribution charge *per* therm for sales and transportation customers. NS Ex. 15.0 at 11; PGL Ex. 15.0REV at 11.

Staff witness Johnson found that the Companies' total customer charge revenues derived from their proposed customer charges reflect approximately 97% of the total ECOS study-based customer costs for the Companies. Therefore, under the Companies' proposal, customers in the S.C. No. 1 NH class would pay for ECOS study-based customer costs in the customer charge and ECOS study-based demand costs in the single block distribution charge. This methodology is consistent with the rate design the Commission approved for ComEd in Docket No. 13-0387 and favored in Ameren Docket No. 13-0476. Therefore, Staff witness Johnson has no objection to the proposed customer charge and flat distribution charge recommended by the Companies. They both recover their individual ECOS study-based costs. Staff Ex. 4.0, 26-27, 45.

However, Mr. Johnson's agreement with the Companies' proposed customer charge and flat distribution charge is not an acceptance of the Companies' theory for their proposed SFV-based rate design with 90% fixed cost recovery. If North Shore's total customer charge revenues derived from the proposed customer charge ($15.80) are greater than the customer costs found on the final Commission approved ECOS study in this proceeding, then the final customer charge should be lowered to recover ECOS study-based customer costs only. Likewise if Peoples Gas' total customer charge revenues derived from the proposed customer charge ($16.70) are greater than the customer costs found on the final Commission approved ECOS study in this proceeding, then the final customer charge should be lowered to recover ECOS study customer costs only. Any remaining revenues for either Company would be collected through the flat distribution charge. *Id.* at 27. Staff's proposed rates, which are based upon the Companies' proposed direct testimony revenue requirement (Staff Ex. 4.0 at 24.), can be found at Staff Ex. 4.0, Schedule 4.01N and Schedule 4.01P.

In rebuttal testimony, the Companies opposed Staff's conditional approval that the Companies' total customer charge revenues derived under the Companies' proposed rate designs and the final Commission approved ECOS studies should not result in more than customer cost recovery through the customer charge. Companies witness Egelhoff stated that all of the Companies' costs recovered through base rates are fixed. NS-PGL Ex. 29.0 REV at 15.

Staff witness Johnson responded that the Companies' position reflects the overall disagreement on whether the customer charge should recover only customer costs (traditional rate design) or include costs related to customer demands (100% SFV or SFV-based). As Staff discussed in direct testimony, the Commission is moving away from an SFV-based rate design and back to a more traditional rate design approach, *i.e.*, all demand-related costs are recovered through the variable charge and all customer-related costs are recovered through fixed charges. The Commission's recent Orders make it clear that SFV-based rate designs should be re-examined and rates should reflect traditional rate design principles, which more closely align customers' bills with the ECOS study. Docket No. 13-0387, Order at 75; Docket No. 13-0476, Order at 101 (March 19, 2014); Staff Ex. 9.0 at 12.

Staff witness Johnson opined that a traditional rate design approach more closely aligns rates with cost causation principles. As discussed under the Fixed Cost Recovery section above, if demand costs are recovered through the customer charge, all customers are assumed to cost the same to serve. If demand costs are recovered through the distribution charge, the cost to serve each customer is based upon usage. While both cost recovery methods are not exact, recovering demand costs through the distribution charge takes into consideration that customers do place different costs on the system. *Id.*

AG's Position

Peoples Gas and North Shore propose to substantially increase the customer charges for both heating ("HTG") and non-heating ("NH") customers and to reduce the *per*-therm distribution charges for both classes. In particular, Peoples Gas proposes the rate increases for Non-heating Residential customers as shown in the following tables:

PGL Rate	**Present**	**PGL Proposed**	**% Increase**
NH customer charge	$13.60	$16.70	+ 22.8%
NH volumetric charge (including VBA)	$0.43626	$0.24087	- 44.8%

North Shore Rate	**Present**	**PGL Proposed**	**% Increase**
NH customer charge	$13.65	$15.80	+ 15.8%
NH volumetric charge (including VBA)	$0.27292	$0.13748	- 49.6%

AG/ELPC Ex. 3.0 at 14, 25. Under present rates, PGL's Non-Heating customer charges collect approximately 81% of non-storage revenues. For North Shore, the Company's Non-Heating customer charges under present rates recover 80% (NH) of non-storage revenues. The proposed rate changes would increase those percentages to approximately 90% for both Companies.

AG/ELPC rate design witness Scott Rubin analyzed the Companies rate design and found it lacking in many regards. First, the Companies own cost studies reveal that there are significant demand –related costs, that is, costs that are impacted by customer demand for natural gas. Such costs should never be recovered through fixed customer charges. AG/ELPC Ex. 3.0 at 15. Mr. Rubin's uncontested analysis for PGL's NH customer class shows that approximately 7% of the cost of serving the class is demand-related. AG/ELPC Ex. 3.0 at 16. This means that 93% of the NH cost of service is customer related. Again, this is the theoretical maximum amount that should be collected through the NH customer charge. For North Shore, approximately 7% of the cost of serving the Non-Heating Residential class is demand-related. This means that 93% of the NG cost of service should be collected through the Non-Heating customer charge. AG/ELPC Ex. 3.0 at 27.

Using PGL's actual billing data for the test year, Mr. Rubin determined that the range of impacts is very diverse – and unwarranted – for the Companies' NH customers. As shown on AG/ELPC Ex. 3.3, the impacts range from annual increases approaching 20% (customers using 25 therms or less *per* year) to sizeable bill reductions for those customers using more than 200 therms *per* year. AG/ELPC Ex. 3.0 at 22. Once again, validating the classification of higher-use NH customers might eliminate some of these bill reductions, but there will remain customers at the high end of the class whose annual bills would be lower under PGL's rate design than they are now, even though PGL is proposing nearly a 10% increase in revenues collected from the NH class.

For NS NH customers, the impacts range from annual increases approaching 15% (customers using 25 therms or less *per* year) to sizeable bill reductions for those customers using more than 200 therms *per* year. *Id.* at 28. Once again, validating the classification of higher-use NH customers might eliminate some of these bill reductions, but there will remain customers at the high end of the class whose annual bills would be lower under the NS rate design than they are now.

To remedy these cross-subsidization inequities between low and high users, Mr. Rubin recommended that PGL and NS should move toward collecting no more than 75% of their respective Non-Heating class revenues, from the customer charges. Under the Companies' proposed revenue requirements, Mr. Rubin's proposed rate design would collect approximately 73% of PGL Non-Heating (non-storage) revenues and 78% of North Shore Non-Heating revenues through the customer charges. This change will start the process of restoring the Companies' residential customer charges to more traditional levels. Further, Mr. Rubin's proposals will rationalize the rate design, consistent with the Companies' own cost studies, give customers more control over their bills (thereby ensuring consistency with the State's energy efficiency goals), and start to alleviate some of the impacts of the rate design on low-income customers that AG witness Colton discusses in his testimony. His proposed rates are:

Rate	**Present**	**AG/ELPC Proposed**	**% Increase**
PGL NH customer charge	$13.60	$13.60	0.0%
PGL NH volumetric charge (including VBA)	$0.43626	$0.64901	+ 48.8%
NS NH customer charge	$13.65	$13.65	0.0%
NS NH volumetric charge (including VBA)	$0.27292	$0.30634	+ 21.5%

AG/ELPC Ex. 3.0 at 24, 29. Again, assuming 100% recover of PGL's proposed revenue requirement, the AG/ELPC-proposed rate design would collect approximately 73% of PGL's Non-Heating non-storage revenues and 78% of North Shore Non-Heating non-storage revenues through the customer charges. *Id.* at 24, 30. If approved, this change would start the process of restoring PGL's residential customer charges to more traditional levels.

In the very likely possibility that the Commission determines that Peoples Gas should receive a lower rate increase than Peoples Gas requested, the rates shown in the above table should be scaled back proportionately so that the PGL Non-Heating customer charge would be designed to collect approximately 73% to 75% of non-storage revenues, and the NS Non-Heating customer charge would collect approximately 75% to 78% of non-storage revenues.

Coupled with the approval of the AG/ELPC proposed Residential Heating rate design discussed below, these rates will rationalize the Companies' overall Residential rate design, give customers more control over their bills (thereby ensuring consistency with the State's energy efficiency goals), and start to alleviate some of the impacts of the modified SFV rate design approved to date by the Commission has had on low-income customers that AG witness Colton discusses in his testimony. The policy reasons that support Mr. Rubin's proposed Non-Heating rate design related to the Company's lack of risk in revenue recovery are further discussed below in the Residential Heating section of the Brief below, and will not be repeated here.

AG/ELPC witness Rubin is proposing that PGL and NS move toward collecting no more than 50% of its heating revenues, and no more than 75% of its non-heating revenues from the customer charges. AG/ELPC Ex. 3.0 at 22, 29. Mr. Rubin states that under PGL's proposed revenue requirement, the 50% and 75% results can be approximated by keeping PGL's heating and non-heating customer charges at their existing amount. Thus, the increase would be collected solely through increases in the volumetric charges. *Id.* at 22.

For NS, Mr. Rubin states that under North Shore's proposed revenue requirement the effects on larger-use heating customers might be severe if the change were made in one step, so Mr. Rubin recommends the residential customer charges should remain at their existing amounts. *Id.* at 29.

Mr. Rubin's proposed Non-Heating Residential rate design, should be adopted by the Commission.

<u>Commission Analysis and Conclusion</u>

The Commission finds that the Companies' proposed increases in the customer charges pursuant to its SFV based rate design are inconsistent with public policy as discussed in Section IX, B 2 (Fixed Cost Recovery) of this order. The Commission finds that IIEC's proposal for an across the board increase in rates is not supported by the evidence. Staff's proposal to move away from SFV based rates is reasonable and supported by the record

The Commission accepts Staff's rate design proposal for this customer class, which reflects a more traditional rate design whereby customer charges recover embedded cost-of-service ("ECOS") study customer costs and distribution charges recover ECOS study demand costs. Therefore, customer's bills are more closely aligned with the ECOS study. The customer charges for the S.C. No. 1 Small Residential Service, Non-Heating class should be set to recover the final Commission approved ECOS studies' customer costs. The remaining, non-storage related demand costs, would be recovered through a flat distribution charge on a per therm basis.

b. Service Classification No. 1, Small Residential Service, Heating

Companies' Position

The Companies stated that, consistent with the rate design objectives and principles applicable to fixed cost recovery, they each proposed to continue to set S.C. No. 1 HTG at cost. NS Ex. 15.0 at 10; PGL Ex. 15.0 REV. at 10. North Shore proposed to recover 80% and Peoples Gas proposed to recovery 75% of non-storage related fixed costs through the customer charge with all remaining non-storage costs being recovered through a flat distribution charge. Each would continue to recover storage-related costs under Rider SSC. NS Ex. 15.0 at 12; PGL Ex. 15.0 REV. at 12. The Companies contend that their proposals are consistent with the Commission policy for gas companies of gradually increasing fixed cost recovery in fixed charges. To retreat from this gradual movement, as AG/ELPC and Staff proposed, exacerbates the extent to which a customer's bill does not reflect the costs it causes the Companies to incur, *i.e.*, customer usage would drive fixed cost recovery but usage does not drive the Companies' incurrence of those fixed costs.

Staff Position

Staff urges the Commission to accept Staff's proposal to set the S.C. No. 1 Heating classes' customer charges to recover ECOS study customer costs and set distribution charges to recover ECOS study demand costs.

North Shore is proposing to increase the recovery of fixed costs in its SFV-based rate design to recover 80% of non-storage related fixed costs through the customer charge, compared to the current 68% fixed cost recovery, with all remaining costs being recovered through a flat distribution charge. The monthly customer charge would increase from $23.75 to $29.55 and the distribution charge would decrease from 10.385 cents *per* therm to 7.133 cents *per* therm. This is applicable to both sales and transportation customers. NS Ex. 15.4. Peoples Gas is proposing to increase the recovery of fixed costs in its SFV-based rate design to recover 75% of non-storage related fixed costs through the customer charge, compared to the current 61% fixed cost recovery, with all remaining costs being recovered through a flat distribution charge. The monthly customer charge would increase from $26.91 to $38.50 and the distribution charge would decrease from 18.885 cents *per* therm to 14.919 cents *per* therm. This is applicable to both sales and transportation customers. PGL Ex. 15.4.

Staff witness Johnson's assessment of the Companies proposal found that North Shore's proposed customer charge would recover approximately $51,355,507 in total annual customer charge revenues while the ECOS study identifies only $43,452,183 in customer costs for the S.C. No.1 HTG class. He found Peoples Gas' proposed customer charge would recover approximately $303,291,027 in total annual customer charge revenues while the ECOS study identifies only $254,928,725 in customer costs for the S.C. No.1 HTG class. Staff Ex. 4.0 at 28. Mr. Johnson opined that these proposals are inconsistent with the Commission's recent orders, which adopt rate designs that move away from an SFV-based rate design and instead align customers' bills with the cost of service (*i.e.*, customer charges based upon ECOS study customer costs and distribution\demand charges based upon ECOS study demand costs). *Id.* at 29. Staff's proposed rate design which sets customer charges based upon ECOS study customer costs and distribution charges based upon ECOS study demand costs would consist of a $25 monthly customer charge and 11.544 cents *per* them distribution charge for North Shore and a $32.35 monthly customer charge and 22.063 cents *per* therm distribution charge for Peoples Gas. NS-PGL Ex. 29.0 REV at 17-18. Staff's proposed rates are based upon the Companies' proposed direct testimony revenue requirement. Staff Ex. 4.0 at 24.

Moreover, Staff found that because the Companies' proposed customer charges are based upon all ECOS study customer costs and part of the demand costs, the resulting lower distribution charge results in those customers that are incurring greater demands on the system to not paying their fair share. This occurs because under the Companies' proposal, demand costs are recovered through the customer charge, thereby shifting cost recovery from a *per* therm basis to a *per* customer basis. The lower-use heating customers in effect would subsidize the larger-use heating customers.

Finally, in order to reflect the proper price signal and encourage energy conservation, the distribution charge should reflect all demand related costs so that those customers who place greater demands on the system pay for those demands.

In the rebuttal stage of this proceeding the Companies stated that all of their costs recovered through base rates are fixed and that the cost of having infrastructure in place to handle that demand does not vary based on a customer's use. NS-PGL Ex. 29.0 REV at 17.

Recent Commission Orders indicate a movement away from SFV-based rate designs, especially for those Companies with cost recovery mechanisms in place (like the Companies' Rider VBA) that provide revenue stability. Staff's rate design proposal makes a similar movement while taking rate impacts into consideration. Staff Ex. 9.0 at 14.

AG/ELPC witness Rubin is proposing that PGL and NS move toward collecting no more than 50% of its heating revenues, and no more than 75% of its non-heating revenues from the customer charges. Mr. Rubin states that under PGL's proposed revenue requirement, the 50% and 75% results can be approximated by keeping PGL's heating and non-heating customer charges at their existing amount. Thus, the increase would be collected solely through increases in the volumetric charges. *Id.* at 22.

For NS, Mr. Rubin states that under North Shore's proposed revenue requirement the effects on larger-use heating customers might be severe if the change were made in one step, so Mr. Rubin recommends the residential customer charges should remain at their existing amounts. *Id.* at 29.

Staff witness Johnson stated that it is not clear how Mr. Rubin derived the percentages of 50% and 75% for heating and non-heating, respectively. Mr. Rubin states that PGL's ECOS study shows that 64% of heating costs are customer related and 93% of non-heating costs are customer related. *Id.* at 16. He also states that NS' ECOS study shows that 67% of heating costs are customer related and 93% of non-heating costs are customer related. *Id.* at 27. He emphasizes that these are the maximum amount of costs that should be collected through the customer charge because the percentages from the ECOS studies assume that it is proper to recover all distribution-related costs that are classified as customer-related through the customer charge. He argues that traditionally NS and PGL collected a portion of those customer-related distribution costs through a volumetric charge. *Id.* at 16, 26-27. Staff argues that Mr. Rubin has not provided any type of evidence to justify that the distribution-related costs that are classified as customer-related should just be classified as distribution-related. Staff Ex. 9.0 at 24.

Staff also stated that it is also not clear whether the 50% and 75% figures are based upon Mr. Rubin's assumption that the ECOS study distribution-related costs recovered through the customer charge should be recovered through the volumetric charge or are based upon some other reason. Therefore, Staff witness Johnson stated that he continues to recommend that the Commission accept Staff's rate design proposal as set forth in direct testimony. *Id.*

<u>AG's Position</u>

As noted by AG/ELPC witness Rubin, the Companies' proposed changes to residential heating rates, in particular, are inequitable and inconsistent with both the Companies' own cost studies and public policy goals related to conservation and energy efficiency. As noted in the Rate Design Overview section above, Peoples Gas and North Shore residential heating customer charges have risen by nearly 200% and 179%, respectively, since 2007, the year PGL/NS began filing a steady stream of rate cases under its new parent company, Integrys, and are the highest in the state by a long shot. Both PGL and NS want to increase the amount of revenue they receive from customers through non-variable charges. Peoples Gas is proposing to increase its Heating revenues recovered in this case by another 17.3%, but proposes an increase in the PGL customer charge of 43.1%.

Under present rates, PGL's residential Heating customer charges collect approximately 62% (HTG) of non-storage revenues. The proposed rate changes would increase those PGL percentages to approximately 75% (HTG). *Id.* at 15.

Similarly, North Shore seeks to increase its overall Heating revenues by 5.2%, but increase the NS customer charges by more than 24%. AG/ELPC Ex. 3.0 at 25. Under present rates North Shore collects approximately 68% of non-storage revenues through the customer charge. The proposed North Shore rate changes would increase this percentage to approximately 80% (HTG) for North Shore customers

The proposed changes are significant and would result in customer bill impacts being very different from the class average rate increase. Specifically, low-use customers would see much greater than average increases, while high-use customers would have increases much lower than average, and in some cases even decreases in their total distribution bill. AG/ELPC Ex. 3.0 at 15, 25. As Mr. Rubin explained, PGL's proposals are not consistent with either sound rate design principles or reasonable cost-of-service principles.

First, as Mr. Rubin noted, a significant portion of the cost of serving heating customers is demand-related costs. In classes that have demand meters, demand-related costs are collected from customers in proportion to each customer's actual demand. In classes without demand meters (like the residential classes), however, the fairest way to recover those demand-related costs is in proportion to a customer's usage of gas. For the PGL HTG class, the cost-of-service study shows that 37% of the non-storage cost of service is demand-related. This means that, under PGL's own cost-of-service study, there is no justification for collecting more than 63% of the cost of service through the customer charge. PGL's existing rates already recover 62% of residential revenues through the customer charge, so there is no justification for a substantial increase in that charge. *Id.* at 15-16. For the NS HTG class, the cost-of-service study shows that 33% of the non-storage cost of service is demand-related. This means that, under North Shore's own cost-of-service study, there is no justification for collecting more than 67% of the cost of service through the customer charge. North Shore's existing rates already recover 68% of residential revenues through the customer charge, so there is no justification for a substantial increase in that charge.

Moreover, the percentages from the cost-of-service study assume that it is proper to recover all distribution-related costs that are classified as customer-related through the customer charge. Traditionally, PGL (and many other gas companies) collected a portion of those customer-related distribution costs. Thus, based on PGL's own cost study, 63% would be the maximum theoretical amount of cost that should be collected through the customer charge for HTG customers. *Id.* at 16. When viewed through facts specific to this case, such as the Companies' guarantee that it will recover its revenue requirement through Rider VBA and other previously identified riders, as well as public policy goals that seek to encourage conservation and energy efficiency, even this 63% level is excessive.

Public Policy Goals Support Rejection of the NS/PGL Rate Design Proposals.

Of course, the Companies have made no secret of why they seek to recover more revenues through the Residential customer charge. When a utility's sales are declining, as appears to be the case with PGL now (at least based on its forecasted test year data), the utility would like to collect more of its revenues through the flat, non-usage based customer charge. Conversely, when a utility's sales are increasing – as was the case for PGL and many gas Companies for several decades -- the utility prefers to have more revenues collected through volumetric charges. Moreover, because natural gas usage is primarily weather-sensitive, the Companies seek to eliminate risk by ensuring a consistent amount of revenues through the flat monthly customer charge. *Id.* at 17. Past Commission orders have responded to utility company claims that revenue stabilization is needed through ever-increasing customer charges. Recently, the Commission has begun to re-think that policy. In the recent Commonwealth Edison Company rate design proceeding, for example, the Commission rolled back the amount of revenues recovered through the customer charge for ComEd, noting in particular that because there is little risk of non-recovery of costs for ComEd because of its adoption of formula rates, a lowering of the percentage of revenues recovered through the customer charge was justified.

In the instant docket, PGL and North Shore have virtually no risk of not recovering their respective revenue requirements going forward. The Companies have three rate mechanisms in place that essentially assure PGL that it will recover approximately the same annual level of residential revenues each year. Rider VBA adjusts PGL's revenue collections for any changes in consumption as compared to the forecasted amount. This is achieved through an annual reconciliation that ensures that the Company receives the revenue requirement for the residential and small commercial customer classes (the vast majority of its customer base) that was established in the last rate case. That is, if revenues in a given class fall below the previously established revenue requirement set by the Commission, surcharges are assessed through Rider VBA in April through December of the following year.

Similarly, Rider SSC essentially assures Peoples Gas that it will collect its storage-related costs, not only by adjusting for actual vs. projected payments for storage within the residential customer class, but even permitting the shifting of costs among classes for differences in storage utilization. *Id.* at 18. In addition, the Company is essentially guaranteed a designated level of revenues for uncollectible accounts through Rider UEA. This rider provides for monthly adjustments to customers' bills for any over- or under-collections of PGL's actual uncollectible accounts expense. *Id.*

The Companies also have begun implementing a new monthly revenue adjustment mechanism called Rider QIP. PGL's Rider QIP was approved by the Commission's final Order in Docket No. 13-0534 and became effective January 1, 2014. Rider QIP allows PGL (and North Shore) to collect a return of and on qualifying infrastructure investments, as defined in new Section 9-220.3 of the Public Utilities Act.

This new rider will ensure that PGL's costs for new distribution facilities in its AMRP program are collected from customers as the facilities are completed, rather than having to wait for the filing and completion of a new distribution rate case. *Id.* at 18-19.

The existence of all of these ratemaking mechanisms are important because they remove any concerns Peoples Gas and North Shore otherwise may have with revenue stability. There simply is no need to have high customer charges to enhance annual revenue stability when Riders VBA, SSC, UEA, and QIP already provide the Companies with those assurances. This revenue stability is consistent with the Commission's recent finding in the aforementioned ComEd rate design case.

Other state commissions have considered the amount of risk of revenue recovery in assessing the need for high customer charges. Mr. Rubin noted that the Minnesota Public utilities Commission assessed revenue recovery risk when considering a revenue decoupling mechanism (like Rider VBA) and the residential customer charge for another natural gas utility. In *CenterPoint Energy Resources,* Docket No. G-008/GR-13-316 (Minn. PUC June 9, 2014), that commission rejected the utility's request for a large increase in the customer charge (from $8.00 to $12.00) and set the customer charge at $9.50 for all residential customers (heating and non-heating). That commission stated: "full revenue decoupling achieves a revenue-stabilization objective that might otherwise be accomplished by an increased customer charge. Both effectively reduce revenue volatility for the Company, protecting its ability to recover fixed costs from unexpected usage variations caused by weather or other factors. Given the protection provided by revenue decoupling, the Commission will not approve the Company's proposed increase …" *Id.* at 51.

The ICC, too, has also recognized that Rider VBA and high fixed charges are redundant ways to address the issue of revenue stability. In its August 30, 2013 Energy Efficiency Report, the Commission stated that because of Rider VBA, "the Commission can provide a mechanism for revenue stability that lowers the monthly customer charges and increases the volumetric charges. Such a change can decrease energy use by providing a greater price signal" to customers. In other words, because of the various adjustment riders in PGL's tariff, it is no longer necessary (assuming for the sake of argument that it ever was necessary) for PGL to have high customer charges. The issue of revenue stability is addressed through the riders; it does not need to be addressed again through the rate design. AG/ELPC Ex. 3.0 at 20.

Other policy implications should be considered by the Commission when examining the customer charge issue in this case. The Illinois General Assembly, in its passage of Section 8-104 of the Public utilities Act, made clear its interest in reducing the amount of natural gas delivered to utility customers and reducing the cost of utility bills that customers pay. Specifically, Section 8-104(c) requires specific reductions in the use of natural gas on an annual basis. As AG/ELPC witness Rubin aptly testified, moving even closer to SFV rates, as Peoples Gas proposes, undermines this public policy objective by reducing the amount of the customer bill that can be reduced through conservation and energy efficiency. AG/ELPC Ex. 3.0 at 20. Giving PGL's customers more control over their natural gas bills by reducing the customer charge gives customers an important incentive to reduce energy usage.

In the aforementioned ICC Energy Efficiency Report, the Commission recognized that moving away from SFV rates could help the State meet its energy efficiency goals. The Commission, in particular, recognized that reducing the customer charge while increasing variable charges could reduce overall natural gas usage and assist in the achievement of statutory natural gas usage reduction goals in a cost-effective manner. The Commission stated:

> The importance of these findings is that increasing the volumetric distribution charge by even 10% (the distribution charge is approximately 40%-50% of the bill) could lead to a 0.4%-0.5% short term reduction and 0.88%-1.1% long-term reduction in gas use over what it would be with the lower volumetric price. Because altering the volumetric charge does not affect the average cost of delivery service to retail customers (it does affect the costs to individual customers but on average a customer pays the same amount), these

> additional savings can be achieved without increasing the [energy efficiency program] budget limitations. If prices and weather are similar to what was experienced in 2009, one should expect that increasing the volumetric distribution charge by 10% would achieve a usage reduction that is about half of the May 31, 2015 goal of 0.8%.

Id. at 24. Thus, the Commission agreed that enabling customers to have more control over their natural gas bills serves the statutory goal of reducing natural gas consumption in a cost-effective manner.

The Companies' Rate Design Proposals Result in Inequitable Cross-Subsidies

As noted by AG witness Rubin, the Companies' proposed rate design would further shift the burden of revenue collections onto low-use residential customers – an inequity that the Commission has sought to eliminate in recent orders. In discovery, the Companies provided Mr. Rubin with actual billing data for each month of the test year for each of its residential customers. The data set consists of more than 7 million records for Peoples Gas and more than 1 million records for North Shore. AG/ELPC Ex. 3.0 at 4. Using PGL's actual billing data for the test year, Mr. Rubin determined that for Heating customers, annual bill impacts would range from bill reductions (for a few thousand very high-use customers) to increases in excess of 30% (for the more than 30,000 customers using less than 250 therms *per* year). While some of the impacts for very low-use customers might be eliminated if those customers turned out to be Non-Heating customers, there would remain increases in the range of 25% or more for tens of thousands of customers using between 250 and 750 therms *per* year.

The impacts for NS Heating customers are similar to those observed for Peoples Gas. Using North Shore's actual billing data for the historical 2012-2013 year, Mr. Rubin determined that for HTG customers, annual bill impacts would range from bill reductions for more than 24,000 customers (about one in every five customers) to increases in excess of 15% (for the more than 7,000 customers using less than 500 therms *per* year). While some of the impacts for very low-use customers would be eliminated if those customers were NH customers, there would remain increases in the range of 25% for PGL Heating customers and 10% or more North Shore customers for tens of thousands of customers using between 250 and 750 therms *per* year. AG/ELPC Ex. 3.0 at 22, 28.

Roger Colton, a lawyer and economist who has analyzed the impact of utility rates on low-income customers for state agencies, federal agencies and private Companies for more than 20 years, offered testimony on the impact of the North Shore and Peoples Gas rate increase proposals on low-use ratepayers, particularly their effect on low-income gas customers.

Colton's testimony examines the impact on low-use ratepayers of North Shore's proposal to increase its fixed monthly customer charge by 24% and Peoples' plan to increase its own customer charge by 43%, as well as the unfairness of the rate design plans proposed by each utility, which compel low-use customers to subsidize high-use customers. He recommends that both of these proposals be rejected as unreasonable given that these charges impose disproportionate risks on segments of the Companies' customer base that on average use far less gas than other customers and thereby place far less demand on North Shore's and Peoples' gas delivery systems. He proposes that the Commission instead approve the cost-based rate design proposed by AG witness Scott Rubin (AG/ELPC Ex. 3.0) and reduce the monthly customer charge, rejecting the Straight-Fixed Variable rates that have unfairly allocated North Shore's and Peoples' delivery costs and thwarted consumers attempts to control their electric bills.

Colton makes these recommendations in view of statements made by the Companies to the investment community that their financial condition is far more secure than has been represented to this Commission. AG Ex. 4.0 at 31-32. In light of those claims, Colton explains how the need to balance the interests of ratepayers and utility shareholders dictates that low-use customers should not be forced to bear the normal operating and financial risks faced by public utility companies, either through an unfair rate structure or through the recovery of questionable or excessive utility costs. AG Ex. 4.0 at 32-33.

Colton first reports on the fact that the fixed monthly customer charges imposed on North Shore and Peoples ratepayers are outliers in the Illinois utility industry, as noted earlier in this portion of the Brief. Even at current rates, North Shore and Peoples have the highest customer charges in the state of Illinois, at $23.75 and $26.91 respectively. A customer of one of these Companies is being asked to spend these amounts even if they do not consume a single therm of natural gas. AG Ex. 4.0 at 5-6.

AG witness Colton noted that fixed customer charges of this size, combined with the Companies' regressive rate design, impose disproportionately higher percentage increases on low-use customers. Peoples' residential non-heating customer bills will be impacted in inverse proportion to how much gas they use:

PGL Non-Heating Customers,

% Ave. Consumption	Effective Increase	Average Annual Dollar Impact
50%	+7.6%	+$16.80
75%	+5.0%	+$12.19
150%	-0.6%	- $ 1.74

Similarly, Peoples residential heating customers are more burdened by the Company's proposal if they use less gas:

PGL Heating Customers,

% Ave. Consumption	Effective Increase	Average Annual Dollar Impact
25%	+19.2%	+$103.24
50%	+12.2%	+$89.44
150%	+2.3%	+$34.19

The same relationships hold under the North Shore proposal:

NS Non-Heating Customers,

% Ave. Consumption	Effective Increase	Average Annual Dollar Impact
25%	+11.1%	$21.71

50%	+7.8%	$17.69
150%	+0.4%	$ 1.35

NS Heating Customers,

% Ave. Consumption	Effective Increase	Average Annual Dollar Impact
25%	+12.3%	$59.71
50%	+7.2%	$49.84
150%	+0.7%	$10.34

The effective result of these regressive proposals is that non-heating customers with one-sixth the consumption of higher use customers (25% vs. 150%) will pay multiple times more in absolute dollars on an annual basis. Heating customers with one-sixth the consumption of higher use customers (25% vs. 150%) will pay not just more in absolute dollars annually, but multiple times more. AG Ex. 4.0 at 9.

The impact of these pricing structures on low-income customers, Colton observes, is particularly egregious. Low-income customers tend to be, in general, low-use customers, because low-income customers tend to live in substantially smaller housing units than do higher income customers. Colton presented data from the U.S. Department of Energy's 2009 Residential Energy Consumption Survey for the Midwest Census region, which includes Illinois, showing that natural gas consumption increases as income increases, and that higher incomes lead to occupation of larger sizes of housing units. AG Ex. 4.0 at 11-12; AG Ex. 4.1, RDC-5, p.1-3.

Colton's ultimate conclusion is that the Companies' proposed rates and rate designs, if adopted by the Commission, will have a disproportionate impact on low-use customers, many of whom tend to be low-income customers as well, not only because they will absorb a higher percentage of the proposed rate increases the less they consume, but also because they will pay more in absolute dollars. Mr. Colton's findings are yet another reason why the Companies' Residential Rate Design proposals should be rejected.

AG/ELPC Witness Rubin's Rate Design Should Be Adopted by the Commission

To remedy cross-subsidization inequities between low and high users, Mr. Rubin recommended that PGL should move toward collecting no more than 50% of HTG revenues from the customer charges. Under PGL's proposed revenue requirement, these results can be approximated by keeping PGL's customer charges at their existing amounts. Thus, the increase in PGL's proposed increases in the HTG and NH revenue requirements would be collected solely through increases in the volumetric charges.

Mr. Rubin calculated the impact on customer rates of the AG-proposed rates, as is described on AG/ELPC Exhibit 3.3 and 3.4. It can be seen that lower-use customers in each class receive modest rate increases, while those customers who use more gas see greater impacts on their bills, consistent with cost-causation principles.

Again, assuming 100% recover of the Companies' proposed revenue requirements, the AG/ELPC-proposed rate design would collect approximately 52% of PGL's Heating non-storage revenues and 64% of North Shore's Heating non-storage revenues through the customer charges. If approved, this change would start the process of restoring PGL's residential customer charges to more traditional levels. Similar to what was proposed in the Residential Non-Heating section above, in the very likely possibility that the Commission determines that Peoples Gas should receive a lower rate increase than Peoples Gas requested, the rates shown in the above table should be scaled back proportionately so that the HTG customer charge would be designed to collect between approximately 50% and 52% of non-storage revenues for PGL Heating customers and approximately 64% of non-storage revenues for North Shore Heating customers. Approval of the AG/ELPC proposed rate design will rationalize the rate design, give customers more control over their bills (thereby ensuring consistency with the State's energy efficiency goals), and start to alleviate some of the impacts of modified SFV rate design that has been approved to date by the Commission has had on low-income customers that AG witness Colton discusses in his testimony. It should be adopted by the Commission.

The Companies' Criticisms of AG/ELPC Witness Rubin's Proposed Rate Design Should Be Rejected by the Commission

In her Rebuttal testimony, Ms. Egelhoff claims that SFV pricing "sends the most accurate price signals about the cost of delivery service" to customers NS-PGL Ex. 29.0 at 3. The Companies are wrong on that point. As noted by AG witness Rubin, SFV pricing, and other pricing schemes that move toward SFV pricing like the Companies' proposals in this case, fail to send customers an accurate signal about the costs associated with serving peak demands for natural gas. Under SFV pricing, each customer in a class (for example, each residential heating customer) would pay exactly the same amount for demand-related costs, even though the customers' demands are vastly different. This phenomenon was highlighted in the examples of the tremendous diversity within the residential class, discussed above and in Mr. Rubin's Direct testimony. AG Ex. 9.0 at 2.

The Companies claim that essentially all of the Companies' costs are fixed and should be recovered through fixed charges (NS/PG: Ex. 29.0 at 7, 11), that assertion is inaccurate. A gas distribution system is designed to serve the anticipated peak demands and energy requirements of all customers. Very little if any of that investment is actually "caused" by a single customer. When discussing the principle of cost causation, AG witness Rubin explained, ". . . we're actually talking about a fair way to allocate shared costs among customer classes and customers." AG Ex. 9.0 at 2.

When the Companies allocate costs among customer classes in a cost-of-service study, they recognize the shared nature of these common costs. The Companies allocate those costs to each customer class in a way that we find to be fair to all customers. For example, as NS-PGL witness Hoffman Malueg discusses in her rebuttal testimony (NS-PGL Exhibit 28.0), there are good reasons for allocating the cost of distribution mains based on the average and peak approach which recognizes that mains serve both peak demands and annual energy usage. That is, the allocation of a shared cost (or facility) uses energy usage and/or peak demand to have each customer class pay its fair share of jointly used facilities. AG Ex. 9.0 at 3.

As AG witness Rubin explained, that same principle needs to apply when rates are designed. It makes no sense to say that the cost of serving residential customers is based, in part, on demand and energy usage; but then to design rates that ignore demand and energy usage (as SFV rates would do).

Under SFV pricing, each residential customer would pay exactly the same amount toward the cost of mains. In contrast, under a rate design that mimics the way in which costs are fairly allocated to classes (which is what is meant by cost causation), rates would recognize that the "cost increase" (a shorthand expression for the increase in costs allocated to the class) was caused by just one customer. If the costs of mains are collected based on a customer's energy consumption or demands, then the customer whose consumption doubled would pay most (or ideally all) of the cost increase. That is exactly what happens under a traditional rate design that collects demand-related costs either through a demand charge (when demand metering is in place) or through an energy charge (when demand-metering is not feasible).

A rate design that is consistent with the cost-of-service study's allocation methodology – provides a fair result to all customers. The customer who caused the residential class's cost allocation to increase bears the responsibility for those increased costs. Other customers, whose demands and energy usage did not change, are not asked to subsidize the high-use / high-demand customer.

The Companies propose greater movement toward SFV pricing. This would have the effect of requiring lower-use / lower-demand customers to provide tremendous subsidies to higher-use / higher-demand customers. In contrast, the rate design Mr. Rubin proposes for the residential classes tries to mimic the way in which costs are allocated to the residential class, so that subsidies among residential customers are minimized.

NS/PGL witness Egelhoff further suggests that “SFV rate design reduces the volatility of customers' bills.” NS/PGL Ex. 29.0 at 4. But this is not a legitimate reason to move toward SFV rates. First, Ms. Egelhoff assumes that customers want their bills to be the same all year. There is no evidence that is the case. Even if one assumes they do, then they can enroll in a budget billing plan. Mr. Rubin points out that, in fact, not all customers want this. Some customers want their gas bills to be low in the summer because they incur other expenses in the summer (such as increased electricity costs for air conditioning, or increased child care costs when school is out). Second, Ms. Egelhoff confuses leveling a customer's bill with subsidizing customers through the rate design. It is one thing to offer a customer the option of spreading their annual bill over 12 months. It is quite another to relieve high-use customers of the cost of serving them by having low-use customers pick up the tab. SFV pricing does not just "reduce the volatility of customers' bills"; it also requires low-use customers to pay costs that are incurred to serve higher-use customers. It is grossly unfair and can result in tremendous cross-subsidies within a class.

In the Companies’ last case, part of this unfairness was corrected when the Companies separated non-heating customers from the rest of the residential class. The rates for those very low-use customers were reduced dramatically as a result of their no longer being required to subsidize the demand-related costs of high-use heating customers. The inequity of SFV-type rates, however, remains within the residential heating class. Lower-use heating customers are subsidizing the bills of higher-use heating customers, as Mr. Rubin demonstrated in his direct testimony and as described earlier in this Brief. Moreover, the level of subsidy increases under the Companies' proposal to move even closer to SFV rates by significantly increasing the customer charge.

Other criticisms of AG/ELPC witness Rubin's proposed rate design fall flat. Ms. Egelhoff asserts that because "irrespective of a customer's demand on the peak day, lower usage on other days would reduce the customer's contribution to demand cost recovery" NS/PGL Ex. 29.0 at 8. As pointed out by AG/ELPC witness Rubin, Egelhoff's criticism is valid, but she fails to finish the thought. It is true that the rate design method Mr. Rubin uses is imprecise because it assumes that peak demand is strictly proportional to annual energy usage. Clearly, that is not exactly precise. But Ms. Egelhoff fails to compare this imprecision to her support of SFV rates. An SFV rate design wrongly assumes that the demand-related costs for all residential customers are exactly the same. Mr. Rubin's approach is imprecise because of the limits of current metering technology and other implementation factors. Ms. Egelhoff's method just assumes away the problem and is inconsistent with reality. As Mr. Rubin explained, we know that for most customers within a class, demands bear a pretty close relationship to annual usage. It is not exact, but a customer who averages 200 therms *per* month is going to have much higher peak demands than a customer who uses only 200 therms in an entire year. That is certain. AG/ELPC Ex. 9.0 at 7-8.

Finally, Staff witness William Johnson has recommended that the fixed cost be set at approximately 65%, based on a strict allocation of demand-related costs to variable charges. Staff Ex. 4.0 at 46-48. While this is an improvement over the NS/PGL proposals, it does not go far enough in recognizing other public policy considerations related to rate design, such as equity (avoidance of cross subsidies from low users to high users) and public policy goals related to promoting conservation and energy efficiency.

Staff witness Johnson complained in his Rebuttal testimony that it is unclear how Mr. Rubin derived the figures of 50% and 75%, respectively, for fixed cost recovery in heating and non-heating rates (Staff Ex. 9.0 at 24), and why some customer costs should be recovered through variable charges, rather than the customer charge. But that criticism should be given little weight. As Mr. Rubin explained in his Direct testimony, there are public policy reasons why more costs should be recovered through variable *per*-therm charges than a strict application of placing all customer-related costs, which amount to 63% of costs, in the customer charge.

The facts in this case, which make clear that the Companies have zero risk of not recovering their revenue requirement given the number of riders that have been authorized for the Companies pursuant to statute and Commission order, support a greater shift away from the SFV-like customer charges that have created the extreme inequities highlighted in Mr. Rubin's direct testimony exhibits 3.3 and 3.4. This case provides the opportunity to correct those inequities. Public policy goals of promoting conservation and energy efficiency, which are clearly articulated in Section 8-104 of the

Act and the Commission's recent rate design orders and reports, also support moving away from precise adherence to cost study data.

Mr. Rubin's rate design is consistent with the Companies' own cost study allocations, gives customers more control over their bills (thereby ensuring consistency with the State's energy efficiency goals), and begins to alleviate some of the impacts of modified SFV rate design that have detrimentally impacted low-income customers. The record evidence and recent Commission rate design orders and ICC Report findings support its adoption by the Commission

Commission Analysis and Conclusion

The Commission finds that the Companies proposed increases in the customer charges pursuant to its SFV-based rate design are inconsistent with public policy as discussed in Section IX, B 2 (Fixed Cost Recovery) of this order. The Commission finds that Staff's and Intervenor's arguments in favor of assigning demand based costs to volumetric charges are consistent with energy efficiency and the avoidance of cross subsidies. The Commission accepts Staff's rate design proposal for this customer class, which reflects a more traditional rate design whereby customer charges recover embedded cost-of-service ("ECOS") study customer costs and distribution charges recover ECOS study demand costs. Therefore, customer's bills are more closely aligned with the ECOS study. The customer charges for the S.C. No. 1 Small Residential Service, Heating class should be set to recover the final Commission approved ECOS studies' customer costs. The remaining, non-storage related demand costs, would be recovered through a flat distribution charge on a per therm basis.

c. Service Classification No. 2, General Service

Companies' Position

The Companies stated that, consistent with the rate design objectives and principles applicable to fixed cost recovery, they each proposed to continue to set S.C. No. 1 HTG at cost. NS Ex. 15.0 at 10; PGL Ex. 15.0 REV. at 10. North Shore proposed to recover 80% and Peoples Gas proposed to recovery 75% of non-storage related fixed costs through the customer charge with all remaining non-storage costs being recovered through a flat distribution charge. Each would continue to recover storage-related costs under Rider SSC. NS Ex. 15.0 at 12; PGL Ex. 15.0 REV. at 12. The Companies contend that their proposals are consistent with the Commission policy for gas Companies of gradually increasing fixed cost recovery in fixed charges. To retreat from this gradual movement, as AG/ELPC and Staff proposed, exacerbates the extent to which a customer's bill does not reflect the costs it causes the Companies to incur, *i.e.*, customer usage would drive fixed cost recovery but usage does not drive the Companies' incurrence of those fixed costs.

Staff's Position

Staff argues that the Commission should accept Staff's S.C. No. 2 General Service classes' rate design proposal for North Shore and Peoples Gas.

Staff reiterates that recent Commission orders have been moving towards aligning customers' bills with the cost of service (i.e., customer charges based upon ECOS study customer costs and distribution\demand charges based upon ECOS study demand costs). While the Companies' proposed S.C. No. 2 General Service class customer charge recovers 100% of ECOS customer costs, it also recovers demand related costs. This is a shift towards greater SFV-based rate design and is, thus, problematic. The Commission has recently been making adjustments that move away from SFV-based rate designs for those electric companies that have adopted formula rates through EIMA. Similar to the impact of electric companies' formula rates, the Company's implementation of Rider VBA provides revenue stability and eliminates the need to have an SFV-based rate design. Also, increasing the percentage of non-storage related demand costs through fixed charges lowers the percentage of non-storage related demand costs recovered through the per therm distribution charge. This, in turn, could discourage conservation. Staff Ex. 4.0 at 33-34. Finally, Staff found that moving ECOS study-based demand costs that are allocated to customer classes based upon demand into a fixed customer charge shifts cost responsibility to customers with lower demands. This occurs because rather than collecting total demand related costs on a per therm basis, some of the demand related costs are collected on a per customer basis. The per therm charge is lower than it would have been if all demand related costs were recovered on a per therm basis and the customer charge is higher than it would have been if the demand costs were collected through a per therm charge (for example, a customer that uses zero therms would pay for some of the demands that a larger use customer places on the system). *Id.*

Staff's proposed S.C. No. 2 General Service class customer charge for all three meter classes (for each Company) will recover 100% of ECOS study-based customer costs. Consistent with the most recent Commission orders concerning movement away from SFV-based rate designs, Staff witness Johnson proposes a decrease in the percentage of non-storage related demand costs currently recovered through the customer charge for all three meter classes. His proposal provides a gradual shift away from SFV-based rate design while taking into consideration customer bill impacts and revenue stability for the Company. Specifically, Staff proposes the percentage of non-storage related demand costs recovered through the customer charge for North Shore for Meter Classes 1 and 2 be decreased by 10% from the current Commission approved 45%. The resulting percentage of non-storage related demand costs recovered through North Shore's customer charge for Meter Classes 1 and 2 would be 40%. The same 10% decrease for North Shore's Meter Class 3 would result in a decrease in the percentage of non-storage related demand costs recovered through the customer charge from 35% to 31%. The remaining non-storage related demand costs would be recovered through the Company's proposed declining two-block distribution charge on a per therm basis. Staff Ex. 4.0 at 35-36 and Schedule 4.01N.

For Peoples Gas, Staff proposes the percentage of non-storage related demand costs recovered through the S.C. No. 2 General Service class customer charge for Meter Classes 1, 2, and 3 be decreased by 10% from the current Commission approved 40%, 45%, and 10%, respectively. The resulting percentage of non-storage related demand costs recovered through the customer charge for Peoples Gas would be 36% for Meter Class 1, 40% for Meter Class 2, and 9% for Meter Class 3. The remaining non-storage related demand costs would be recovered through the Company's proposed declining two-block distribution charge on a per therm basis. *Id.* at 54-55 and Schedule 4.01P.

Staff also recommends that, going forward, the Commission make additional adjustments to the percentage of non-storage related demand costs recovered through the S.C. No. 2 General Service class customer charge until the customer charges per meter class recover only ECOS study customer costs for both Companies. Staff is not recommending that a set percentage in each case or time period be utilized to eliminate the non-storage related demand costs from the customer charge going forward. The amount of the adjustments should be decided in each case in order to consider bill impacts for customers. Staff Ex. 4.0 at 36. Recent Commission Orders indicate a movement away from SFV-based rate designs, especially for those Companies with cost recovery mechanisms in place (like the Companies' Rider VBA) that provide revenue stability. Staff's rate design proposal makes a similar movement while taking rate impacts into consideration. Staff Ex. 9.0 at 14.

Commission Analysis and Conclusion

The Commission's recent Orders in ComEd (Docket No. 13-0387) and Ameren Illinois (Docket No. 13-0476) make it clear that SFV-based rate designs should be re-examined and rate design should reflect traditional rate design principles, which more closely align customers' bills with the ECOS study. The Commission is actively reevaluating how rate design can be utilized to ensure that customers are responsible for the demands they place on the system and that rate design maximizes conservation efforts.

With this in mind, the Commission finds that the Companies' proposed increases in the S.C. No. 2 General Service class customer charges pursuant to its SFV-based rate design are inconsistent with public policy as discussed in Section IX, B 2 (Fixed Cost Recovery) of this order. Customer charges for these classes should be set at the levels discussed above, and the remaining non-storage related demand costs should be recovered through the Companies' proposed declining two-block distribution charge on a per therm basis.

This proposal results in a gradual movement away from SFV-based rates for the S.C. No. 2 General Service classes while taking into consideration customer bill impacts and revenue stability for the Companies. Going forward, the Commission directs the Companies to make additional adjustments to the percentage of non-storage related demand costs recovered through the customer charge until the customer charges per meter class recover only ECOS study customer costs. However, this should be done while taking into consideration bill impacts for the customers in the various meter classes.

d. Service Classification No. 4, Large Volume Demand Service

Companies' Position

The Companies stated that, consistent with the rate design objectives and principles applicable to fixed cost recovery, they each proposed to continue to set S.C. No. 4 at cost. NS Ex. 15.0 at 10; PGL Ex. 15.0 REV. at 10. Each proposed to set the monthly customer charge at cost. For North Shore, Companies witness Ms. Egelhoff stated that the demand charge would recover 70% of non-storage related demand costs and the distribution charge would recover all remaining non-storage related demand costs. For Peoples Gas, Ms. Egelhoff stated that the demand charge would continue to recover 55% of non-storage related demand costs and the distribution charge would recover all remaining non-storage related demand costs. For each, storage related costs would be recovered under Rider SSC. NS Ex. 15.0 at 19; PGL Ex. 15.0 REV. at 19.

Staff's Position

Staff believes that the Commission should accept Staff's S.C. No. 4 rate design proposal. The Companies are proposing to set the monthly customer charge at cost to recover all ECOS study customer costs. The customer charge increases from $594 to $656 *per* month for North Shore and the $687 to $982 for Peoples Gas. The proposed demand charge increases from 55.277 cents *per* therm of billing demand to 67.695 cents *per* therm for North Shore and 71.421 cents *per* therm of billing demand to 99.482 cents *per* them for Peoples Gas. The distribution charge recovers the remaining non-storage related demand costs for both Companies. NS Ex. 15.0 at 19 and PGL Ex. 15.0REV. at 19.

Staff witness Johnson has no objection to the Company's rate design proposal for the S. C. No. 4 rate class. The Company is proposing to set the customer charge at cost, which is a minimal part of a customer's bill because customers must use an average of over 41,000 therms *per* month and the customer charge would represent a minimal part of the total bill. The remaining revenues are collected through the demand and distribution charges and the S.C. No. 4 class proposal will recover its full cost of service. However, Mr. Johnson does propose that if the Company's total customer charge revenues derived from the proposed customer charge ($656 NS and $982 PGL) are greater than the customer costs found on the final Commission approved ECOS study, then the final customer charge should be lowered to recover ECOS study customer costs only. Staff Ex. 4.0 at 43.

IIEC's Position

IIEC witness Brian Collins proposes an across the board increase for all classes. IIEC Ex. 1.0 at 3; IIEC Ex. 3.0 at 18-19.

Commission Analysis and Conclusion

The Commission finds that the Company's rate design proposal for the S. C. No. 4 rate class is reasonable and hereby approves it. The Commission reiterates its rejection of the proposed across the board increase in rates which as discussed above is not supported by the record.

3. Classification of SC No. 1 Residential Heating and Non-Heating Customers

Companies' Position

In response to AG/ELPC's claims that a large number of North Shore and Peoples Gas S.C. No. 1 customers appeared to be misclassified between heating and non-heating, the Companies showed that the AG/ELPC analysis was flawed because it focused on usage as the basis for determining if a customer uses gas for space heating, and the Companies' approach of classifying customers based on their gas appliances is more accurate. As Companies witness Mr. Robinson showed, there are often good explanations for why a customer's usage may vary from an expected level. NS-PGL Ex. 32.0 at 4-7. This is why the Companies focus on the customer's appliances and not usage to determine if the customer is an S.C. No. 1 NH or HTG customer. *Id.* at 3, 6.

The Companies explained that they have long-standing processes, pre-dating the introduction of S.C. No. 1 non-heating and heating rates, to identify the customer's appliances. These processes include inquiries when an applicant or customer interacts with a customer service representative and a physical inspection of the premises. *Id.* at 7-8. A sample of data on which the AG witness relied that the Companies reviewed showed that, overwhelmingly and to the extent they had definitive data, customers were correctly classified. While it is certainly possible that some customers are misclassified, it is not likely that 100% accuracy, 100% of the time is achievable, even if the Companies conducted the study that Staff suggested. NS-PGL Ex. 46.0 at 5.

When the utility changes out or installs a meter, this requires a physical inspection of the premises and a verification of appliances. NS-PGL Ex. 32.0 at 7. If a customer is seeking LIHEAP funding but his account is a non-heating account, this will trigger a physical inspection to verify the appliances, as non-heating accounts are not eligible for LIHEAP. *Id.* at 8.

For new construction, the Companies will work with the contractor to ascertain the appliances that will be at the premises. This is necessary for the utility to determine the pipe to install, meter size and other information needed to establish service. In many cases, if utility personnel are at a premise, they inspect and note the appliances, which are then updated in the Companies‟ system. For example, if utility personnel are responding to a gas odor complaint, they will catalog the appliances. These processes help keep the Companies‟ records current and accurate. Certainly, some customers may be misclassified. However, using appliances as the criterion to determine whether a S.C. No. 1 customer is a heating or non-heating customer and the many methods that the Companies use to keep track of appliances at each customer location help ensure a high level of accuracy in classifications. *Id.*

In response to Staff, the Companies stated that, in the limited time available, they were unable to develop a sound cost estimate for a study of classifications, but they explained that the large number of accounts that could require intensive manual review or physical inspections of the premises, or both, suggests that the costs of an in-depth study would almost certainly be millions of dollars and a large commitment of personnel and time. The Companies further explained that, given the existing processes and the large number of customers already subject to review on an annual basis as part of the application process, a study is not needed. *Id.* at 2-4.

Companies' witness Robinson responded in surrebuttal testimony to Staff's recommendation to give a rough estimate of the amount of time it would take to carry out an in-depth study and an estimate of the costs involved. Mr. Robinson stated that subject to the limitations of developing the requested estimates in a short period, the Companies' rough estimate of the number of accounts that would potentially be inspected is approximately 580,000. This estimate is based on information from the Companies' customer information system on the number of premises that did not show a physical verification of appliances in the last three years. The Companies were not able, in the time available, to estimate the costs of further manual review of accounts after the initial query. However, given the large number of accounts, and the need for manual review, physical inspections (possibly including repeat visits when the Companies could not initially gain access to identify all appliances), or both, it would almost certainly be millions of dollars. NS-PGL Ex. 46.0 at 3-4.

Mr. Robinson stated that the Companies do not think a requirement to conduct a study is needed. The Companies rely on identification of gas appliances to categorize a customer as heating or non-heating. They have long-standing processes, pre-dating the introduction of heating and non-heating rates in S.C. No. 1, to identify the customer's appliances. These processes involve both inquiries when an applicant or customer interacts with a customer service representative or a physical inspection of the premises. The application process alone typically involves tens of thousands of applicants in a year. This means that, at a minimum, the Companies are verifying appliances for a large percentage of their customer base every year. Because the inquiries focus on appliances and on following up when the applicant's or customer's description of his appliances does not mesh with existing data that the Companies have about the premises, these existing processes are very effective in correctly categorizing customers. *Id.* at 4.

Companies witness Robinson proposed an alternative to a study or investigation. He stated that it is his understanding that after a rate case order, the Companies must communicate with customers about the rate case. They could use that communication to emphasize to S.C. No. 1 customers the significance of the "heating" and "non-heating" designations and encourage customers to call with questions or concerns. *Id.* at 5.

<u>Staff's Position</u>

AG/ELPC witness Rubin testified that there may be residential customers who are misclassified as between heating and non-heating. AG/ELPC Ex. 3.0 at 3. He states that if customers are misclassified between heating and non-heating classes there could be a large difference in the bills they pay. The AG/ELPC recommends that the Companies investigate and improve the classification of residential customers and report back to the Commission on its findings.

Staff witness Johnson opined that the Commission approved the Companies' establishment of residential heating and non-heating classes in Docket Nos. 12-0511/12-0512 (Consol.). He stated that AG/ELPC witness Rubin does not appear to disagree with the "heating" and "non-heating" sub-classes *per se*, but rather wants to make sure that the customers are classified correctly as heating or non-heating. The Companies' tariffs specifically designate "Heating Customers" as customers who use gas as their principal source of space heating requirements and "Non-Heating Customers" as customers who do not use gas as their principal source of space heating requirements. (North Shore ILL.C.C.No. 17, Ninth Revised Sheet No. 6 and Peoples Gas ILL.C.C.No. 28, Ninth Revised Sheet No. 5.) Staff has no objection to the Companies' designations for these customers found in the tariffs. Staff Ex. 9.0 at 21.

However, because the Commission only approved the bifurcation of the residential class into heating and non-heating classes in Docket No. 12-0511/12-0512 (Consol.), dated June 18, 2013, Mr. Johnson understands why AG witness Rubin would want to make sure that customers are classified correctly. Staff witness Johnson stated that he had no objection to the Commission ordering the Companies to do an in-depth study to make sure that "heating" and "non-heating" customers are classified correctly. However, he emphasized that the Commission should also consider that this will probably involve some on-site inspections that will likely include additional costs.

AG's Position

AG/ELPC witness Rubin testified that there may be residential customers who are misclassified as between heating and non-heating. He states that if customers are misclassified between heating and non-heating classes there could be a large difference in the bills they pay. He gives an example of the rate difference between classifications for Peoples Gas. The non-heating customer charge under present rates is $13.60 *per* month and the *per* therm delivery charge is $0.42032. The heating customer charge is $26.91 *per* month and the *per* therm delivery charge is $0.18885. The AG/ELPC recommends that the Companies investigate and improve the classification of residential customers and report back to the Commission on its findings. AG/ELPC witness Rubin further recommends that if the Companies cannot complete the process by the close of the record in this case, or if they refuse to undertake the task, then the Commission should order the Companies to do so as quickly as possible following the conclusion of this case.

If a customer is seeking LIHEAP funding but his account is a non-heating account, this will trigger a physical inspection to verify the appliances, as non-heating accounts are not eligible for LIHEAP.

For new construction, the Companies will work with the contractor to ascertain the appliances that will be at the premises. This is necessary for the utility to determine the pipe to install, meter size and other information needed to establish service. In many cases, if utility personnel are at a premises, they inspect and note the appliances, which are then updated in the Companies‟ system. For example, if utility personnel are responding to a gas odor complaint, they will catalog the appliances. These processes help keep the Companies‟ records current and accurate. Certainly, some customers may be misclassified. However, using appliances as the criterion to determine whether a S.C. No. 1 customer is a heating or non-heating customer and the many methods that the Companies use to keep track of appliances at each customer location help ensure a high level of accuracy in classifications. *Id.*

Commission Analysis and Conclusion

The Commission finds that the Companies suggestion that in the Companies communication with customers about the rate case, they include information emphasizing to S.C. No. 1 residential heating and non-heating customers the significance of the "heating" and "non-heating" designations and encourage customers to call with questions or concerns or to request an inspection. The Commission directs the Companies to submit the content and format of the proposed heating/ non-heating classification communication to Commission Staff for its input and approval prior to its distribution to customers. The Commission further directs the Companies in preparation for their next rate cases to provide in direct testimony the number of customer contacts that are generated by this communication and the number of inspections and account reclassifications that occur as a result.

D. Other Rate Design Issues

1. Terms and Conditions of Service

a. Service Activation

Companies' Position

Based on a cost study, the Companies proposed changes to some of their Service Activation Charges, which recover a portion of the costs related to initiating gas service at a premises. North Shore proposed no change to its succession turn-on charge, $50.00 for a straight turn-on, and $12.00 for relighting each appliance over four. NS Ex. 15.0 at 20-21; NS Ex. 15.8. Peoples Gas proposed $23.00 for a succession turn-on, $38.00 for a straight turn-on, and $13.00 for relighting each appliance over four. PGL Ex. 15.0 REV. at 20-21; PGL Ex. 15.8 REV.

Staff's Position

The Companies identify two types of service activations. A succession turn-on occurs when a customer who is moving out of a home or building calls to discontinue gas service at approximately the same time as the applicant moving in calls and requests gas service. In this instance, only one meter reading is taken. A straight turn-on occurs when there has never been gas service at a location, or when the prior customer canceled service before the new applicant calls to request service and the gas has actually been turned off. In this instance, the gas has to be turned on and appliances have to be relit. NS Ex. 15.0 at 20 and PGL Ex. 15.0 at 20-21.

North Shore prepared an analysis that identifies the costs associated with a succession turn-on, straight turn-on, and the cost to light an additional appliance over four (Included in any reconnection charge is the relighting of a maximum of four gas appliances *per* account). NS Ex. 15.0 at 20. North Shore's analysis shows that the cost for a succession turn-on is $23.74, the cost of a straight turn-on is $64.07, and the cost to light an additional appliance over four is $16.55. NS Ex. 15.8. North Shore is proposing that the straight turn-on be increased from $42.00 to $50.00, and the cost for relighting any appliances over four be increased from $10.00 to $12.00. North Shore is proposing to leave the succession turn-on charge at $20.00. NS Ex. 15.0 at 21.

PGL prepared an analysis that identifies the costs associated with a succession turn-on, straight turn-on, and the cost to light an additional appliance over four (Included in any reconnection charge is the relighting of a maximum of four gas appliances *per* account). NS Ex. 15.0 at 21. PGL's analysis shows that the cost for a succession turn-on is $25.89, the cost of a straight turn-on is $63.42, and the cost to light an additional appliance over four is $17.23. PGL Ex. 15.8. PGL is proposing that the succession turn-on be increased from $18.00 to $23.00, the straight turn-on be increased from $30.00 to $38.00, and the cost for relighting any appliances over four be increased from $10.00 to $13.00. PGL Ex. 15.0 at 21.

Staff witness Johnson has no objection to the Companies' proposals for Service Activation Charges. He stated that they have provided cost break-downs for the various Service Activation Charges and in the interest of gradualism, are not proposing full cost recovery in this proceeding. Staff Ex. 4.0 at 66.

Commission Analysis and Conclusion

The Commission finds that the Companies' proposal for Service Activation Charges is reasonable. The Commission approves the proposal.

b. Service Reconnection Charges

Companies' Position

Based on a cost study, the Companies proposed changes to some of their Service Reconnection Charges, which they assess customers whose gas has been turned off (*e.g.*, disconnections for non-payment or at the customer's request). Each customer receives a waiver of one reconnection charge each year for reconnection at the meter, except where the customer voluntarily disconnects and then requests reconnection within twelve months. North Shore proposed no change for reconnection at the meter, $180.00 when the meter has to be reset, $500.00 when service has to be reconnected at the main, and $12.00 to relight each appliance over four. NS Ex. 15.0 at 21-22; NS Ex. 15.8. Peoples Gas proposed $94.00 for reconnection at the meter, $188.00 when the meter has to be reset, $500.00 when service has to be reconnected at the main, and $13.00 to relight each appliance over four. PGL Ex. 15.0 REV. at 21-22; PGL Ex. 15.8 REV.

Staff's Position

A service reconnection charge is applicable to customers, whose gas has been turned off for any number of reasons, including disconnections for non-payment of bills and at the customer's request. However, each customer is granted a waiver of one reconnection charge each year for reconnection at the meter, except in the situation where the customer voluntarily disconnects and then requests reconnection within twelve months. The Companies offer three types of service reconnections following an involuntary disconnection for which the Companies currently charge customers: basic reconnections which only require a meter turn-on, reconnections which require setting a new meter, and reconnections that involve excavating at the main. NS Ex. 15.0 at 21; PGL Ex. 15.0 at 21.

North Shore prepared an analysis that identifies the costs associated with the three service reconnections (basic reconnections, reconnections which require a new meter set, and reconnections that involve excavations at the main). NS Ex. 15.0 at 21. North Shore's analysis shows that the cost for a reconnection at the meter (basic reconnection) is $90.72, the cost for a reconnection when the meter has to be reset is $200.46, and the cost for a reconnection at the main is $1,638.63. NS Ex. 15.8. North Shore is proposing that the basic reconnection charge remain at $75.00, the cost for reconnection when the meter has to be reset increased from $150.00 to $180.00, and the cost for reconnection at the main increased from $425.00 to $500.00. The Company is also proposing that the charge for relighting each appliance over four will be increased from $10.00 to $12.00, as with the Service Activation Charge. NS Ex. 15.0 at 21-22.

PGL also prepared an analysis that identifies the costs associated with the three service reconnections (basic reconnections, reconnections which require a new meter set, and reconnections that involve excavations at the main). PGL Ex. 15.0 at 21. PGL's analysis shows that the cost for a reconnection at the meter (basic reconnection) is $112.33, the cost for a reconnection when the meter has to be reset is $439.80, and the cost for a reconnection at the main is $1,338.72. PGL Ex. 15.8. PGL is proposing that the basis reconnection charge increase from $75.00 to $94.00, the cost for reconnection when the meter has to be reset increased from $150.00 to $180.00, and the cost for reconnection at the main increased from $425.00 to $500.00. The Company is also proposing that the charge for relighting each appliance over four will be increased from $10.00 to $12.00, as with the Service Activation Charge. NS Ex. 15.0 at 21-22.

Staff witness Johnson has no objection to the Companies' proposals for Reconnection Charges. He states that the Companies have provided cost break-downs for the various Service Activation Charges and in the interest of gradualism, are not proposing full cost recovery in this proceeding. Staff Ex. 4.0 at 68.

No other parties addressed this issue.

Commission Analysis and Conclusion

The Commission finds that the Companies' proposal for Reconnection Charges is reasonable. The Commission approves the proposal.

c. Second Pulse Data Capability Charge

Companies' Position

A customer with certain metering devices may choose to have the Companies enable second pulse capability. Based on cost studies, the Companies proposed to decrease the Second Pulse Data Capability charge from $14.00 to $10.25 (North Shore) and to $10.60 (Peoples Gas). NS Ex. 15.0 at 22; NS Ex. 15.12; PGL Ex. 15.0 REV. at 22; PGL Ex. 15.12. The Companies agreed with Staff's proposal to update the charges using the rate of return that the Commission approves. NS-PGL Ex. 29.0 REV. at 24.

Staff's Position

A customer that has installed an operational meter, meter corrector, or daily demand measurement device capable of providing a second pulse for further data collection capability may choose to have the Companies enable this capability on the meter or device for a monthly charge. NS Ex. 15.0 at 22 and PGL Ex. 15.0 at 22.

The Companies provided analyses of the determination of Second Pulse Capability Charges. NS Ex. 15.12; PGL Ex. 15.12. The analysis for North Shore identified that the monthly charge for Second Pulse Data Capability would be $10.25, a decrease from the current charge of $14.00. The analysis for Peoples Gas identified that the monthly charge for Second Pulse Data Capability would be $10.60, a decrease from the current charge of $14.00. *Id.*

Staff witness Johnson stated that he had no objection to the Companies' proposals for Second Pulse Data Capability Charges. However, the Companies have incorporated a rate of return of 7.02% in the calculation of the charge that is based upon the

Companies' proposed rate of return. Mr. Johnson recommends the charge be recalculated with the final Commission approved overall rate of return in this proceeding. In response to Staff Data Requests, the Companies stated that they agree that it would be appropriate to update the calculation using the approved overall rate of return set by the Commission in its final Order. Staff Ex. 4.0 at 69.

No other parties addressed this issue.

Commission Analysis and Conclusion

The Commission approves the Companies' proposals for Second Pulse Data Capability Charges recalculated using the final Commission approved overall rate of return in this proceeding.

2. Riders

a. Rider 5, Gas Service Pipe

The Companies proposed clarifying language concerning installation and cost responsibility for service pipe and an editorial change to Rider 5, Gas Service Pipe. In particular, the Companies proposed that the pipe installation will meet certain location requirements when practicable and, if it is not practicable and if the reason is not a customer's request or other circumstance for which the customer bears cost responsibility, then the full installation is at the company's expense. NS Ex. 15.0 at 26 27; PGL Ex. 15.0 REV. at 26-27.

The Commission approves the Companies' proposed clarifying language concerning installation and cost responsibility for service pipe and an editorial change to Rider 5, Gas Service Pipe.

b. Rider SSC, Storage Service Charge

The Companies are proposing a change in the *per* therm charge for the storage service charge resulting from the new revenue requirements proposed in this proceeding. NS Ex. 15.0 at 22; PGL Ex. 15.0 Rev. at 22-23. No party objected to the Companies' proposals.

The Commission approves the Companies' proposed change in the *per* therm charge for the storage service charge resulting from the new revenue requirements proposed in this proceeding.

c. Rider QIP, Qualifying Infrastructure Plant [PGL]

Staff and Peoples Gas agree that language changes to Rider QIP should be made to allow for an adjustment through the Rider QIP surcharge if its 2014 actual additions are different than the amount approved in the instant case. NS-PGL Ex. 29.0 at 24-27; NS-PGL Ex. 29.1; Staff Ex. 6.0 at 14. Further, Staff and the Company are in agreement for the need for a findings and ordering paragraph to be included in the Commission's Order concerning Rider QIP. If the Commission's conclusion accepts the AG adjustment to the projected level of 2014 AMRP plant additions recoverable through Rider QIP, the language is as follows:

> Peoples Gas shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $115,986,348, less a negative amount of $33,721,806 for accumulated depreciation and less a positive amount of $8,603,652 for accumulated deferred income taxes, and $1,728,342 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired.

NS-PGL Ex.37.5 P at 3-4; NS-PGL Ex. 43.0 REV.

If the Commission's conclusion rejects the AG adjustment to the projected level of 2014 AMRP plant additions recoverable through Rider QIP and instead accepts Peoples Gas' position, the language is as follows:

> Peoples Gas shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $173,237,532, less a negative amount of $58,686,380 for accumulated depreciation and less a positive amount of $16,463,375 for accumulated deferred income taxes, and $2,620,588 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired.

NS-PGL Ex. 22.14 P; NS-PGL Ex. 43.0 REV.

The Commission approves the Companies' proposed language changes to Rider QIP to allow for an adjustment through the Rider QIP surcharge if its 2014 actual additions are different than the amount approved in the instant case.

d. Rider UEA, Uncollectible Expense Adjustment, and Rider UEA-GC, Uncollectible Expense Adjustment – Gas Costs

The Companies each proposed revising Rider UEA-GC to reflect the proposed Uncollectible Factors arising from data in this case and Rider UEA to reflect the updated uncollectible amount to be recovered in base rates based on the final revenue requirements determined by the Commission in these cases. NS Ex. 15.0 at 25-26; NS Ex. 15.11; PGL Ex. 15.0 REV. at 25-26; PGL Ex. 15.11.

The Commission approves the Companies' proposed revision of Rider UEA-GC to reflect the proposed Uncollectible Factors arising from data in this case and Rider UEA to reflect the updated uncollectible amount to be recovered in base rates based on the final revenue requirements determined by the Commission

e. Rider VBA, Volume Balancing Adjustment, percentage of Fixed Costs

The Companies' proposed revenue increase and rate design would result in new distribution rates and related distribution revenues ("Rate Case Revenues" or "RCR") for Rider VBA. The Companies proposed the Rider VBA Percentage of Fixed Costs ("PFC") be set at 100%. NS Ex. 15.0 at 12-13, 18; PGL Ex. 15.0 REV. at 12-13, 18.

The Commission agrees that it is necessary under Rider VBA for the Companies to file RCRs and it directs the Companies to do so. The Commission also finds that the PFC should be set at 100%. The Companies' proposals are uncontested and approved.

f. Transportation Riders

i. Transportation Administrative Charges

Based on cost studies, North Shore proposed to increase the Administrative Charge for Riders FST, Full Standby Transportation Service, and SST, Subscription Storage Transportation Service, from $5.74 to $6.14 *per* account and the Pooling Charge for Rider P, Pooling Service, from $1.97 to $2.98 *per* account. NS Ex. 15.0 at 23; NS Ex. 15.9. Peoples Gas proposed to decrease the Riders FST and SST Administrative Charge from $7.78 to $5.82 *per* account and the Rider P Pooling Charge from $5.39 to $4.18 *per* account. PGL Ex. 15.0 REV. at 23; PGL Ex. 15.9.

The Commission finds that the Companies' proposed Administrative and Pooling Charges are appropriate and reasonable. The proposals are based on an uncontested cost study. The Commission approves the Companies' proposed Administrative and Pooling Charges.

ii. Rider SBO Credit

The Companies' Rider SBO, Supplier Bill Option Service, allows suppliers providing service to Rider CFY customers to render their own bills to the customers for their services and the Companies' delivery service. The Companies provide a credit to suppliers to compensate them for the Companies' avoided billing cost. Based on a cost study, the Companies proposed to increase the credit from 46 to 47 cents *per* bill *per* month. NS Ex. 15.0 at 23; NS Ex. 15.10; PGL Ex. 15.0 REV. at 23-24; PGL Ex. 15.10.

The Commission finds that the proposed Rider SBO credit is reasonable and based on an uncontested cost study. The Commission approves the proposed Rider SBO credit.

iii. Purchase of Receivables

The Companies observed that Ameren filed for approval of a small volume transportation program, and its proposal includes language to allow utility consolidated billing/purchase of receivables. The Companies witness Ms. Egelhoff stated that the Companies plan to review Ameren's filing and monitor the Commission proceeding.

Based on what the Commission determines for Ameren, they plan to develop and file, in 2015 for 2016 implementation, a purchase of receivables tariff. NS Ex. 15.0 at 24; PGL Ex. 15.0 REV. at 24. The Companies noted that the Commission has not yet issued an Order in the Ameren case, Docket No. 14-0097.

The Commission notes that neither Staff nor intervenors commented on the Companies' proposal. The Commission takes no position on the proposal but will review the merits of any proposed tariff when it is filed.

3. Service Classifications

a. Service Classification Nos. 1 and 2 Terms of Service

The Companies proposed clarifications in the S.C. Nos. 1 and 2 "Terms of Service" language to distinguish more clearly service discontinuance under the Commission's rules (*e.g.*, due to non-payment) from service discontinuance at the customer's request (*e.g.*, when a customer moves). NS Ex. 15.0 at 26; PGL Ex. 15.0 REV. at 26.

The Commission approves the Companies' proposed clarifications to S.C. Nos. 1 and 2. These uncontested proposals are reasonable and are hereby adopted.

X. 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 found to be just and reasonable should be the 12 months ending December 31, 2015; such test year is appropriate for purposes of this proceeding;

(6) the $443,539,000 original cost of plant for North Shore at December 31, 2012, and the $3,285,370,000 original cost of plant for Peoples Gas at December 31, 2012, as presented in Staff Ex.6.0, are unconditionally approved as the original costs of plant;

(7) for the test year ending December 31, 2015, and for the purposes of this proceeding, Peoples Gas' original cost rate base with adjustments is $1,704,364,000;

(8) for the test year ending December 31, 2015, and for the purposes of this proceeding, North Shore's original cost rate base with adjustments is $219,042,000;

(9) a just and reasonable return which Peoples Gas should be allowed to earn on its net original cost rate base is 6.56%; this rate of return incorporates a return on common equity of 9.05% and costs of long-term debt of 4.32% and short-term debt of 0.91%, with a just and reasonable capital structure of 50.33% common equity, 46.51% long-term debt and 3.16% short-term debt;

(10) a just and reasonable return which North Shore should be allowed to earn on its net original cost rate base is 6.26%; this rate of return incorporates a return on common equity of 9.05% and costs of long-term debt of 4.13% and short-term debt of .74%, with a just and reasonable capital structure of 50.48% common equity, 38.94% long-term debt and 10.58% short-term debt;

(11) Peoples Gas' rate of return set forth in Finding (9) results in approved base rate net operating income of $111,806,000;

(12) North Shore's rate of return set forth in Finding (10) results in approved base rate net operating income of $13,708,000;

(13) pursuant to Section 9-229 of the Act, the Commission has specifically assessed the amounts expended by North Shore and Peoples Gas to compensate attorneys and experts to prepare and litigate this general rate case filing and finds those amounts as adjusted in Sections V.B.13, V.C. 3.a.iv, and V.C.4 to be just and reasonable;

(14) 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;

(15) 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;

(16) the specific rates proposed by Peoples Gas in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, expenses, cost of service allocations, and rate design; Peoples Gas'

proposed rates should be permanently canceled and annulled consistent with the findings herein;

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

(18) Peoples Gas should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $655,025,000, in addition to $16,606,000 of other revenues, which represents a total base rate increase of $74,765,000 or 12.53% in base rate revenues; 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;

(19) North Shore should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $86,358,000, in addition to $1,597,000 of other revenues, which represents a base rate increase of $ 3,701,000 or 4.45% in base rate revenues; 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;

(20) it is further ordered that the uncollectible expense included in base rates for People Gas is $13,692,000 and for North Shore is $498,000, which excludes amounts recoverable under Rider UEA-GC;

(21) The test year amounts of test year pipelines safety-related training for Peoples Gas are: $11,355 for Corrosion-NACE Levels 1 and 2 Certification; $80,500 for 49 CFR Parts 191 and 192 Training; $0 for Construction Inspection; $6,300 for all other pipeline safety-related training, totaling $98,135;

(22) 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 designs set forth and referred to herein, including revisions to their Schedule of Rates for Gas Service;

(23) the percentage of fixed costs for purposes of computations under Rider VBA shall be 100% for each of North Shore and Peoples Gas and North Shore and Peoples Gas shall file revised Rate Case Revenues for Rider VBA;

(24) Peoples Gas shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in

base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $115,986,348, less a negative amount of $33,721,806 for accumulated depreciation and less a positive amount of $8,603,652 for accumulated deferred income taxes, and $1,728,342 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired;

(25) as required in this Order, under the discussion of Rider SSC, Storage Service Charge, North Shore and Peoples Gas shall file Rider SSC charges (Storage Banking Charge and Storage Service Charge) consistent with the approved revenue requirements;

(26) 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; and

(27) North Shore and Peoples Gas' updated depreciation rates are uncontested and they are approved.

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 26, 2014, are permanently canceled and annulled.

IT IS FURTHER ORDERED the $443,539,000 original cost of plant for North Shore at December 31, 2012, and the $3,285,370 original cost of plant for Peoples Gas at December 31, 2012, as presented in Staff Ex. 1.0, 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 (18) and (19) of this Order, applicable to service furnished on and after the effective date of said tariff sheets, which date shall be no later than four business days after said sheets are filed.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company shall revise their Schedule of Rates for Gas Service in accordance with Finding 22 of this Order.

IT IS FURTHER ORDERED that the Peoples Gas Light and Coke Company and North Shore Gas Company shall file revised Rider VBA Rate Case Revenue amounts and set the percentage of fixed costs for purposes of computations under Rider VBA at 100%.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $115,986,348, less a negative amount of $33,721,806 for accumulated depreciation and less a positive amount of $8,603,652 for accumulated deferred income taxes, and $1,728,342 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company shall file Rider SSC charges (Storage Banking Charge and Storage Service Charge) consistent with the approved revenue requirements.

IT IS FURTHER ORDERED that the Utilities' updated depreciation rates are approved.

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.

Entered this 21st day of January, 2015.

BY ORDER OF THE COMMISSION